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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, 2014
Commission File Number: No. 1-12384

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

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

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

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

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

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

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

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

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

None

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

None

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

ý Annual Information Form ý Annual Audited Financial Statements

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

Common Shares	**As of December 31, 2014 there were 1,444,119,940 Common Shares issued and outstanding**
Preferred Shares	**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 preceding 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

INCORPORATION BY REFERENCE

The Registrant's Annual Information Form dated February 26, 2015, included in this annual report on Form 40-F, and Audited Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2014, included as Exhibit 99-1 and Exhibit 99-2, respectively, to this annual report on Form 40-F, are incorporated by reference into and as an exhibit to, as applicable, each of the Registrant's Registration Statements under the Securities Act of 1933: Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-10 (File No. 333-196501).

SUNCOR ENERGY INC.

ANNUAL INFORMATION FORM

Dated February 26, 2015

ANNUAL INFORMATION FORM DATED FEBRUARY 26, 2015

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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 arrangements, unless the context otherwise requires. References to the "Board of Directors" or the "Board" mean the Board of Directors of Suncor Energy Inc.

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.

References to our 2014 audited Consolidated Financial Statements mean Suncor's audited Consolidated Financial Statements prepared in accordance with Canadian generally accepted accounting principles (GAAP), which is within the framework of International Financial Reporting Standards (IFRS), the notes and the auditors' report, as at and for each year in the two-year period ended December 31, 2014. References to our MD&A mean Suncor's Management's Discussion and Analysis, dated February 26, 2015.

This AIF contains forward-looking statements based on Suncor's current plans, 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 material assumptions underlying our forward-looking statements.

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

Crude oil is a mixture consisting mainly 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** is a naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons that are too heavy or thick to flow or be pumped without being diluted or heated and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods. After it is extracted, bitumen may be upgraded into crude oil and other petroleum products.
>
> **Light and Medium Oil** is crude oil with a relative density greater than 22.3 degrees API gravity.
>
> **Oil sands** are naturally occurring stratified deposits of unconsolidated sand/sandstone and other sedimentary rocks saturated with varying amounts of water and bitumen.
>
> **Synthetic crude oil (SCO)** is a mixture of liquid hydrocarbons derived by upgrading bitumen, kerogen or other substances such as coal, or derived from gas to liquid conversion and may contain sulphur or other compounds. Yields of SCO from Suncor's upgrading processes are approximately 80% of bitumen feedstock input, and may vary depending on the source of bitumen. 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**.

Natural gas is naturally occurring mixtures of hydrocarbon gases and other gases.

Conventional natural gas is natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

Natural gas liquids (NGLs) are hydrocarbon components that can be recovered from natural gas as a liquid, including, but not limited to, ethane, propane, butanes, pentanes, and condensates. **Liquefied petroleum gas (LPG)** consists predominantly of propane and/or butane and, in Canada, frequently includes ethane.

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, including costs of drilling exploratory wells and exploratory type stratigraphic test wells.

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

Reservoir is a subsurface rock unit that contains an accumulation of petroleum.

Wells:

> **Delineation wells** are drilled for the purpose of assessing the stratigraphy, structure and bitumen saturation of an oil sands lease. The wells are also used to define known accumulations for the assignment of reserves.
>
> **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.
>
> **Disposal wells** are drilled in which waste fluids can be injected for safe disposal. These wells are subject to regulatory requirement to avoid the contamination of freshwater aquifers.
>
> **Dry holes** 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 of discovering commercial reservoirs or deposits of crude oil and/or natural gas.
>
> **Infill wells** are drilled between existing development wells to target regions of the reservoir containing bypassed hydrocarbon or to accelerate production.
>
> **Observation wells** are used to monitor changes in a producing field. Parameters being monitored include fluid saturations and reservoir pressure.

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

Sidetrack wells are secondary wellbores drilled away from an original wellbore. These enable the bypass of an unusable section of the original wellbore or allow for exploration of a nearby geological feature.

Stratigraphic wells are usually drilled without the intention of being completed for production and are geologically directed to obtain information pertaining to a specific geologic condition, such as **core hole drilling** or **delineation wells** on oil sands leases, or to measure the commercial potential (i.e. size and quality) of a discovery, such as **appraisal wells** for offshore discoveries.

Production processes

Downstream refers to the refining of 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 SCO for the company's oil sands operations, or ii) crude oil and/or other components required in the production of refined petroleum product for the company's downstream operations.

In situ refers to methods of extracting bitumen from deep deposits of oil sands by means other than surface mining.

Midstream refers to transportation, storage and wholesale marketing of crude or refined petroleum products.

Overburden is the material overlying oil sands that must be removed before mining. Overburden is removed on an ongoing basis to continually expose the ore.

Production sharing contracts (PSC) are a common type of contract, outside North America, 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 of the resource and operation of associated facilities. The resource extraction company does not obtain title to the product; however, the company is subject to the upstream risks and rewards. An **exploration and production sharing agreement (EPSA)** is a form of PSC, which also states which parties are responsible for exploration activities.

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 water (converted to steam) required to produce one cubic metre of oil. A lower ratio indicates more efficient use of steam.

Tailings Reduction Operations (TRO $_{TM}$) is a process involving rapidly converting fluid fine tailings into a solid landscape suitable for reclamation. In this process, mature fine tailings are mixed with a polymer flocculent and deposited in thin layers over sand beaches with 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.

Upgrading is the two-stage process by which bitumen is converted into SCO.

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 periodically and later sold as a byproduct.

Secondary upgrading, a purification process also referred to as hydrotreating, adds hydrogen to, and reduces the sulphur and nitrogen of, primary upgrading output to create sweet SCO 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 and Best Estimate Contingent Resources 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

bbl(s)	barrel(s)
bbls/d	barrels per day
mbbls	thousands of barrels
mbbls/d	thousands of barrels per day
mmbbls	millions of barrels
mmbbls/d	millions of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mmboe	millions of barrels of oil equivalent
mmboe/d	millions of barrels of oil equivalent per day
mcf	thousands of cubic feet of natural gas
mcf/d	thousands of cubic feet of natural gas per day
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcf/d	millions of cubic feet of natural gas per day
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
bcf	billions of cubic feet of natural gas
bcfe	billions of cubic feet off natural gas equivalent
GJ	gigajoules
mmbtu	millions of British thermal units
m^3	cubic metres
m^3/d	cubic metres per day
km	kilometres
MW	megawatts

Places and Currencies

U.S.	United States
U.K.	United Kingdom
B.C.	British Columbia
$ or Cdn$	Canadian dollars
US$	United States dollars
£	Pounds sterling
€	Euros

Products, Markets and Processes

WTI	West Texas Intermediate
WCS	Western Canadian Select
NGL(s)	natural gas liquid(s)
LPG	liquefied petroleum gas
SCO	synthetic crude oil
NYMEX	New York Mercantile Exchange
TSX	Toronto Stock Exchange
NYSE	New York Stock Exchange
SAGD	steam-assisted gravity drainage
PSC	production sharing contract
EPSA	exploration and production sharing agreement

Suncor converts certain natural gas volumes to boe, boe/d, mboe, mboe/d or mmboe on the basis of six mcf to one boe. Any figure presented in boe, boe/d, mboe, mboe/d, or mmboe may be misleading, particularly if used in isolation. A conversion ratio of six mcf of natural gas to one bbl of crude oil or NGLs 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 m^3 natural gas = 35.49 cubic feet
1 m^3 overburden = 1.31 cubic yards
1 tonne = 0.984 tons (long)
1 tonne = 1.102 tons (short)
1 kilometre = 0.62 miles
1 hectare = 2.5 acres

(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* (the CBCA) 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, the company further amalgamated with a wholly owned subsidiary under the CBCA. We amended our articles in 1995 to move our registered office from Toronto, Ontario, to Calgary, Alberta, and again in April 1997 to adopt the name, "Suncor Energy Inc.". In April 1997, May 2000, May 2002, and May 2008, the company amended its articles to divide its issued and outstanding shares on a two-for-one basis.

Pursuant to an 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.", referred to in this document as the "merger". The merger was effected pursuant to the CBCA.

Our registered and head office is located at 150 – 6 th 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, 2014, 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 Products Inc.	Canada	A subsidiary that holds interests in the company's energy marketing and renewable energy businesses, and which is a partner of Suncor Energy Products Partnership.
Suncor Energy Products Partnership	Canada	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Marketing Inc.	Canada	A subsidiary of Suncor Energy Products Inc. through which production from our upstream North American businesses is marketed. Through this subsidiary, we also administer Suncor's energy trading and power activities, market certain third-party products, procure crude oil feedstock and natural gas for our downstream business, and procure and market NGLs and LPG for our downstream business.
U.S. operations		
Suncor Energy (U.S.A.) Marketing Inc.	U.S.	A subsidiary that procures and markets third-party crude oil, in addition to procuring crude oil feedstock for the company's refining operations.
Suncor Energy (U.S.A.) Inc.	U.S.	A subsidiary through which our U.S. refining and marketing operations are conducted.
International operations		
Suncor Energy UK Limited	U.K.	A subsidiary through which certain of our operations are conducted in the U.K.
Suncor Energy Oil (North Africa) GmbH	Germany	A subsidiary through which the majority of our Libya operations are conducted.

The company's remaining subsidiaries each accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2014, and (ii) less than 10% of the company's consolidated operating revenues for the fiscal year ended December 31, 2014. 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 headquartered 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; we transport and refine crude oil, and we market petroleum and petrochemical products primarily in Canada. Periodically, we market third-party petroleum products. We also conduct energy trading activities focused principally on the marketing and trading of crude oil, natural gas and byproducts.

Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in the Athabasca oil sands of northeast Alberta, recovers bitumen from mining and in situ operations and either upgrades this production into SCO for refinery feedstock and diesel fuel, or blends the bitumen with diluent for direct sale to market. The Oil Sands segment includes:

- **Oil Sands operations** refer to Suncor's wholly owned and operated mining, extraction, upgrading, in situ and related logistics and storage assets in the Athabasca oil sands region. Oil Sands operations consist of:

    - **Oil Sands Base** operations include the Millennium and North Steepbank mining and extraction operations, 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 Suncor's TRO$_{TM}$ assets.

    - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities, cogeneration units and hot bitumen infrastructure, including insulated pipelines, diluent import capabilities and a cooling and blending facility, and related storage assets. In Situ production is either upgraded by Oil Sands Base, or blended with diluent and marketed directly to customers.

- **Oil Sands ventures** operations include Suncor's 40.8% interest in the Fort Hills mining project, where Suncor is the operator, and its 36.75% interest in the Joslyn North mining project, where Total E&P Canada Ltd. (Total) is the operator. The company also holds a 12.0% interest in the Syncrude oil sands mining and upgrading operation.

EXPLORATION AND PRODUCTION

Suncor's Exploration and Production (E&P) segment consists of offshore operations off the east coast of Canada and in the North Sea, and onshore assets in North America, Libya and Syria.

- **E&P Canada** operations include Suncor's 37.675% working interest in Terra Nova, which Suncor operates. Suncor also holds a 20.0% 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. Suncor also holds interests in several exploration licences offshore Newfoundland and Labrador and Nova Scotia. E&P Canada also includes Suncor's working interests in unconventional natural gas properties in northeast B.C.

- **E&P International** operations include Suncor's 29.89% working interest in Buzzard and its 26.69% interest in Golden Eagle. Both projects are located in the U.K. sector of the North Sea and are operated by another company. Suncor also holds interests in several exploration licences offshore the U.K. and Norway. Suncor owns, pursuant to EPSAs, working interests in the exploration and development of oilfields in the Sirte Basin in Libya. Suncor also owns, pursuant to a PSC, an interest in the Ebla gas development in the Ash Shaer and Cherrife areas in Syria. Suncor's operations in Syria were suspended indefinitely in 2011, due to political unrest in the country.

REFINING AND MARKETING

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

- **Refining and Supply** operations refine crude oil and intermediate feedstock into a broad range of petroleum and petrochemical products. Refining and Supply consists of:
    - **Eastern North America** operations which include a refinery located in Montreal, Quebec, a refinery located in Sarnia, Ontario, and a lubricants business located in Mississauga, Ontario that manufactures and blends products which are marketed worldwide.
    - **Western North America** operations which include refineries located in Edmonton, Alberta and Commerce City, Colorado.
    - Other Refining and Supply assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the U.S.
- **Downstream Marketing** operations sell refined petroleum products to retail, commercial and industrial customers through a combination of company-owned, Petro-Canada 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. Lubricant products are marketed worldwide through company-operated locations and distributor networks.

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 marketing, supply and trading activities, and other activities not directly attributable to any other operating segment.

- **Renewable Energy** interests include seven wind facilities across Canada, including Adelaide which is the most recent addition to the portfolio, and the St. Clair ethanol plant in Ontario. An eighth wind farm, Cedar Point, is planned to commence commercial operations later in 2015.
- **Energy Trading** activities primarily involve the marketing, supply and trading of crude oil, natural gas, power and byproducts, and the use of midstream infrastructure and financial derivatives to optimize related trading strategies.
- **Corporate** activities include 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 product between the company's segments and insurance for a portion of the company's operations by the **Corporate** captive insurance entity.

Three-Year History

Over the last three years, several events have influenced the general development of Suncor's business.

2012

- **Steve Williams appointed as Chief Executive Officer.** In December 2011, Steve Williams, formerly Suncor's Chief Operating Officer (COO), was appointed president and a member of the company's Board of Directors, and assumed the role of Chief Executive Officer (CEO) in May 2012. Prior to becoming COO, Mr. Williams served as Executive Vice President, Oil Sands for four years where he was responsible for leading Suncor's Oil Sands operations through a significant period of growth.

- **TRO_{TM} commissioned.** Suncor completed installation of its tailings management assets. Infrastructure included pipes, pumphouses and fluid transfer barges that (a) pump tailings water from extraction plants to a sand placement area, (b) pump mature fine tailings from the sand placement area to a tailings pond for TRO_{TM} treatment, and (c) pump treated water from tailings ponds back to extraction plants for use in production processes. Through the TRO_{TM} process, mature fine tailings are converted more rapidly into a solid material suitable for reclamation.

- **Off-station maintenance at East Coast Canada assets.** The Floating Production, Storage and Offloading (FPSO) vessels for both Terra Nova and White Rose were disconnected and transported to docking facilities for planned maintenance. The water injection swivel was replaced on the Terra Nova FPSO, while the propulsion system was repaired on the White Rose FPSO. The off-station maintenance program for Terra Nova also allowed the company to replace subsea infrastructure to help mitigate hydrogen sulphide (H_2S) issues.

- **Growth at Firebag.** Production from Firebag increased to 104 mbbls/d, approximately 75% higher than the 2011 production level. Firebag Stage 3 central processing facilities reached design capacity in 2012 approximately one year after first oil was brought on-stream. Stage 4 central processing facilities were commissioned and first oil from Stage 4 wells was brought on-stream in December 2012.

- **MNU commences operations.** The Millennium Naphtha Unit (MNU), which consists of a hydrogen plant and a naphtha hydrotreating unit, began operating at design rates. The MNU increased sweet SCO production capacity, primarily through a naphtha hydrotreating unit and stabilizing secondary upgrading processes by providing flexibility with respect to hydrogen production during planned or unplanned maintenance.

- **Oil Sands logistics infrastructure brought into service.** The company brought into service the Wood Buffalo pipeline, which connects the company's Athabasca terminal at the base plant in Fort McMurray to other third-party pipeline infrastructure in Cheecham, Alberta, and four storage tanks in Hardisty, Alberta, which are connected to the Enbridge Inc. (Enbridge) mainline pipeline.

- **Hebron project receives sanction.** In December, the co-owners of the Hebron project sanctioned a development plan that includes a concrete gravity-based structure (GBS) supporting an integrated topsides deck to be used for production, drilling and accommodations. The estimated gross oil production capacity for Hebron is 150 mbbls/d.

2013

- **Voyageur oil sands upgrader project deferred.** In March, Suncor announced that it was not proceeding with the Voyageur upgrader project in response to changed market conditions that challenged the project economics. Suncor acquired Total's interest in Voyageur Upgrader Limited Partnership (VULP) for $515 million to gain full control of VULP's assets, including a hot bitumen blending facility and tankage used to support the company's growing Oil Sands operations.

- **Majority of natural gas business in Western Canada sold.** Suncor sold its conventional natural gas business in Western Canada with an effective date of January 1, 2013. The transaction closed September 26, 2013 for gross proceeds of $1 billion, before closing adjustments and other closing costs. The sale included properties situated across multiple regions in Alberta, northeast British Columbia and southern Saskatchewan but excluded the majority of Suncor's unconventional natural gas properties in the Kobes region (Montney formation) of northeast British Columbia and unconventional oil properties in the Wilson Creek area (Cardium formation) of central Alberta.

- **Suncor constructs wetland.** The company reached a reclamation milestone with the planting of a fen wetland at Oil Sands Base. A fen is a specific type of peat-accumulating wetland. Suncor is one of the first companies in the world to attempt reconstruction of this type of wetland. Construction of the fen's underlying watershed was completed in January 2013, and vegetation was planted during the spring and summer.

- **Firebag ramp-up completed.** Firebag production in 2013 increased by approximately 40% over 2012

production levels as the ramp-up of Stage 4 was completed. The complex ended 2013 achieving daily production rates of approximately 95% of nameplate capacity of 180 mbbls/d.

- **Hot bitumen infrastructure commissioned.** Suncor initiated a number of debottlenecking projects across Oil Sands operations, including the completion of an insulated bitumen pipeline from Firebag to the Athabasca terminal. Combined with blending facilities at the Athabasca terminal and diluent import capabilities, Suncor increased the takeaway capacity of bitumen and unlocked production in mining.

- **Fort Hills project sanctioned.** In October, Suncor and project co-owners unanimously agreed to proceed with the Fort Hills oil sands mining project. The project is scheduled to produce first oil by the fourth quarter of 2017 and is expected to achieve 90% of its planned production capacity of 180 mbbls/d (73 mbbls/d net to Suncor) within its first year.

- **Libya production shut in.** Export terminal operations at Libyan seaports were closed during the latter half of 2013 due to political unrest in the country. Production was shut in during this period; however, Suncor was able to continue progress on its exploration program.

- **Rail offloading facility complete.** Construction of a rail offloading facility to enable receipt of inland crudes at the Montreal refinery was completed in the fourth quarter of 2013. The Montreal refinery received its first shipment in early December.

- **Successful completion of Upgrader 1 turnaround.** Suncor successfully executed planned maintenance across its operations, including a seven-week turnaround at Upgrader 1, which was the largest turnaround in the company's history. The next scheduled turnaround at Oil Sands operations is in 2016.

2014

- **Market access initiatives.** Crude by rail shipments to the company's Montreal refinery averaged approximately 33 mbbls/d in 2014. In addition, the rail offloading facilities at Tracy, Quebec were used to move crude to new and existing markets. Suncor also started transporting heavy crude on TransCanada's Gulf Coast Pipeline which provided increased access to global-based pricing.

- **Exploration interests in E&P Canada.** In May 2014, Suncor signed a farm-in agreement with Shell Canada to acquire a 20% interest in a deepwater exploration opportunity in the Shelburne Basin, offshore Nova Scotia. In December 2014, Suncor acquired a 30% interest in an exploration licence in the Flemish Pass off the coast of Newfoundland and Labrador and a 50% interest in another exploration licence in the Carson Basin near the Flemish Pass.

- **Joslyn North mining project scaled back.** Although regulatory permits for the Joslyn North mining project have been obtained, in May 2014, Suncor decided, along with the other co-owners, to reduce spending on the Joslyn North mining project and continue engineering work and optimization studies to support the development plan for the project.

- **Investment in water management strategy.** Suncor commissioned a waste water treatment plant, which is expected to increase the reuse and recycling of waste water from Suncor's upgrading operations and reduce freshwater withdrawal. In addition, Suncor, along with its project partners, approved the development of the Water Technology Development Centre (WTDC), which is expected to connect to Suncor's Firebag operations and provide an environment to test water treatment and recycling technologies. The WTDC is scheduled to become operational in early 2017.

- **Reinforced Suncor's focus on core assets.** Consistent with our long-term corporate strategy to focus on core assets, Suncor sold its Wilson Creek assets in E&P Canada, announced the sale of its interest in Pioneer Energy's retail business, and acquired a sulphur recovery facility adjacent to the Montreal refinery.

- **MacKay River debottleneck and process optimization.** Suncor achieved first oil from the MacKay River facility debottleneck project in the third quarter of 2014.

- **First oil from Golden Eagle Area Development (GEAD).** During the fourth quarter, first oil was achieved at the Golden Eagle project, which is anticipated to ramp up to its peak production rate of approximately 18,000 boe/d (net) during 2015.

- **Libya operations shut in.** Production in Libya temporarily resumed in the latter half of 2014. However, political unrest in December of 2014 resulted in the Libya National Oil Company (NOC) declaring force majeure on oil exports from two terminals resulting in the shut in of substantially all of the company's production by the end of the fourth quarter. Consequently, Suncor also declared force majeure for all exploration commitments in Libya on December 14, 2014.

- **Firebag production exceeds nameplate capacity.** Firebag production in 2014 averaged approximately 95% of nameplate capacity of 180 mbbls/d, and greater than 180 mbbls/d in the fourth quarter. Continued infill and new SAGD well pair development allowed Suncor to optimize steam placement into the reservoir.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

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

Oil Sands

Oil Sands Operations – Assets and Operations

Oil Sands Base Operations

Our integrated Oil Sands Base operations, located in the Athabasca oil sands of northeast Alberta, involve numerous activities:

- **Mining and Extraction**

  After overburden is removed, open-pit mining operations use shovels to excavate oil sands bitumen ore, which is trucked to sizers and breaker units that reduce the size of the ore. Next, a slurry of hot water, sand and bitumen is created and delivered via a 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. Coarse tailings produced in this process are placed directly into sand placement areas.

- **Upgrading**

  After the diluted bitumen is transferred to upgrading facilities, the naphtha is removed and recycled to be used again as diluent in extraction processes. Bitumen is upgraded through a coking and distillation process. The upgraded product, referred to as sour SCO, is either sold 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 and other byproducts.

- **Power and Steam Generation and Process Water Use**

  To generate steam for the mining and extraction process, the company uses either a cogeneration unit or coke-fired boilers. Electricity is generated by turbine generators, some of which are part of the Oil Sands Base cogeneration unit, or provided by cogeneration units at Firebag. Process water is used in extraction processes and then recycled.

- **Maintenance**

  In the normal course of operations, Suncor regularly conducts planned maintenance events at its 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. Production may be impacted during the turnaround cycle. 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 soil salvage and replacement, wetlands research, the protection of fish, waterfowl and other wildlife, and re-vegetation.

  The extraction process produces tailings that are a mixture of water, clay, sand and residual bitumen. Suncor has developed a tailings management approach, known as TRO$_{TM}$. TRO$_{TM}$ is expected to accelerate and improve the company's tailings management processes, eliminate the need for new tailings ponds at existing mining operations, and, in the years ahead, reduce the number of tailings ponds presently in operation.

Oil Sands Base Assets

Millennium and North Steepbank

Suncor pioneered the commercial development of the Athabasca oil sands beginning in 1962, achieving first production in 1967. Bitumen is currently mined from the Millennium area, which began production in 2001, and the North Steepbank area, which began production in 2011. During 2014, the company mined approximately 149 million tonnes of bitumen ore (2013 – 151 million tonnes). During 2014, Suncor processed an average of 274 mbbls/d of mined bitumen in its extraction facilities (2013 – 270 mbbls/d).

Upgrading facilities

Suncor's upgrading facilities consist of two upgraders – Upgrader 1, which has a primary upgrading capacity of approximately 110 mbbls/d of SCO, and Upgrader 2, which has a primary upgrading capacity of approximately 240 mbbls/d of SCO. Suncor's secondary upgrading facilities consist of three hydrogen plants, three naphtha hydrotreaters, two gas oil hydrotreaters, one diesel hydrotreater and one kero hydrotreater.

During 2014, Suncor averaged 289 mbbls/d of upgraded (SCO and diesel) production, sourced from bitumen provided by both Oil Sands Base and In Situ operations (2013 – 283 mbbls/d).

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. Suncor undertakes exploratory drilling programs on such leases from time-to-time, as part of its mine replacement projects. Suncor holds a 100% working interest in both Voyageur South and Audet.

In Situ Operations

Suncor's In Situ operations, Firebag and MacKay River, use SAGD technology to produce bitumen from oil sands deposits that are too deep to be mined economically.

- **The SAGD Process**

  SAGD is an enhanced oil recovery technology for producing bitumen. It requires drilling pairs of horizontal wells with one located above the other. To help reduce land disturbance and improve cost efficiency, well pairs are drilled from multi-well pads. Low pressure steam is injected into the upper wellbore to create a high-temperature steam chamber underground. This process reduces the viscosity of the bitumen, allowing heated bitumen and condensed steam to drain into the lower wellbore and flow up to the surface aided by subsurface pumps or circulating gas.

- **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 shipment, In Situ operations blend diluent with the bitumen, or transport it on an insulated pipeline as hot bitumen.

- **Power and Steam Generation**

  To generate steam for operations, the company uses Once Through Steam Generators (OTSGs) or cogeneration units. OTSGs are powered by both purchased natural gas and produced natural gas recovered at central processing facilities. Cogeneration units are energy-efficient systems, which use natural gas combustion to power turbines that generate electricity and steam used in SAGD operations. Excess electricity generation from cogeneration units is used at Oil Sands Base facilities or sold to the power grid.

- **Maintenance and Bitumen 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 experience natural production declines after several years. In an effort to maintain bitumen supply, Suncor drills new wells from existing well pads or constructs new well pads.

In Situ Assets

Firebag

Production from Suncor's Firebag operations commenced in 2004. Suncor's Firebag complex consists of four central processing facilities with a total nameplate capacity of approximately 180 mbbls/d. Actual production from Firebag varies based on steaming and ramp-up periods for new wells, planned and unplanned maintenance, reservoir conditions and other factors.

As at December 31, 2014, Firebag had ten well pads in operation, with 125 SAGD well pairs and 31 infill wells either producing or on initial steam injection. Central processing facilities have been designed to be flexible as to which well pads supply bitumen. Steam generated at the various facilities can be used at multiple well pads. In addition, Firebag includes five cogeneration units that generate steam, which are capable of producing approximately 420 MW of electricity. The Firebag site power load requirements are 110 MW and Suncor exports approximately 310 MW of electricity. There are also 13 OTSGs at the site for additional steam generation.

During 2014, Firebag production averaged 172 mbbls/d (2013 – 143 mbbls/d). During 2014, the SOR at Firebag was 2.8 (2013 – 3.3).

MacKay River

Production from Suncor's MacKay River operations commenced in 2002. As at December 31, 2014, MacKay River included six well pads with 95 well pairs either producing or on initial steam injection. The MacKay River central processing facilities have bitumen processing capacity of approximately 38 mbbls/d. A third party owns the on-site cogeneration unit, which Suncor operates under a commercial agreement that is used to generate steam and electricity. There are also four OTSGs at the site for additional steam generation. The company is in the process of completing further well pad development associated with the MacKay River facility debottleneck project.

During 2014, Mackay River production averaged 27 mbbls/d (2013 – 29 mbbls/d). During 2014, the SOR at MacKay River was 2.9 (2013 – 2.6).

Suncor has regulatory approval to increase bitumen processing capacity by approximately 20,000 mbbls/d with an additional central processing facility at MacKay River

(MacKay River Expansion). However, in January 2015, Suncor deferred the timing of a sanction decision for this project as a result of the current lower crude price environment.

Other In Situ Leases

Suncor owns several other oil sands leases, including those known as Meadow Creek, Lewis, Chard and Kirby, on which it may undertake exploratory drilling. In 2014, Suncor drilled 55 core holes at Lewis and 37 gross core holes at Meadow Creek. Plans for winter 2015 drilling include an additional 100 core holes at Lewis and 68 core holes at Meadow Creek. Suncor holds a 100% working interest in Lewis, 10% working interest in Kirby, 25% to 50% working interest in Chard, and a 75% working interest in Meadow Creek.

Starting with Meadow Creek, Suncor is commencing a greenfield growth plan with a concept to further develop new in situ reservoirs using a replication strategy to build standardized surface facilities, well pads and infrastructure. This will reduce facility capital expenditures. The winter exploratory drilling programs are designed to identify sufficient resources to fill facilities associated with the replication strategy. A development application is anticipated to be filed with the Alberta Energy Regulator (AER) in 2015.

Oil Sands Ventures

Syncrude

Suncor holds a 12% interest in the Syncrude joint arrangement, located near Fort McMurray, which includes mining operations at Mildred Lake North and Aurora North. Syncrude also has regulatory approval to develop the Aurora South oil sands mining leases. In 2012, the Syncrude co-owners announced a plan to develop two mining areas adjacent to the current mine, subject to final sanctioning and regulatory approvals, which would consequently extend the life of Mildred Lake by approximately ten years. The plan proposes to use existing mining and extraction facilities and regulatory applications for these areas were submitted in December 2014.

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 pipeline systems, similar to those at Oil Sands Base. Extraction and upgrading technologies at Syncrude are similar to those used at Oil Sands Base, with the exception that Syncrude uses a fluid coking process that involves the continuous thermal cracking of the heaviest hydrocarbons. At Mildred Lake, electricity is provided by a utility plant fuelled by natural gas and off-gas from upgrading operations. At Aurora North, Syncrude operates two 80-MW gas turbine power plants to provide electricity.

Syncrude produces a single sweet synthetic light crude product. Marketing of this product is the responsibility of the individual co-owners.

Land reclamation activities are similar to those at Oil Sands Base; however, certain aspects of the tailings management processes are different. Syncrude's 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 2014, Suncor's share of Syncrude production averaged 31 mbbls/d (2013 – 32 mbbls/d).

Fort Hills

Fort Hills is an oil sands mining area comprising leases on the east side of the Athabasca River, north of Oil Sands Base operations. Designs for the Fort Hills mining project plan for 180 mbbls/d of bitumen production capacity (gross). Fort Hills will use a paraffinic froth treatment process to provide marketable bitumen product. Suncor originally acquired a 60% working interest in Fort Hills through the merger, but subsequently disposed of 19.2% as part of transactions with Total. Suncor now holds a 40.8% working interest in the Fort Hills project and is the contract operator for the project. The company's share of the post-sanction project costs are estimated to be $5.5 billion. Approximately $1.6 billion of the company's 2015 capital budget has been allocated to this project. Project activities in 2015 are expected to focus on completing detailed engineering on the secondary extraction and utilities areas, the continued ramp up of field construction activities, and procurement spending across all areas. As at December 31, 2014, Suncor had incurred $1.3 billion post-sanction project costs.

Other Assets

Joslyn is an oil sands mining area comprising leases southwest of Fort Hills and on the west side of the Athabasca River. Preliminary designs for the Joslyn North mining project plan for 157 mbbls/d of bitumen production (gross). Suncor acquired a 36.75% working interest in this asset as a result of transactions with Total. Although regulatory permits for the Joslyn North mining project have been obtained, in May 2014, Suncor, together with the other co-owners, agreed to scale back certain development activities in order to focus on engineering studies to further optimize the project development plan.

New Technology

Technology is a fundamental component to Suncor's business. Suncor has pioneered commercial oil sands development and continues to advance technology through innovation and collaboration to improve efficiencies, lower costs and increase environmental performance. Development of new technology can take extended periods of time, first to demonstrate technical viability and then to demonstrate economic viability. The necessary validation typically occurs through a series of progressive tests which allow results to be reliably scaled and assessed for implementation.

Suncor is working on several new in situ technology projects that are proceeding with the next phase of field testing. Examples of Suncor's new technology projects include:

- Oxy-Fuel Combustion – Suncor is involved in a collaborative research and development project that could improve the prospects for implementing carbon capture and storage.
- Zero Liquid Discharge – Suncor uses a zero liquid discharge process at our MacKay River in situ facility to achieve maximum water reuse by recovering waste water from produced bitumen.
- Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH) – This new method of in situ bitumen recovery uses radio frequency heating and solvents to reduce energy, greenhouse gas and water footprints. The second phase of pilot testing is expected to begin in the first quarter of 2015.
- N-SOLV$_{TM}$ – Suncor is currently undertaking field tests on using this condensing solvent to extract bitumen, which could significantly reduce energy use and greenhouse gas emissions. The pilot test is ongoing.
- Steam Assisted Gravity Drainage Less Intensive Technology Enhanced (SAGD LITE) – Field trials are underway to evaluate technologies such as solvent addition, surfactant addition, flow control devices and injection control devices to improve cost, SORs, and timely recovery and productivity.

Suncor is a founding member of Canada's Oil Sands Innovation Alliance (COSIA), a group of oil sands producers focused on accelerating the pace of environmental performance improvement through collaborative action and innovation.

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 and markets in the U.S. Gulf Coast. 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 diluted bitumen at Suncor's Edmonton refinery; or c) selling diluted bitumen directly to third parties. Increased bitumen sales may also be required during upgrading facilities outages. During 2013, Suncor increased the flexibility of marketing In Situ production by completing the construction of the hot bitumen insulated pipeline and the blending facilities at the East Tank Farm, and securing diluent blending stock. In Situ bitumen production processed by Oil Sands Base upgrading facilities in 2014 decreased to 49% or 98 mbbls/d (2013 – 55% or 94 mbbls/d) as more In Situ bitumen was sold directly to market following the commissioning of the hot bitumen infrastructure.

	2014		2013	
Sales Volumes and Operating Revenues – Principal Products	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
Sweet – Light sweet SCO and diesel (including Syncrude)	**161.4**	**44**	147.9	43
Sour – Light sour SCO and bitumen	**260.3**	**52**	241.9	51
Non-proprietary, byproducts and other operating revenues [(1)]	**n/a**	**4**	n/a	6
	421.7		389.8	

(1) Operating revenues include sales of non-proprietary volumes, primarily third-party diluent purchased to support sales of bitumen that is required when the company is unable to meet diluent demands internally, as well as revenues associated with excess power from cogeneration units.

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

Distribution of Products

Production from Oil Sands operations is gathered into Suncor's Fort McMurray facilities at the Athabasca Terminal, which is operated by Enbridge. Suncor has arrangements with Enbridge to store SCO, diluted bitumen and diesel at this facility. Product moves from the Athabasca Terminal in the following ways:

- 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, including Suncor, or transferred onto the Enbridge mainline system or the TransMountain Pipeline system.
- To Cheecham, Alberta on the Enbridge Athabasca Pipeline or the Enbridge Wood Buffalo Pipeline. From Cheecham, the Enbridge Athabasca Pipeline continues to Hardisty, Alberta.
- To Edmonton via the Enbridge Waupisoo Pipeline, originating at Cheecham.

From Hardisty, where Suncor owns storage capacity with additional capacity under contract, the company has various options for delivering product to customers:

- To 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.
- To Suncor's Sarnia refinery on the Enbridge mainline and Lakehead systems.
- To most major refining hubs via the Enbridge mainline, Express/Platte and Keystone pipeline systems.

Royalties

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

Effective January 1, 2009, under the New Royalty Framework, royalties are based on a sliding-scale rate of 25% to 40% of net revenue, subject to a minimum royalty within a range of 1% to 9% of gross revenue. Revenues used in royalty formulas are driven primarily by benchmark prices for WCS, while sliding-scale percentages in royalty formulas depend on 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 revenues exceed its cumulative costs, including an annual investment allowance (the post-payout phase).

Oil Sands Base and Syncrude

As part of the New Royalty Framework, both Suncor and the co-owners of Syncrude reached separate agreements with the Government of Alberta for the implementation of the New Royalty Framework:

- For the period from January 1, 2010 to December 31, 2015, royalty rates for Oil Sands Base are based on a sliding scale, depending on the Canadian dollar equivalent for WTI, from 25% to 30% of net revenue. Oil Sands Base royalties are also subject to the minimum royalty rate range of 1.0% to 1.2% of gross revenue. In 2014, Suncor incurred royalties at Oil Sands Base mining operations at a rate of 30% of net revenue (2013 – 30% of net revenue).
- Syncrude will continue paying the bitumen-based royalty based on the greater of 1% gross revenue, or 25% of net revenue, until December 31, 2015. For 2014, the royalty rate at Syncrude was 25% of net revenue (2013 – 25% of net revenue). In addition, the co-owners of Syncrude 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.

In 2014, Oil Sands Base royalties were approximately 7% of Oil Sands Base operating revenues (2013 – 6%). In 2014, Suncor incurred royalties on Syncrude operations averaging approximately 7% of Syncrude operating revenues (2013 – 6%).

Beginning on January 1, 2016, Suncor's Oil Sands Base and Syncrude operations are expected to be subject to the generic royalty regime as set out in the New Royalty Framework.

In Situ

Royalty rates for Suncor's MacKay River and Firebag are based on the New Royalty Framework.

In 2014, Suncor incurred royalties at an average rate of 7% of gross revenue for MacKay River (2013 – 6% of gross revenue) and royalties at an average rate of 7% of gross revenue for Firebag (2013 – 7% of gross revenue), which continues in the pre-payout phase.

Exploration and Production

E&P Canada – Assets and Operations

East Coast Canada

Based in St. John's, Newfoundland and Labrador, this business includes interests in three producing fields and future developments and extensions. Suncor is also involved in exploration drilling for new opportunities. Suncor is the only company in this region with interests in every field currently in production.

Terra Nova

The Terra Nova oilfield is approximately 350 km southeast of St. John's. Terra Nova was discovered in 1984, and was the second oilfield to be developed offshore Newfoundland and Labrador. Operated by Suncor, the production system uses a FPSO vessel that is moored on location, and has gross production capacity of 180 mbbls/d (68 mbbls/d net to Suncor) and oil storage capacity of 960 mbbls. Terra Nova was the first harsh environment development in North America to use a FPSO vessel. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. The Terra Nova oilfield is divided into three distinct areas, known as the Graben, the East Flank and the Far East. Production from Terra Nova began in January 2002. As at December 31, 2014, there were 30 wells: 17 oil production wells, ten water injection wells and three gas injection wells. In 2014, Suncor's share of Terra Nova production averaged 17 mbbls/d compared to 14 mbbls/d in 2013. Annual turnaround maintenance was completed at the Terra Nova facility in August 2014 which lasted four weeks.

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., an ExxonMobil-managed company, the production system is a fixed GBS that sits on the ocean floor, and has gross production capacity of 230 mbbls/d (46 mbbls/d net to Suncor) and oil storage capacity of 1,300 mbbls. Actual production levels are lower, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. Hibernia commenced production in November 1997. As at December 31, 2014, there were 63 wells: 37 oil production wells, 14 single-zone water injection wells, seven dual-zone water injection wells and five gas injection wells. In 2014, Suncor's share of Hibernia production averaged 23 mbbls/d (2013 – 27 mbbls/d).

In 2010, final agreements were signed between the Hibernia co-venturers and the Government of Newfoundland and Labrador that established the fiscal, equity and operational principles for the development of the HSEU. Three development wells have been completed from the GBS platform and are producing oil. Subsea infrastructure was installed in late 2013 and drilling activities continued through 2014. Current development plans include drilling two additional development wells from the GBS platform and five additional water injection wells in the excavated subsea drill centre. The number of development and injection wells required may be revised as the development proceeds and uncertainties regarding reservoir capability are resolved. Production from the HSEU is expected to reach higher rates in 2015 when several planned water injection wells are completed.

White Rose and the White Rose Extensions

White Rose is approximately 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 mbbls/d (39 mbbls/d net to Suncor) and oil storage capacity of 940 mbbls. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. Production from White Rose began in November 2005. As at December 31, 2014, there were 34 wells: 15 oil production wells, 15 water injection wells, one gas injection well and three gas storage wells. In 2014, Suncor's share of White Rose production averaged 15 mbbls/d (2013 – 15 mbbls/d).

In 2007, the White Rose co-venturers signed an agreement with the Government of Newfoundland and Labrador for the development of the White Rose Extensions, which include the North Amethyst, South White Rose Extension, and West White Rose satellite fields. In May 2010, first oil was achieved in North Amethyst, and development drilling is ongoing. Development of the South White Rose Extension began in 2013 with the installation of subsea gas injection infrastructure. Oil production and water injection infrastructure were installed in 2014; drilling began in 2014 and is expected to continue in 2015 with first oil anticipated in the second quarter of 2015.

Development of the West White Rose field has been divided into two stages. The first stage was approved in 2010 and first oil was achieved in 2011. In late 2014, sanction of the second stage was deferred by the co-owners of the project in light of the current lower crude price environment.

Hebron

Discovered in 1980, the Hebron oilfield is located 340 km southeast of St. John's. The project is operated by

ExxonMobil Canada Properties. On December 31, 2012, the Hebron co-owners announced project sanction. Development of the Hebron project includes the construction of a concrete GBS that supports an integrated topsides deck to be used for production, drilling and accommodations. Development plans include 1,200 mbbls of oil storage capacity and 52 well slots with a gross oil production capacity of 150 mbbls/d (34 mbbls/d net to Suncor). Construction of the GBS and topside progressed according to plan during 2014. The GBS was successfully moved from dry dock into its deepwater construction site in the third quarter of 2014. First oil is expected in 2017. Suncor's share of the post-sanction project cost estimate provided by the project operator is approximately $2.8 billion.

Other Assets

The Ballicatters discovery, located 22 km northeast of Hibernia, was completed in 2011 and is comprised of gas and oil. The licence is operated by Suncor. In September 2013, the Canada-Newfoundland and Labrador Offshore Petroleum Board issued two Significant Discovery Licences (SDL 1051 and SDL 1052) for the Ballicatters discovery. Options to commercialize the discovery are currently being evaluated.

During 2014, Suncor entered into an agreement with Shell Canada Limited and ConocoPhillips Canada East Coast Partnership to pursue a deepwater exploration opportunity in the Shelburne Basin, located approximately 250 km offshore Nova Scotia. Through the agreement, Suncor acquired a 20% non-operating interest. Current plans are to proceed with two exploration wells commencing in 2015.

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. During the fourth quarter of 2014, Suncor was a successful joint bidder with ExxonMobil Canada for exploration licences in the Flemish Pass and Carson Basin, located approximately 500 km off the east coast of Newfoundland. The work commitment on these licences in the Flemish Pass and Carson Basin is over the next six to nine years, with no significant spend planned in 2015. The company also holds interests in 50 other significant discovery licences and 12 other exploration licences offshore in this area.

North America Onshore

The North America Onshore business explores for, develops and produces natural gas, NGLs, crude oil and byproducts in Western Canada. Suncor sold the majority of its natural gas business in 2013 followed by the sale in 2014 of its interests in its Wilson Creek assets in central Alberta for $168.5 million before closing adjustments and other closing costs. Following these disposals, the retained assets produce approximately 4 mboe/d, primarily natural gas, from the Kobes/Montney assets in northeast B.C., in which Suncor has a 100% working interest.

Suncor also holds undeveloped assets that allow the company to explore long-term opportunities.

E&P International – Assets and Operations

North Sea

Buzzard

The Buzzard oilfield is located in the Outer Moray Firth, 95 km northeast of Aberdeen, Scotland. Operated by Nexen Petroleum U.K. Limited (Nexen U.K.), a subsidiary of China National Offshore Oil Corporation Limited, the Buzzard facilities have gross installed production capacity of approximately 220 mbbls/d (66 mbbls/d net to Suncor) of oil and 80 mmcf/d (24 mmcf/d net to Suncor) of natural gas. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, water injection limits, gas and water production limits, and asset and infrastructure reliability. 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. As at December 31, 2014, there were 48 wells: 35 oil and gas production wells and 13 water injection wells. In 2014, Suncor's share of Buzzard production averaged 47 mboe/d (2013 – 56 mboe/d).

In 2014, Buzzard completed two oil development wells.

Golden Eagle

The Golden Eagle development operated by Nexen U.K. is approximately 20 km north of the Buzzard oilfield and consists of the unitization of the Peregrine, Hobby, Golden Eagle and Solitaire areas. During 2011, the Golden Eagle project was sanctioned. The development incorporates a production, utilities and accommodation platform, linked to a separate wellhead platform, with a peak production rate of 70 mbbls/d (18 mbbls/d net to Suncor) from 21 development wells. The estimated gross development cost will be £2 billion (Cdn$3.3 billion) or £0.6 billion (Cdn$1.0 billion) net to Suncor, based on sanction date cost estimates and exchange rates. In 2014, activities included the transportation and installation of the processing utilities and quarters deck. Drilling of development wells commenced in March 2014 and will continue through 2015 as the project ramps up to planned capacity. First oil was achieved on October 30, 2014. In 2014, Suncor's share of GEAD production averaged 0.6 mbbls/d. The Golden Eagle co-owners also hold adjacent exploration licences and continue to explore the region.

Other Assets

Other Suncor exploration and appraisal initiatives in the North Sea include:

- Beta discovery (Norway) – Suncor is the operator for the PL375, PL375b and PL375c licences, in which it has an 80% interest. The company drilled the first exploration well in early 2010, encountering hydrocarbons. An appraisal well was drilled and tested later in 2010 with positive results. However, a third well drilled into a separate fault block did not encounter hydrocarbons. The company will continue to evaluate the Beta discovery by interpreting 3D seismic data acquired in 2013, with further drilling starting in 2015. The Beta licences also contain other exploration opportunities.

- Butch discovery (Norway) – In 2011, Centrica plc, the operator for the PL405 licence in which Suncor has a 30% interest, drilled an exploration well resulting in a discovery, followed by a sidetrack well to assess the lateral extent of the hydrocarbons. Early in 2012, a second sidetrack well was attempted but abandoned, due to well instability, before reaching its intended depth. In 2014, two additional wells were drilled to explore for oil in separate fault blocks from the discovery, but did not encounter hydrocarbons.

- Lily prospect (U.K.) – In 2013, the operator for the P928 20/1S licence, in which Suncor has a 29.89% interest, drilled an exploration well, which was completed in the first quarter of 2014, but did not encounter hydrocarbons.

- Blackjack prospect (U.K.) – During the first half of 2014, the operator of the P300 14/26a licence, in which Suncor has a 26.69% interest, drilled an exploration well. The well did encounter hydrocarbons, but following evaluation, it was determined to be non-commercial.

Suncor continues to pursue other opportunities in the North Sea, the Norwegian Sea and the Barents Sea. The company holds interests in 27 exploration licences in the U.K. and Norwegian sectors of these areas.

Other International

Libya

In Libya, Suncor is signatory to seven EPSAs with the NOC. Five of the seven EPSAs contain producing fields and exploration prospects; the remaining two are exploration EPSAs that do not contain producing fields, one of which is being relinquished because the exploration program was not successful. Under the EPSAs, Suncor pays 100% of the exploration costs, 50% of the development costs and 12% of the operating costs. The development, operating and eligible exploration costs are recovered through a 12% share of production (Cost Recovery oil). Any Cost Recovery oil remaining after Suncor's costs have been recovered is referred to as excess petroleum, and is shared between Suncor and the NOC based on several factors. The EPSAs expire on December 31, 2032, but include an initial five-year extension through the end of 2037. 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.

From March to September 2011, the operator for the joint operation, Harouge Oil Operations BV, shut in production as a result of political unrest. By early 2012, production had restarted in all major producing fields. In July 2013, production was shut in again as political unrest resulted in the closure of seaport terminals. Production remained shut in until July 2014, when the last two affected terminals were reopened and production slowly began to resume. However, in December 2014, operations in Libya were again disrupted as political unrest continued, resulting in the closure of two of the main seaport terminals and, as a result, substantially all of Suncor's production was again shut in. The region remains volatile and Suncor's ability to return to continued and normal production levels remains uncertain. The estimated cost of Suncor's remaining exploration work program commitment at December 31, 2014, is US$359 million.

In 2014, Suncor's share of production in Libya averaged 7 mbbls/d (2013 – 21 mbbls/d).

Syria

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. Consequently, the company has ceased recording all production and revenue associated with its Syrian assets. Since 2011, Suncor has not been able to monitor the status of any of its assets in the country, including whether certain facilities have suffered damage. As a result of continued uncertainty about Suncor's future in the country, the remaining value of the Suncor assets was impaired in 2013.

Suncor conducts its Syrian operations pursuant to a PSC, where the company pays 100% of the development costs and recovers these costs from a 40% share of production after deduction of 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 General Petroleum Corporation (GPC) and the remaining 50% is shared between Suncor and the GPC according to a profit-sharing schedule.

Sales of Principal Products

Oil and gas production from East Coast Canada, the North Sea and from North America Onshore is either marketed by our Energy Trading business, acting as a marketing agent, or sold to our Energy Trading business, which then markets the products to customers under direct sales 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 all made on a spot basis, and incorporate pricing that is generally determined on a daily or monthly basis in relation to a specified market reference price.

In Libya, crude oil is marketed by the NOC on behalf of Suncor.

Exploration and Production Sales Summary:

Sales Volumes	2014 mboe/d	2014 % operating revenues	2013 mboe/d	2013 % operating revenues
E&P Canada				
Crude oil and NGLs	**55.2**	**53**	61.2	43
Natural gas	**2.8**	**1**	32.0	4
E&P International				
Crude oil and NGLs	**47.2**	**46**	75.2	53
Natural gas	**0.9**	**0**	1.2	0
Total Exploration and Production				
Crude oil and NGLs	**102.4**	**99**	136.4	96
Natural gas	**3.7**	**1**	33.2	4

Distribution of Products

- East Coast Canada – 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, the U.S., Europe, Latin America and Asia. 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.
- North America Onshore – gas production from B.C. is typically sold at Station 2, part of the Spectra B.C. transmission system. Suncor also holds firm capacity on the TransCanada PipeLines Gas Transmission Northwest Pipeline, which enables Suncor to deliver natural gas to the Pacific Northwest and California markets.
- Buzzard – crude oil is transported via the third-party operated Forties Pipeline System to the Hound Point terminal in Scotland and sold as part of the Forties Blend crude stream. Natural gas is transported via the third-party operated Frigg Pipeline System to the St. Fergus Gas Terminal in Scotland.
- Golden Eagle – crude oil is transported to the third-party operated Flotta Terminal in the Orkney Islands in Scotland where it is shipped to market as part of the Flotta Gold blend.

Royalties

East Coast Canada

The Terra Nova royalty consists of a sliding-scale basic royalty payable, with two tiers of incremental royalties. The basic royalty is now capped at 10% of gross field revenue. 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 an additional 12.5% of net revenue, became payable in 2008. During 2014, Terra Nova royalties averaged 21% of gross revenue (2013 – 12% of gross revenue).

The Hibernia royalty agreement for production from the original oilfields and the AA Block consists of a sliding-scale basic royalty, two tiers of incremental royalties, and an additional net profits interest (NPI). The basic royalty is now capped at 5% of gross revenue. The tier one royalty, which became payable in 2009, is the greater of the basic royalty or 30% of net revenue. The tier two royalty is an additional 12.5% of net revenue, but has not yet been triggered. Production from the AA Block, which commenced in late 2009, attracts an additional tier three 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 tier three royalty that ranges between 2.5% and 7.5% of net revenue, depending on the price for WTI. The HSEU tier three royalty will coincide with the triggering of the tier one royalty. For that portion of the HSEU that is contained within the original Hibernia licence area, but will be developed with the new subsea facilities, production will be subject to an additional tier three royalty that ranges between 7.5% and 12.5% of net revenue, depending on the price for WTI. During 2014, Hibernia (including the HSEU) royalties and NPI combined to average 33% of gross revenue (2013 – 36% of gross revenue).

The White Rose royalty for the base project consists of a sliding-scale basic royalty, with two tiers of incremental

royalties. The basic royalty is now capped at 7.5% of gross field revenue. The tier one royalty is the greater of the basic royalty or 20% of net revenue and became payable in 2007. The tier two royalty, equal to an additional 10% of net revenue, became payable in 2008. The royalty for production from the White Rose Extensions is similar to the base project, except that there is an additional tier three royalty, equal to 6.5% of net revenue, which is payable if WTI is greater than US$50/bbl. Tier one and tier three royalties for White Rose Extensions became payable in 2014. During 2014, total White Rose royalties averaged 14% of gross revenue (2013 – 16%).

E&P 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. The U.K. Government has announced that this will be reduced to 60% effective January 1, 2015. The reduction is expected to be substantively enacted in the first half of 2015. For operations in Libya, all government interests, except for income taxes, are presented as royalties.

Refining and Marketing

Refining and Supply – Assets and Operations

Eastern North America

Montreal Refinery

The Montreal refinery has a crude oil capacity of 137 mbbls/d, processing primarily conventional crude oil, with a flexible configuration that allows processing of light, sour and heavy grades of crude oil, as well as intermediate feedstock. 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 supplied via the Portland-Montreal Pipeline, by marine transportation and by rail for inland crudes. The Montreal refinery received inland crude volumes averaging 33 mbbls/d through 2014.

Production yield from the Montreal refinery includes gasoline, distillate, heavy fuel oil, solvents, asphalt and petrochemicals, which are distributed primarily across Quebec and Ontario. The Montreal refinery also produces feedstock for Suncor's 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.

In 2014, Suncor completed the acquisition of a sulphur recovery plant that is now integrated with the Montreal refinery's operations and is expected to secure the refinery's long-term sulphur recovery needs.

Sarnia Refinery

The Sarnia refinery has a crude oil capacity of 85 mbbls/d, processing both SCO from 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 mainline and Lakehead pipeline systems. Suncor procures conventional crude oil feedstock primarily from Western Canada and has the ability to supplement supply with purchases from the U.S.

Production yield from the Sarnia refinery includes gasoline, kerosene, and jet and diesel fuels, 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 products into the U.S.

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

Other Facilities

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 paraxylene, which is used by customers to manufacture polyester textiles and plastic bottles. Paraxylene production was approximately 366,000 metric tonnes in 2014 (2013 – 355,000 metric tonnes). 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, located in Mississauga, Ontario, is the largest producer of lubricant base stocks in Canada. In 2014, the plant produced approximately 844 million litres of lubricant base stocks. Feedstock for the lubricants facility comes from Suncor's Montreal refinery and other purchase contracts.

Western North America

Edmonton Refinery

The Edmonton refinery has a crude oil capacity of 142 mbbls/d and has the potential to run entirely on feedstock sourced from oil sands. Crude oil is supplied to the refinery via company-owned and third-party pipelines.

Feedstock is supplied from Suncor's Oil Sands operations, Syncrude operations (including volumes purchased by Suncor from other co-owners' share of production) and other producers from the Wood Buffalo and Cold Lake regions of Alberta. The refinery can process approximately 41 mbbls/d of blended feedstock (comprised of 29 mbbls/d of bitumen and 12 mbbls/d of diluent) and process approximately 44 mbbls/d of sour SCO. The refinery can also process approximately 57 mbbls/d of sweet SCO through its synthetic train.

Production yield from the Edmonton refinery includes primarily gasoline, distillate and other light oils, 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.

Commerce City Refinery

The Commerce City refinery has a crude oil capacity of 98 mbbls/d. The refinery processes primarily conventional crude oil, but also has the capability of processing up to 16 mbbls/d of sour SCO and diluted bitumen 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 61% 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, distillate and paving-grade asphalt. The majority of the refined products 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.

Other Facilities

To support the supply and demand balance in the Vancouver area, Suncor imports and exports finished products through its Burrard distribution terminal located on the west coast of B.C. 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 tables summarize the crude feedstock, utilizations and production yield mix for Suncor's refineries for the years ended December 31, 2014 and 2013. Refinery utilizations include the impacts of planned and unplanned maintenance events.

Average Daily Crude Throughput	Montreal		Sarnia		Edmonton		Commerce City	
(mbbls/d, except as noted)	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Oil Sands Base sweet synthetic	**—**	—	**11.5**	28.0	**41.3**	45.5	**0.6**	—
Oil Sands Base sour synthetic	**—**	—	**24.1**	11.3	**63.2**	59.3	**10.8**	8.0
Other synthetic	**—**	—	**15.4**	11.6	**26.8**	23.6	**8.7**	8.9
East Coast Canada light conventional[(1)]	**23.2**	14.6	**—**	—	**—**	—	**—**	—
Other light conventional	**79.4**	94.2	**5.0**	24.8	**—**	0.5	**65.8**	72.1
Sour conventional	**4.9**	0.2	**19.8**	—	**—**	—	**11.0**	11.3
Heavy conventional	**15.6**	16.7	**—**	—	**—**	—	**—**	—
Total	**123.1**	125.7	**75.8**	75.7	**131.3**	128.9	**96.9**	100.3
Utilization[(2)] (%)	**90**	92	**89**	89	**92**	92	**99**	102

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

(2) Refinery utilizations based on crude 2014 processing capacities (in mbbls/d): Montreal – 137; Sarnia – 85; Edmonton – 142; and Commerce City – 98. Edmonton processing capacity was 140 mbbl/d in 2013; the utilization rate has not been restated.

Refined petroleum production yield mix (%)	Montreal		Sarnia		Edmonton		Commerce City	
	2014	2013	2014	2013	2014	2013	2014	2013
Gasoline	**42**	41	**47**	39	**41**	43	**47**	49
Distillates	**35**	37	**34**	46	**54**	52	**35**	35
Other	**23**	22	**19**	15	**5**	5	**18**	16

Distribution Terminals and Pipelines

Suncor owns and operates 13 major refined product terminals across Canada (including terminals adjacent to refineries) 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 the Refining and Marketing segment's current storage and distribution needs.

Suncor has ownership interests in certain pipelines, including the following:

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, Wyoming

Marketing – Assets and Operations

Suncor's retail service station network operates nationally in Canada primarily under the Petro-Canada $_{TM}$ brand. As at December 31, 2014, this network consisted of 1,465 outlets across Canada, excluding Pioneer retail locations. In addition, refined products are marketed through independent dealers and joint arrangements. Suncor's Canadian retail network had annual sales of gasoline motor fuels averaging approximately 4.8 million litres per site in 2014 (2013 – 4.8 million litres) and attracted an estimated 17.3% share (2013 – 17.7%) of the national retail urban market.

Suncor's Colorado retail network consists of 44 owned outlets and product supply agreements with a larger network of Shell®-branded sites and Phillips 66®-branded sites in Colorado.

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

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

Retail Summary:

Locations	As at December 31 2014	2013
Retail Service Stations – Canada		
Petro-Canada$_{TM}$-branded	**1 465**	1 454
Sunoco$_{TM}$-branded	**1**	7
	1 466	1 461
Retail Service Stations – Colorado		
Shell®-branded retail service stations	**38**	38
Phillips 66®-branded retail service stations	**6**	6
	44	44
Wholesale Cardlock Sites – Canada		
Petro-Canada$_{TM}$-branded cardlock sites (PETRO-PASS)	**266**	259

Sales Volumes	2014 mbbls/d	2014 % operating revenues	2013 mbbls/d	2013 % operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	**117.0**		116.0	
Western North America	**118.6**		131.4	
	235.6	**44**	247.4	47
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	**107.2**		89.1	
Western North America	**100.3**		120.7	
	207.5	**39**	209.8	39
Other (includes heavy fuel oil, asphalts, lubricants, petrochemicals, other)				
Eastern North America	**58.2**		57.0	
Western North America	**30.4**		28.6	
	88.6	**17**	85.6	14
	531.7		542.8	

Sales volumes for specific products are moderately 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 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 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, and the Sarnia and Montreal refineries. In addition, Suncor may purchase refined products from third-party suppliers.

Other Suncor Businesses

Energy Trading

Suncor's Energy Trading business is organized around five main commodity groups – crude oil, natural gas, sulphur, petroleum coke and electricity – and has trading offices in

Canada, the U.K. and the U.S. Energy Trading provides commodity supply, transportation, storage and pricing solutions. Our customers include mid- to large-sized commercial and industrial consumers, utility companies and energy producers.

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

The Energy Trading business commenced rail shipments through two rail offload facilities in 2014. The Montreal, Quebec facility was operational throughout 2014 and is used to provide non-proprietary inland crude to the Montreal refinery. The company also secured a new offloading agreement at a rail terminal in Tracy, Quebec, which became operational in the third quarter of 2014 and allowed access to eastern tidewaters for non-proprietary products.

The Energy Trading business supports the company's Refining and Marketing business by optimizing the supply of crude and NGLs feedstock to the four refineries, managing crude inventory levels during refinery turnarounds and periods of unplanned maintenance as well as managing external impacts from pipeline disruptions.

Renewable Energy

Since 2006, Suncor has invested in Canada's biofuels industry. Suncor operates Canada's largest ethanol facility, the St. Clair Ethanol plant in the Sarnia-Lambton region of Ontario. The ethanol plant has a nameplate capacity of 400 million litres per year. In 2014, the plant produced 412.0 million litres of ethanol (2013 – 415.0 million litres). In 2014, Suncor also invested in biodiesel technology to capture a production cost advantage, through interests in both a technology company and the retrofit of a biodiesel plant, which is scheduled to be completed by the end of 2015.

In addition, Suncor's renewable energy interests include six wind power projects in operation, as well as the Adelaide wind farm that was completed in 2014. Including Adelaide, Suncor's wind farms have a gross generating capacity of 295 MW. Suncor continues to evaluate new opportunities to build its renewable energy portfolio with potential wind power project sites that are in various stages of the evaluation process.

An eighth wind farm, the Cedar Point project, has received regulatory approval. An appeal of this permit is currently in progress. Suncor expects a final decision on that appeal to be made in March 2015. Detailed engineering is concluding and construction is expected to be completed in 2015. The project is expected to add 100 MW of gross generating capacity.

Suncor's wind power projects:

Wind Power Projects		Ownership Interest (%)	Size (MW)	Turbines	Completed
Operated by Suncor					
Wintering Hills	Drumheller, Alberta	70.0	88	55	2011
Kent Breeze	Thamesville, Ontario	100.0	20	8	2011
Adelaide	Strathroy, Ontario	75.0	40	18	2014
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

SUNCOR EMPLOYEES

The following table shows the distribution of employees among Suncor's business units and corporate office.

As of December 31	**2014**	2013
Oil Sands	**6 098**	6 310
Exploration and Production	**505**	479
Refining and Marketing	**3 528**	3 265
Corporate, Energy Trading and Renewable Energy	**3 849**	3 892
Total	**13 980**	13 946

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 34% of the company's employees were covered by collective agreements at the end of 2014. The majority of collective agreements, covering approximately 4,225 employees, were renewed in 2013 for a 3-year term. The collective agreement with Unifor covering approximately 70 employees on Terra Nova was successfully renewed in January 2015. Collective agreements with the United Steel Workers Union, representing approximately 265 employees at the Commerce City refinery, and with the Sunoco Employees' Bargaining Association, representing approximately 200 employees at the Sarnia refinery, will expire January 31, 2015 and February 28, 2015, respectively. Suncor is currently in negotiations to renew the collective agreements at Commerce City refinery and Sarnia refinery.

SOCIAL AND ENVIRONMENTAL POLICIES

Suncor has a Standards of Business Conduct Code (the Code), which applies to Suncor's directors, officers, employees and contract workers. 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, harassment, 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 or confirmation that any instance of non-compliance has been discussed and resolved with the individual's supervisor. Compliance is then reported to Suncor's Audit Committee. A copy of the Code is available on Suncor's website at www.suncor.com.

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 international human rights principles, such as those described in the Universal Declaration of 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. 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, building stronger communities and supporting shared learning.

Suncor has a Canadian Aboriginal Relations Policy, which affirms Suncor's desire to work in collaboration with Aboriginal Peoples to develop a thriving energy industry that allows Aboriginal communities to be vibrant, diversified and sustainable. The policy provides a consistent approach to the company's relationships with Aboriginal Peoples and outlines Suncor's responsibilities and commitments, and is intended to guide Suncor's business decisions on a day-to-day basis. Suncor is committed to working closely with Aboriginal Peoples and communities to build and maintain effective, long-term and mutually beneficial relationships. The policy makes it clear that responsible development takes into account Aboriginal interests regarding the opportunities and impacts of energy development on communities and on 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 reflects Suncor's belief 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 are 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.

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 EH&S. The committee also reviews the effectiveness with which Suncor establishes appropriate EH&S policies, including environmental performance, given legal, industry and community standards. Management systems are maintained by this committee to implement such policies and ensure compliance.

To support and highlight the goals of the EH&S policy, Suncor holds an Annual President's Operational Excellence Awards, which honours employees and contractors who demonstrate an exceptional commitment to environment, health and safety performance. The awards ceremony highlights progress on safety initiatives and provides educational opportunities for all employees.

The aforementioned policies are reviewed annually and are accessible to employees and contract workers on the company's intranet. Additional workshops and training sessions are also conducted as warranted throughout the year. In addition, information regarding the policies is provided for employees primarily though feature articles on the company's intranet or employee newsletter. The Aboriginal Relations Policy has Cree and Dene audio translations. Training is provided for employees and contract workers whose roles require interaction with Aboriginal communities.

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 February 26, 2015, with an effective date of December 31, 2014. The preparation date of the information is as of February 20, 2015.

Disclosure of Reserves Data

Suncor is subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of reserves data 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 and In Situ operations is based upon evaluations conducted by GLJ Petroleum Consultants Ltd. (GLJ), 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 assets offshore Newfoundland and Labrador and its natural gas assets located in Western Canada (collectively, E&P Canada), and conventional assets offshore the U.K. (North Sea) and in Libya (Other International), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule), 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.

The reserves data summarizes Suncor's SCO, bitumen, light and medium oil, natural gas and NGLs reserves and the net present values of future net revenues for these reserves using forecast prices and costs prior to provision for interest, general and administrative expense, and certain abandonment and reclamation costs.

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, natural gas and NGLs reserves provided herein will be recovered. Actual SCO, bitumen, light and medium oil, natural gas and NGLs 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 Best Estimate Contingent Resources and Notes to Future Net Revenues Tables discussion in conjunction with the following notes and tables.

Significant Risk Factors and Uncertainties Affecting Reserves and Resources Data

The evaluation of reserves and resources 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 and reservoir fluid properties are obtained through seismic programs, drilling programs, updated reservoir performance studies and analysis, and production history, and may result in revisions to reserves. Pricing, market availability and economic conditions affect the profitability of reserves or resources exploitation. For example, depending on the current business environment, higher commodity prices may result in higher reserves by making more projects economically viable or extending their economic life, while lower commodity prices may result in lower reserves (however, this is generally not the case for assets under PSCs, as described in the Notes to Reserves Data Tables in relation to the economic interest method used to determine entitlement reserves). Regulatory changes, including royalty regimes and environmental regulations, cannot be predicted but may have positive or negative effects on reserves. Future technology improvements would be expected to have a favourable impact on the economics of reserves development and exploitation, and therefore may result in an increase to reserves.

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

The reserves and contingent resources estimates included in this AIF represent estimates only. There are numerous uncertainties inherent in estimating quantities and quality of these reserves and contingent resources, including many factors beyond our control. In general, estimates of economically recoverable reserves and the future net cash flow from these assets are based upon a number of variable factors and assumptions, such as production forecasts, the assumed effects of regulation by governmental agencies, pricing assumptions, the timing and amount of capital expenditures, future royalties, future operating costs, project cancellation, and yield rates for upgraded production of synthetic crude oil from bitumen – all of which may vary considerably from actual results. The accuracy of any reserves and resources estimates is a matter of interpretation and judgment and is a function of the quality and quantity of available data, which may have been gathered over time. For these reasons, estimates of the economically recoverable reserves and resources

attributable to any particular group of properties, and classification of such reserves and resources based on the risk of recovery, prepared by different engineers or by the same engineers at different times, may vary.

Reserves and resources estimates are based upon a geological assessment, including drilling and laboratory tests. Mining reserves and resources estimates also consider production capacity and upgrading yields, mine plans, operating life and regulatory constraints. In Situ reserves and resources estimates are also based upon the testing of core samples and seismic operations and demonstrated commercial success of in situ processes. Our actual production, revenues, royalties, taxes, and development and operating expenditures with respect to our reserves will vary from such estimates, and such variances could be material. Production performance subsequent to the date of the estimate may justify revision, either upward or downward, if material.

The reserves evaluations are based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flow to be derived from the reserves contained in the reserves evaluations will be reduced to the extent that such activities do not achieve the level of success assumed in the reserves evaluations.

The reserves evaluations are effective as of a specific effective date and have not been updated, and thus do not reflect changes in our reserves, since that date.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves [1][2][3]
as at December 31, 2014
(forecast prices and costs)

	SCO[4] (mmbbls)		Bitumen (mmbbls)		Light & Medium Oil (mmbbls)		Natural Gas[5] (bcfe)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing										
Mining	1 792	1 589	—	—	—	—	—	—	1 792	1 589
In Situ	159	151	138	127	—	—	—	—	297	278
E&P Canada	—	—	—	—	58	43	38	30	65	48
Total Canada	1 951	1 740	138	127	58	43	38	30	2 154	1 916
North Sea	—	—	—	—	71	71	2	2	72	72
Other International	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Producing	**1 951**	**1 740**	**138**	**127**	**130**	**115**	**40**	**32**	**2 226**	**1 988**
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	7	5	26	25	—	—	—	—	33	29
E&P Canada	—	—	—	—	—	—	12	9	2	1
Total Canada	7	5	26	25	—	—	12	9	35	31
North Sea	—	—	—	—	3	3	—	—	3	3
Other International	—	—	—	—	140	49	—	—	140	49
Total Proved Developed Non-Producing	**7**	**5**	**26**	**25**	**143**	**52**	**12**	**9**	**178**	**83**
Proved Undeveloped										
Mining	—	—	845	734	—	—	—	—	845	734
In Situ	532	447	830	704	—	—	—	—	1 362	1 150
E&P Canada	—	—	—	—	52	48	—	—	52	48
Total Canada	532	447	1 674	1 437	52	48	—	—	2 258	1 932
North Sea	—	—	—	—	16	16	1	1	16	16
Other International	—	—	—	—	2	1	—	—	2	1
Total Proved Undeveloped	**532**	**447**	**1 674**	**1 437**	**70**	**65**	**1**	**1**	**2 277**	**1 949**
Proved										
Mining	1 792	1 589	845	734	—	—	—	—	2 637	2 323
In Situ	698	603	994	855	—	—	—	—	1 692	1 458
E&P Canada	—	—	—	—	110	91	50	39	119	98
Total Canada	2 491	2 192	1 838	1 589	110	91	50	39	4 447	3 879
North Sea	—	—	—	—	91	91	3	3	91	91
Other International	—	—	—	—	142	49	—	—	142	49
Total Proved	**2 491**	**2 192**	**1 838**	**1 589**	**343**	**231**	**53**	**42**	**4 681**	**4 019**
Probable										
Mining	498	429	408	333	—	—	—	—	907	762
In Situ	1 156	940	329	241	—	—	—	—	1 485	1 182
E&P Canada	—	—	—	—	230	167	18	14	233	169
Total Canada	1 655	1 369	737	574	230	167	18	14	2 624	2 113
North Sea	—	—	—	—	37	37	2	2	38	38
Other International	—	—	—	—	111	42	—	—	111	42
Total Probable	**1 655**	**1 369**	**737**	**574**	**378**	**246**	**20**	**16**	**2 773**	**2 192**
Proved Plus Probable										
Mining	2 291	2 018	1 253	1 066	—	—	—	—	3 543	3 085
In Situ	1 854	1 543	1 322	1 097	—	—	—	—	3 177	2 639
E&P Canada	—	—	—	—	340	258	68	52	351	267
Total Canada	4 145	3 561	2 575	2 163	340	258	68	52	7 071	5 991
North Sea	—	—	—	—	128	128	5	5	129	129
Other International	—	—	—	—	253	91	—	—	253	91
Total Proved Plus Probable	**4 145**	**3 561**	**2 575**	**2 163**	**721**	**477**	**73**	**58**	**7 454**	**6 211**

Please see Notes (1) through (5) 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, 2014
(forecast prices and costs)

	SCO[4]			Bitumen			Light & Medium Oil			Natural Gas[5]			Total		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe	mmboe
Mining															
December 31, 2013	1 863	520	2 382	845	397	1 241	—	—	—	—	—	—	2 707	916	3 624
Extensions & Improved Recovery[6]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[7]	18	(21)	(3)	—	12	12	—	—	—	—	—	—	18	(10)	9
Discoveries[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(89)	—	(89)	—	—	—	—	—	—	—	—	—	(89)	—	(89)
December 31, 2014	**1 792**	**498**	**2 291**	**845**	**408**	**1 253**	**—**	**—**	**—**	**—**	**—**	**—**	**2 637**	**907**	**3 543**
In Situ															
December 31, 2013	715	1 092	1 807	1 043	457	1 500	—	—	—	—	—	—	1 758	1 550	3 307
Extensions & Improved Recovery[6]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[7]	8	64	72	(7)	(129)	(136)	—	—	—	—	—	—	2	(65)	(63)
Discoveries[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(25)	—	(25)	(42)	—	(42)	—	—	—	—	—	—	(67)	—	(67)
December 31, 2014	**698**	**1 156**	**1 854**	**994**	**329**	**1 322**	**—**	**—**	**—**	**—**	**—**	**—**	**1 692**	**1 485**	**3 177**
E&P Canada															
December 31, 2013	—	—	—	—	—	—	70	281	351	57	41	97	79	288	367
Extensions & Improved Recovery[6]	—	—	—	—	—	—	1	10	11	10	2	12	2	10	13
Technical Revisions[7]	—	—	—	—	—	—	61	(59)	2	11	(15)	(3)	63	(62)	2

Discoveries[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	(3)	(2)	(5)	(19)	(10)	(29)	(6)	(4)	(10)
Economic Factors[9]	—	—	—	—	—	—	—	—	—	(2)	(1)	(2)	—	—	—
Production	—	—	—	—	—	—	(19)	—	(19)	(7)	—	(7)	(20)	—	(20)
December 31, 2014	**—**	**—**	**—**	**—**	**—**	**—**	**110**	**230**	**340**	**50**	**18**	**68**	**118**	**233**	**351**
Total Canada															
December 31, 2013	2 577	1 612	4 189	1 887	854	2 741	70	281	351	57	41	97	4 544	2 754	7 298
Extensions & Improved Recovery[6]	—	—	—	—	—	—	1	10	11	10	2	12	2	10	13
Technical Revisions[7]	27	43	70	(7)	(117)	(124)	61	(59)	2	11	(15)	(3)	83	(136)	(53)
Discoveries[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	(3)	(2)	(5)	(19)	(10)	(29)	(6)	(4)	(10)
Economic Factors[9]	—	—	—	—	—	—	—	—	—	(2)	(1)	(2)	—	—	—
Production	(114)	—	(114)	(42)	—	(42)	(19)	—	(19)	(7)	—	(7)	(176)	—	(176)
December 31, 2014	**2 491**	**1 655**	**4 145**	**1 838**	**737**	**2 575**	**110**	**230**	**340**	**50**	**18**	**68**	**4 447**	**2 624**	**7 071**

Please see Notes (1) through (9) 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, 2014
(forecast prices and costs)

	SCO[4]			Bitumen			Light & Medium Oil			Natural Gas[5]			Total		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe	mmboe
North Sea															
December 31, 2013	—	—	—	—	—	—	107	36	144	5	3	8	108	37	145
Extensions & Improved Recovery[6]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[7]	—	—	—	—	—	—	3	(1)	2	1	(1)	—	3	(1)	2
Discoveries[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[9]	—	—	—	—	—	—	(2)	2	—	—	—	—	(2)	2	—
Production	—	—	—	—	—	—	(17)	—	(17)	(3)	—	(3)	(17)	—	(17)
December 31, 2014	**—**	**—**	**—**	**—**	**—**	**—**	**91**	**37**	**128**	**3**	**2**	**5**	**91**	**38**	**129**
Other International															
December 31, 2013	—	—	—	—	—	—	151	112	263	—	—	—	151	112	263
Extensions & Improved Recovery[6]	—	—	—	—	—	—	—	1	1	—	—	—	—	1	1
Technical Revisions[7]	—	—	—	—	—	—	(6)	(2)	(8)	—	—	—	(6)	(2)	(8)
Discoveries[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[9]	—	—	—	—	—	—	(1)	—	—	—	—	—	(1)	—	—
Production	—	—	—	—	—	—	(2)	—	(2)	—	—	—	(2)	—	(2)
December 31, 2014	**—**	**—**	**—**	**—**	**—**	**—**	**142**	**111**	**253**	**—**	**—**	**—**	**142**	**111**	**253**
Total															
December 31, 2013	2 577	1 612	4 189	1 887	854	2 741	329	429	758	62	44	105	4 804	2 902	7 706
Extensions & Improved Recovery[6]	—	—	—	—	—	—	1	11	12	10	2	12	2	12	14

Technical Revisions[7]	27	43	70	(7)	(117)	(124)	58	(63)	(4)	12	(15)	(3)	80	(140)	(59)
Discoveries[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	(3)	(2)	(5)	(19)	(10)	(29)	(6)	(4)	(10)
Economic Factors[9]	—	—	—	—	—	—	(3)	3	—	(2)	(1)	(2)	(3)	3	(1)
Production	(114)	—	(114)	(42)	—	(42)	(38)	—	(38)	(10)	—	(10)	(196)	—	(196)
December 31, 2014	**2 491**	**1 655**	**4 145**	**1 838**	**737**	**2 575**	**343**	**378**	**721**	**53**	**20**	**73**	**4 681**	**2 773**	**7 454**

Please see Notes (1) through (9) 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, 2014

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

(2) Reserves data tables may not add due to rounding.

(3) Other International includes quantities of crude oil in Libya, which are expected to be produced under EPSAs. Under these EPSAs, net proved and probable reserves have been determined using the economic interest method. See the Definitions for Reserves Data Tables and Best Estimate Contingent Resources.

(4) SCO reserves figures include the company's diesel sales volumes.

(5) Includes associated and non-associated gas (combined) as well as NGLs (1 mmbbls of proved and 1 mmbbls of proved plus probable NGLs reserves (gross) as at December 31, 2014).

(6) Extensions and Improved Recovery are additions to the reserves resulting from step-out drilling, infill drilling and implementation of improved recovery schemes. Negative volumes, if any, for probable reserves result from the initial recognition of proved reserves for reserves previously assigned as probable reserves.

(7) Technical Revisions include changes in previous estimates resulting from new technical data or revised interpretations.

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

(9) Economic Factors are changes due primarily to price forecasts, inflation rates or regulatory changes.

Definitions for Reserves Data Tables and Best Estimate Contingent Resources

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 (operated and non-operated) 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 (operated and non-operated) 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 reserves estimates presented are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation (COGE) Handbook. A summary of those definitions is set forth below.

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 analyses 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. Proved reserves estimates should target at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

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. That is, proved plus probable reserves estimates should target at least a 50% probability that the quantities actually recovered will equal or exceed the estimate.

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

Proved and probable reserves categories 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 estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

In the **economic interest method** used for PSCs, Suncor's share of profit revenue plus cost recovery revenue is divided by the associated oil or gas price forecast to determine Suncor's net volume entitlement, or **entitlement reserves**. The entitlement reserves are then adjusted to include reserves relating to income taxes payable by the national oil company on behalf of Suncor. 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.

Future Net Revenues Tables and Notes[1]

Net Present Value of Future Net Revenues Before Income Taxes
as at December 31, 2014
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value[2]
	0%	5%	10%	15%	20%	($/boe)
Proved Developed Producing						
Mining	34 387	20 097	12 770	8 698	6 267	8.03
In Situ	6 629	5 762	5 071	4 514	4 059	18.24
E&P Canada	2 180	1 995	1 833	1 694	1 576	37.93
Total Canada	43 195	27 853	19 674	14 907	11 902	10.27
North Sea	4 774	3 993	3 438	3 030	2 721	47.93
Other International	—	—	—	—	—	—
Total Proved Developed Producing	47 969	31 846	23 111	17 937	14 622	11.63
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	1 112	951	824	722	639	27.98
E&P Canada	32	24	19	15	13	12.68
Total Canada	1 144	975	843	737	651	27.25
North Sea	218	179	152	132	116	45.40
Other International	4 024	2 971	2 307	1 858	1 539	47.55
Total Proved Developed Non-Producing	5 387	4 126	3 301	2 727	2 307	39.88
Proved Undeveloped						
Mining	18 143	4 819	526	(1 148)	(1 895)	0.72
In Situ	33 432	16 677	8 973	5 085	2 960	7.80
E&P Canada	1 678	821	302	(22)	(227)	6.32
Total Canada	53 253	22 318	9 800	3 915	838	5.07
North Sea	779	676	593	525	469	36.52
Other International	50	33	21	12	6	29.91
Total Proved Undeveloped	54 082	23 027	10 414	4 452	1 313	5.34
Proved						
Mining	52 529	24 916	13 296	7 550	4 371	5.72
In Situ	41 173	23 390	14 867	10 321	7 658	10.20
E&P Canada	3 890	2 840	2 153	1 688	1 362	22.07
Total Canada	97 592	51 146	30 316	19 559	13 391	7.82
North Sea	5 771	4 849	4 183	3 687	3 306	45.81
Other International	4 075	3 004	2 327	1 870	1 545	47.30
Total Proved	107 438	58 999	36 827	25 116	18 242	9.16
Probable						
Mining	39 290	11 687	5 464	3 330	2 347	7.17
In Situ	70 813	19 482	7 344	3 637	2 200	6.22
E&P Canada	14 898	8 988	6 020	4 319	3 248	35.57
Total Canada	125 002	40 156	18 829	11 287	7 796	8.91
North Sea	3 102	2 249	1 712	1 355	1 104	45.24
Other International	4 872	2 723	1 670	1 106	777	40.03
Total Probable	132 976	45 128	22 212	13 747	9 677	10.13
Proved Plus Probable						

Mining	91 820	36 603	18 760	10 880	6 718	6.08
In Situ	111 987	42 871	22 212	13 958	9 858	8.42
E&P Canada	18 788	11 828	8 173	6 007	4 610	30.63
Total Canada	222 595	91 303	49 145	30 845	21 187	8.20
North Sea	8 873	7 098	5 895	5 042	4 410	45.64
Other International	8 947	5 727	3 998	2 976	2 322	43.96
Total Proved Plus Probable	240 415	104 127	59 038	38 863	27 919	9.50

Please see Notes (1) and (2) at the end of the Future Net Revenues tables for important information.

Net Present Value of Future Net Revenues After Income Taxes
as at December 31, 2014
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	26 389	15 303	9 669	6 562	4 716
In Situ	5 485	4 767	4 195	3 734	3 358
E&P Canada	1 847	1 691	1 551	1 432	1 331
Total Canada	33 722	21 761	15 416	11 728	9 405
North Sea	1 528	1 286	1 111	982	884
Other International	—	—	—	—	—
Total Proved Developed Producing	35 250	23 047	16 527	12 710	10 289
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	822	701	607	531	469
E&P Canada	32	24	19	15	13
Total Canada	854	725	625	546	482
North Sea	93	79	69	61	55
Other International	1 435	1 064	830	671	558
Total Proved Developed Non-Producing	2 383	1 869	1 524	1 278	1 095
Proved Undeveloped					
Mining	14 658	3 747	206	(1 182)	(1 806)
In Situ	24 557	11 903	6 176	3 327	1 790
E&P Canada	1 268	581	161	(101)	(269)
Total Canada	40 482	16 231	6 543	2 044	(285)
North Sea	292	260	233	210	191
Other International	17	11	6	3	—
Total Proved Undeveloped	40 791	16 501	6 782	2 256	(94)
Proved					
Mining	41 047	19 050	9 875	5 380	2 910
In Situ	30 864	17 371	10 978	7 592	5 617
E&P Canada	3 147	2 296	1 731	1 346	1 075
Total Canada	75 058	38 717	22 584	14 318	9 602
North Sea	1 913	1 625	1 413	1 253	1 130
Other International	1 453	1 075	836	674	558
Total Proved	78 424	41 417	24 833	16 245	11 290
Probable					
Mining	29 323	8 654	4 039	2 479	1 770
In Situ	52 422	14 257	5 369	2 671	1 623
E&P Canada	11 107	6 675	4 445	3 168	2 365
Total Canada	92 852	29 586	13 853	8 318	5 758
North Sea	1 198	898	701	567	472
Other International	1 705	953	585	387	272
Total Probable	95 756	31 437	15 139	9 272	6 501
Proved Plus Probable					
Mining	70 370	27 704	13 915	7 859	4 680

In Situ	83 286	31 629	16 347	10 263	7 239
E&P Canada	14 254	8 971	6 177	4 514	3 440
Total Canada	167 910	68 303	36 438	22 635	15 360
North Sea	3 111	2 523	2 114	1 821	1 602
Other International	3 158	2 028	1 420	1 061	830
Total Proved Plus Probable	174 179	72 854	39 972	25 517	17 791

Total Future Net Revenues
as at December 31, 2014
(forecast prices and costs)

(in $ millions, undiscounted)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Expenses	Future Net Revenues Before Deducting Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenues After Deducting Future Income Tax Expenses
Proved Developed Producing								
Mining	196 838	23 314	99 618	39 519	—	34 387	7 998	26 389
In Situ	22 104	1 352	11 323	2 650	149	6 629	1 143	5 485
E&P Canada	5 732	1 454	1 574	184	341	2 180	332	1 847
Total Canada	224 674	26 120	112 516	42 353	490	43 195	9 473	33 722
North Sea	7 418	—	2 275	223	146	4 774	3 246	1 528
Other International	—	—	—	—	—	—	—	—
Total Proved Developed Producing	232 091	26 120	114 791	42 576	636	47 969	12 719	35 250
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ	2 059	286	515	136	11	1 112	290	822
E&P Canada	72	6	29	2	2	32	—	32
Total Canada	2 131	292	544	138	12	1 144	290	854
North Sea	355	—	118	10	9	218	125	93
Other International	5 521	—	786	686	24	4 024	2 589	1 435
Total Proved Developed Non-Producing	8 007	292	1 448	835	46	5 387	3 004	2 383
Proved Undeveloped								
Mining	77 524	10 754	36 911	11 717	—	18 143	3 485	14 658
In Situ	133 986	20 880	50 483	28 475	715	33 432	8 876	24 557
E&P Canada	5 472	445	1 430	1 825	95	1 678	410	1 268
Total Canada	216 982	32 079	88 824	42 017	809	53 253	12 771	40 482
North Sea	1 615	—	531	272	34	779	487	292
Other International	76	—	4	22	—	50	33	17
Total Proved Undeveloped	218 673	32 079	89 358	42 311	844	54 082	13 291	40 791
Proved								
Mining	274 362	34 068	136 529	51 236	—	52 529	11 483	41 047
In Situ	158 148	22 518	62 321	31 262	874	41 173	10 309	30 864
E&P Canada	11 276	1 904	3 033	2 011	437	3 890	742	3 147
Total Canada	443 786	58 490	201 883	84 509	1 311	97 592	22 535	75 058
North Sea	9 387	—	2 923	504	189	5 771	3 858	1 913
Other International	5 597	—	790	708	24	4 075	2 622	1 453
Total Proved	458 771	58 490	205 597	85 721	1 525	107 438	29 015	78 424
Probable								
Mining	131 305	21 056	56 881	14 078	—	39 290	9 967	29 323
In Situ	236 306	45 018	80 497	39 204	774	70 813	18 391	52 422
E&P Canada	27 137	7 261	3 481	1 303	193	14 898	3 792	11 107
Total Canada	394 748	73 335	140 859	54 584	967	125 002	32 150	92 852
North Sea	4 504	—	1 278	94	29	3 102	1 904	1 198
Other International	5 423	—	338	209	4	4 872	3 167	1 705
Total Probable	404 674	73 335	142 476	54 887	1 000	132 976	37 221	95 756

Proved Plus Probable

Mining	405 667	55 124	193 410	65 314	—	91 820	21 450	70 370
In Situ	394 455	67 536	142 818	70 465	1 648	111 987	28 701	83 286
E&P Canada	38 413	9 166	6 515	3 313	630	18 788	4 534	14 254
Total Canada	838 534	131 826	342 743	139 093	2 278	222 595	54 685	167 910
North Sea	13 891	—	4 202	598	218	8 873	5 761	3 111
Other International	11 020	—	1 128	917	28	8 947	5 789	3 158
Total Proved Plus Probable	863 445	131 826	348 072	140 608	2 525	240 415	66 235	174 179

Future Net Revenues by Production Group [1]
as at December 31, 2014
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	$/boe[2]
Proved Developed Producing		
Unconventional – Mining	12 770	8.03
Unconventional – In Situ	5 071	18.24
Total Unconventional[3]	17 841	9.55
Light & Medium Oil[4]	5 229	45.44
Natural Gas[5]	41	8.24
Total Proved Developed Producing	23 111	11.63
Proved		
Unconventional – Mining	13 296	5.72
Unconventional – In Situ	14 867	10.20
Total Unconventional[3]	28 163	7.45
Light & Medium Oil[4]	8 604	37.14
Natural Gas[5]	60	9.27
Total Proved	36 827	9.16
Proved Plus Probable		
Unconventional – Mining	18 760	6.08
Unconventional – In Situ	22 212	8.42
Total Unconventional[3]	40 972	7.16
Light & Medium Oil[4]	17 988	37.62
Natural Gas[5]	78	8.94
Total Proved Plus Probable	59 038	9.50

(1) Figures may not add due to rounding.

(2) Unit values are net present values of future net revenues before deducting estimated cash income taxes payable, discounted at 10%, divided by net reserves.

(3) Total Unconventional includes SCO and bitumen.

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

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

Notes to Future Net Revenues Tables

In Situ Future Net Revenues

Future net revenues for In Situ properties reflect the flexibility of Suncor's operations, which allows production from these properties to be either upgraded to SCO or sold as non-upgraded bitumen. The proportion of upgraded production is based on estimated available upgrading capacity and can vary depending on unplanned maintenance, fluctuations in production from mining and extraction operations, or changes in the company's overall Oil Sands development strategy, including with respect to planned upgrading capacity.

Future net revenues disclosed above include the estimated uplift to the future sales price and the associated upgrader operating and sustaining capital costs of upgrading approximately 40-50% of Firebag bitumen production to SCO from 2015 to 2034 and 100% thereafter. These factors translate to a $1.4 billion increase in the net present value of future net revenues (total proved plus probable reserves, before tax, discounted at 10%) from In Situ production relative to the scenario where none of the bitumen is upgraded.

Revenues and the natural gas fuel expense associated with excess power generated from cogeneration facilities at Firebag are included in future net revenues.

Prices Realized

For prices realized by Suncor during 2014, 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, 2015, 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.

Forecast prices included a US$/Cdn$ exchange rate of 0.85 in 2015 and 0.875 thereafter, a Cdn$/€ exchange rate of 1.45 and a Cdn$/£ exchange rate of 1.80. Forecast costs included a 2% inflation factor, except for costs for Mining, which included 4% inflation for 2016, 3% inflation for 2017 and 2% thereafter.

Prices Impacting Reserves Tables[1]

Forecast	Brent North Sea[2]	WTI Cushing Oklahoma	WCS Hardisty Alberta[3]	Light Sweet Edmonton Alberta[4]	Pentanes Plus Edmonton Alberta[5]	AECO Gas[6]	B.C. Gas Westcoast Station 2[7]	National Balancing Point North Sea[8]
Year	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu	Cdn$/mmbtu
2015	67.50	62.50	54.35	64.71	69.24	3.31	3.16	8.82
2016	82.50	75.00	67.20	80.00	85.60	3.77	3.62	9.43
2017	87.50	80.00	72.00	85.71	91.71	4.02	3.87	10.00
2018	90.00	85.00	76.80	91.43	97.83	4.27	4.12	10.29
2019	95.00	90.00	81.60	97.14	103.94	4.53	4.38	10.86
2020	100.00	95.00	86.40	102.86	110.06	4.78	4.63	11.43
2021	101.35	98.54	89.19	106.18	113.62	5.03	4.88	11.58
2022	103.38	100.51	90.98	108.31	115.89	5.28	5.13	11.81
2023	105.45	102.52	92.79	110.47	118.20	5.53	5.38	12.05
2024	107.56	104.57	94.65	112.67	120.56	5.71	5.56	12.29
2025+	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year

(1) Each price from the GLJ forecast was adjusted for quality differentials and transportation costs applicable to the specific product and evaluation area.

(2) Price used when determining offshore light and medium oil reserves for E&P Canada, North Sea reserves and Other International reserves.

(3) Price used when determining bitumen reserves presented as In Situ and Mining reserves as well as for determining bitumen pricing for royalty calculation purposes.

(4) Price used when determining SCO reserves presented as In Situ and Mining reserves, and onshore light and medium oil reserves for E&P Canada.

(5) Price used when determining the cost of diluent associated with bitumen reserves presented as In Situ and Mining reserves, as well as for determining bitumen pricing for royalty calculation purposes. A bitumen/diluent ratio of approximately two barrels of bitumen for one barrel of diluent was used. Price also used when determining NGLs reserves.

(6) Price used when determining natural gas input costs for the production of SCO and bitumen reserves.

(7) Price used when determining natural gas reserves for E&P Canada areas.

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

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

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 E&P Canada) or at a business area or legal entity level (for North Sea) based on tax pools associated with that business area or legal entity. Income taxes for Other International assets are determined by their respective EPSAs. Suncor's actual corporate legal entity structure for income taxes and income tax planning has 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 2014 audited Consolidated Financial Statements and the MD&A should be consulted for information on income taxes at the corporate entity level.

Future Development Costs[1]
as at December 31, 2014
(forecast prices and costs)

($ millions)	2015	2016	2017	2018	2019	Remainder	Total	Discounted At 10%
Proved								
Mining	3 602	4 016	3 004	1 667	1 857	37 091	51 236	23 602
In Situ	1 285	1 071	1 101	1 273	1 110	25 422	31 262	11 771
E&P Canada	797	471	167	91	87	398	2 011	1 614
Total Canada	5 684	5 558	4 272	3 031	3 053	62 911	84 509	36 986
North Sea	155	70	95	11	13	160	504	355
Other International	40	74	31	32	33	498	708	335
Total Proved	5 879	5 702	4 398	3 074	3 099	63 570	85 721	37 677
Proved Plus Probable								
Mining	3 590	4 019	3 003	1 714	1 925	51 064	65 314	25 338
In Situ	1 354	1 372	811	1 114	1 124	64 690	70 465	13 806
E&P Canada	960	682	468	279	201	723	3 313	2 537
Total Canada	5 904	6 073	4 282	3 107	3 250	116 477	139 092	41 681
North Sea	181	88	95	11	13	211	598	404
Other International	51	75	36	35	33	688	917	386
Total Proved Plus Probable	6 136	6 236	4 412	3 153	3 296	117 376	140 608	42 471

(1) Figures may not add due to rounding.

Development costs include costs associated with both developed and undeveloped reserves. Significant development activities and costs for 2015 are expected to include:

- For Mining, development of tailings management facilities and water management assets for Oil Sands Base, development of tailings management facilities, improvements to utilities facilities, and mine train replacements at Syncrude. Remaining development costs for Oil Sands Base and Syncrude relate to capital investments that maintain the production capacity of existing facilities, including, but not limited to, major maintenance, truck and shovel replacement, the replenishment of catalysts in hydrotreating units at the upgraders and improvements to utilities, roads and other facilities. Development activities for Syncrude also relate to the development of the Aurora South pit in order to sustain upgrader throughput when the Mildred Lake mining area depletes. Development activities for Fort Hills continue to focus on detailed engineering, procurement, and field construction activities.
- For both Firebag and MacKay River operations within In Situ, the drilling of new well pairs and the design and construction of new well pads that are expected to maintain existing production levels in future years.
- For E&P Canada, construction activities at Hebron and Hibernia extensions, as well as development drilling at Hibernia and White Rose.
- For North Sea, continuation of Golden Eagle development drilling.
- For Other International, maintenance to facilities in Libya.

Management currently believes that internally generated cash flows, existing and future credit facilities, and access to debt capital markets 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 could 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 consolidated abandonment and reclamation costs. This review considers the nature of Suncor's forecasted production and development plans, consistent with that assumed in our long-range planning, where determinable, for liabilities associated with its upstream operations as at December 31, 2014. Where no legal liability or constructive obligation for reclamation exists, potential costs have been excluded from the company's abandonment and reclamation cost estimates. Estimates are based on the anticipated method and extent of restoration, consistent with legal requirements, technological advances and the possible future use of the site.

As at December 31, 2014, Suncor estimated its undiscounted, uninflated abandonment and reclamation liability for surface leases, wells, facilities and pipelines pertaining to its upstream assets, to be approximately $8.7 billion (discounted at 10%, approximately $2.4 billion). This cost estimate does not include the company's estimated abandonment and reclamation costs for its Refining and Marketing assets ($0.2 billion, undiscounted and uninflated). Suncor estimates that it will incur $1.1 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2015 – $0.4 billion, 2016 – $0.4 billion, 2017 – $0.3 billion), over 80% of which is associated with Oil Sands mining operations. The $8.7 billion abandonment and reclamation costs are associated with Suncor's current disturbances and wells drilled as at December 31, 2014. This estimate does not include costs for future planned disturbances or future wells that have yet to be drilled.

Approximately $2.5 billion (undiscounted) has been deducted as abandonment costs in estimating the future net revenues from proved plus probable reserves. This $2.5 billion represents the abandonment obligation for approximately 2,100 net production wells and approximately 1,800 net service and other wells, including a forecasted number of future wells for undeveloped reserves related to in situ and conventional activities that are not included in Suncor's $8.7 billion total.

Abandonment and reclamation costs included in Suncor's $8.7 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 for which no reserves have been assigned.

Additional Information Relating to Reserves Data

Gross Proved and Probable Undeveloped Reserves

The tables below outline the gross proved and probable undeveloped reserves and represent undeveloped reserves additions resulting from acquisitions, discoveries, infill drilling, improved recovery and/or extensions pertaining to the year in which the events first occurred.

Gross Proved Undeveloped Reserves [1]
(forecast prices and costs)

	Prior		2012		2013		**2014**	
	First Attributed	Total at December 31 2011	First Attributed	Total at December 31 2012	First Attributed	Total at December 31 2013	**First Attributed**	**Total at December 31 2014**
SCO (mmbbls)								
Mining	—	—	—	—	—	—	—	—
In Situ	502	502	46	493	75	564	—	**532**
Total SCO	502	502	46	493	75	564	—	**532**
Bitumen (mmbbls)								
Mining	—	—	—	—	845	845	—	**845**
In Situ	661	661	64	785	74	875	—	**830**
Total Bitumen	661	661	64	785	918	1 720	—	**1 674**
Light & Medium Oil (mmbbls)								
E&P Canada[2]	27	27	4	32	2	27	**38**	**52**
North Sea	43	43	—	32	—	25	—	**16**
Other International[3]	6	6	4	4	—	5	—	**2**
Total Light & Medium Oil	76	76	7	67	2	57	**38**	**70**
Natural Gas (bcfe)[4]								
E&P Canada[2]	79	79	—	80	4	5	—	—
North Sea	3	3	—	2	—	1	—	**1**
Other International[3]	—	—	—	—	—	—	—	—
Total Natural Gas	82	82	—	82	4	6	—	**1**
Total (mmboe)	1 253	1 253	117	1 359	996	2 342	**38**	**2 277**

Gross Probable Undeveloped Reserves [1]
(forecast prices and costs)

	Prior		2012		2013		2014	
	First Attributed	Total at December 31 2011	First Attributed	Total at December 31 2012	First Attributed	Total at December 31 2013	**First Attributed**	**Total at December 31 2014**
SCO (mmbbls)								
Mining	263	263	—	260	—	265	—	**265**
In Situ	1 212	1 212	—	1 043	—	1 074	—	**1 112**
Total SCO	1 475	1 475	—	1 303	—	1 339	—	**1 378**
Bitumen (mmbbls)								
Mining	—	—	—	—	397	397	—	**408**
In Situ	669	669	—	594	—	369	—	**268**
Total Bitumen	669	669	—	594	397	766	—	**677**
Light & Medium Oil (mmbbls)								
E&P Canada[2]	219	219	5	222	22	236	**10**	**189**
North Sea	17	17	2	33	—	23	—	**13**
Other International[3]	14	14	8	8	—	9	**1**	**3**
Total Light & Medium Oil	251	251	14	262	22	267	**11**	**205**
Natural Gas (bcfe)[4]								
E&P Canada[2]	92	92	1	54	17	21	—	**3**
North Sea	2	2	—	4	—	2	—	**1**
Other International[3]	416	416	—	—	—	—	—	—
Total Natural Gas	510	510	1	57	17	23	—	**4**
Total (mmboe)	2 480	2 480	14	2 170	422	2 376	**11**	**2 260**

(1) Figures above may not add due to rounding.

(2) E&P Canada includes properties previously held by Suncor and subsequently disposed of in 2011, 2013 and 2014.

(3) Other International includes properties held by Suncor in Syria which were classified as contingent resources in 2012.

(4) Includes immaterial amounts of NGLs (no more than 20% of each of the values shown).

Undeveloped In Situ reserves, which constitute approximately 60% of Suncor's gross proved undeveloped reserves and 61% of Suncor's gross probable undeveloped reserves, will take several years to develop. Undeveloped In Situ reserves have been assigned to reserves areas which are not classified as developed producing. Where supported by core hole wells, proved undeveloped reserves have been attributed to regions within 1.2 km from currently drilled or near-term planned production wells where AER approval is pending and, in the case of Firebag, also within 2.4 km from producing wells. 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. The timing associated with developing undeveloped reserves is a function of the forecasts of the declining production from existing In Situ wells. Suncor has delineated In Situ reserves to a high degree of certainty through seismic data and core hole drilling, consistent with COGE Handbook guidelines. In most cases, proved reserves have been drilled to a density of 16 wells per section, which is 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 constitute approximately 37% of Suncor's gross proved undeveloped reserves and 30% of Suncor's gross probable undeveloped reserves, and relate to the Fort Hills mining area and Syncrude Aurora South mining area, which have regulatory approvals substantially in place and are well-delineated by core hole drilling. First oil for the Fort Hills mining area is expected by the fourth quarter of 2017. The co-owners of Syncrude do not expect that the Aurora South mining area will come on-stream before 2024, when production from the Mildred Lake mining area is expected to be complete.

Undeveloped conventional (light and medium oil, natural gas and NGLs) reserves constitute approximately 3% of Suncor's gross proved undeveloped reserves and approximately 9% of Suncor's gross probable undeveloped reserves. Undeveloped conventional reserves primarily relate to the company's offshore assets at E&P Canada, mainly associated with Hebron which is currently under development (first oil expected in 2017), and underdrilled or undrilled fault blocks related to extension areas in Hibernia, White Rose and Terra Nova. In developing these reserves, Suncor considers existing facility 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. 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.

Properties with no Attributed Reserves

The following table is a summary of properties to which no reserves are attributed as at December 31, 2014. 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	6 715 533	3 831 801
Libya	2 950 978	1 339 489
U.S. – Alaska	798 040	265 987
Norway	545 065	172 571
Syria[(1)]	345 194	345 194
U.K.	117 201	41 515
Australia (overriding royalty interest only)	113 027	—
Total	11 585 038	5 996 557

(1) Does not include hectares for lands associated with reserves that were reclassified to contingent resources in 2012 as a result of the suspension of operations.

Suncor's undeveloped petroleum assets include 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. Certain Mining and In Situ properties may be in a relatively mature phase of evaluation, where a significant amount of development has occurred; however, reserves cannot be attributed due to one or more contingencies, such as project sanction. 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 process to review the economic viability of its properties, some properties are selected for further development activities, while others are temporarily deferred, sold, swapped or relinquished back to the mineral rights' owner.

In 2015, Suncor's rights to 33,217 net hectares in Canada and 37,325 net hectares in Norway are scheduled to expire. Substantial portions of expiring lands may have their tenure continued beyond 2015 through the conduct of work programs and/or the payment of prescribed fees to the rights' owner. No land tenure expiries are scheduled to occur for either Mining or In Situ properties for 2015.

Oil and Gas Properties and Wells

The following table is a summary of oil and gas wells associated with the company's operations as at December 31, 2014.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing[1][2]		Producing		Non-Producing[1][2]	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta – In Situ[3]	249.0	249.0	126.0	126.0	—	—	—	—
British Columbia	—	—	—	—	36.0	31.0	9.0	8.4
Newfoundland	68.0	17.6	1.0	0.3	—	—	—	—
North Sea	33.0	9.8	4.0	1.2	—	—	—	—
Other International[4]	—	—	419.0	211.1	—	—	6.0	6.0
Total	350.0	276.4	550.0	338.6	36.0	31.0	15.0	14.4

(1) Non-producing wells include, but are not limited to, wells where there is no near-term plan for abandonment, wells where drilling has finished but the well has not been completed, wells requiring maintenance or workover where the resumption of production is not known, and wells that have been shut in and the date of resumption of production is not known with reasonable certainty.

(2) Non-producing wells do not necessarily lead to classification of non-producing reserves, which are described subsequently in this description.

(3) SAGD well pairs are counted as one well. Wells where steam injection has commenced are classified as producing.

(4) Other International includes wells associated with the company's suspended operations in Syria. There are no reserves associated with wells in Syria, only contingent resources. The number assumes that no wells have been damaged since Suncor exited the country in December 2011.

There are no producing 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 three years, which require further capital for completion and tie-in to facilities to bring the wells on-stream. Because this capital is small relative to the cost to drill, complete and tie-in a well pair, the associated reserves are considered developed.

Proved plus probable developed non-producing reserves for North Sea are primarily associated with recently drilled development wells to be brought on production in 2015.

For Other International, non-producing reserves are associated with wells in Libya that were suspended due to political unrest in the country, which resulted in the closure of export terminal operations at eastern Libyan seaports. Production in Libya was temporarily resumed in the last half of 2014 but was again shut in by year end and, as such, all associated reserves were classified as non-producing.

Costs Incurred

The table below summarizes the company's costs incurred related to its oil and gas activities for the year ended December 31, 2014.

($ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Other Costs[1]	Total
Canada – Mining and In Situ	161	—	—	3 427	50	3 638
Canada – E&P Canada	62	—	1	1 191	—	1 254
Total Canada	223	—	1	4 618	50	4 892
North Sea	176	—	—	342	—	518
Other International	58	—	—	19	—	77
Total	457	—	1	4 979	50	5 487

(1) Other Costs includes infrastructure for pipelines and storage tanks.

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, 2014.

	Exploratory Wells[1]		Development Wells	
Total number of wells completed	Gross	Net	Gross	Net
Canada – Oil Sands				
Oil	1.0	1.0	33.0	33.0
Service[2]	4.0	3.8	55.0	55.0
Stratigraphic Test[3]	358.0	215.2	603.0	295.9
Total	363.0	220.0	691.0	383.9
Canada – E&P Canada				
Oil	—	—	2.0	0.6
Dry Hole	—	—	1.0	0.3
Natural Gas	—	—	2.0	2.0
Service[2]	—	—	3.0	0.8
Stratigraphic Test[3]	1.0	0.3	—	—
Total	1.0	0.3	8.0	3.7
North Sea				
Oil	—	—	4.0	1.1
Service[2]	—	—	1.0	0.3
Dry Hole	2.0	0.6	2.0	0.6
Stratigraphic Test[3]	3.0	0.9	—	—
Total	5.0	1.5	7.0	2.0
Other International				
Dry Hole	2.0	1.0	—	—
Total	2.0	1.0	—	—

(1) Exploratory wells for Oil Sands includes activity related to technology pilot projects.

(2) Service wells for Oil Sands includes the injection well in a SAGD well pair, in addition to observation and disposal wells. Service wells for E&P Canada include water injection wells.

(3) Stratigraphic test wells for Oil Sands includes core hole drilling wells. Stratigraphic test wells for offshore properties include appraisal wells.

Significant exploration and development activities in 2014 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, the drilling of new well pairs and infill wells at Firebag and MacKay River that are expected to assist in maintaining production levels in future years, core hole drilling programs at MacKay River, Meadow Creek, Firebag and Lewis to further delineate resources, and activity to start up pilot technology projects.
- For E&P Canada, development drilling for Terra Nova, Hibernia, HSEU, and the White Rose Extensions.
- For North Sea, exploration and development drilling for Buzzard and GEAD, which are in the U.K. sector of the North Sea.
- For Other International, exploration wells in Libya.

Production History[1]

The table below outlines the company's historical production information, by product type. Average price realized is net of transportation costs, but before royalties.

2014	Q1	Q2	Q3	Q4	Year Ended
Canada – Oil Sands[2]					
Total production (mbbls/d)	424.4	403.1	441.1	419.3	422.1
Total In Situ bitumen production (mbbls/d)	187.1	199.8	199.1	210.9	199.0
($/bbl)					
Average price realized	96.49	99.33	91.87	73.20	90.27
Royalties	(5.04)	(6.88)	(10.62)	(2.79)	(6.38)
Total cash operating costs[3]	(36.61)	(35.89)	(31.99)	(35.32)	(34.90)
In Situ cash operating costs[3]	(19.90)	(17.80)	(15.25)	(14.05)	(16.64)
Canada – Light & Medium Oil[4]					
Total production (mbbls/d)	59.9	55.5	46.8	58.1	55.0
($/bbl)					
Average price realized	119.62	120.44	110.41	78.51	106.24
Royalties	(34.41)	(34.78)	(31.71)	(14.52)	(25.97)
Production costs	(10.14)	(12.28)	(13.74)	(14.66)	(13.11)
Netback[6]	75.07	73.38	64.96	49.33	67.16
North Sea – Light & Medium Oil[5]					
Total production (mboe/d)	56.5	54.3	24.2	56.2	47.7
($/boe)					
Average price realized	111.55	113.63	106.49	82.27	104.12
Royalties	—	—	—	—	—
Production costs	(5.77)	(5.73)	(14.74)	(4.47)	(6.42)
Netback[6]	105.78	107.90	91.75	77.80	97.70

(1) Production and liftings in Libya have been intermittent and are not considered material to Suncor and therefore are not included.

(2) Suncor measures cash operating cost on a production volumes basis for its Oil Sands operations. For this reason, a netback calculation for SCO and bitumen is not presented in this table.

Amounts presented include results from the company's share of Syncrude.

(3) Non-GAAP financial measures. See the Advisories section of this AIF.

(4) Volumes exclude natural gas and NGLs production from E&P Canada onshore properties, which is not considered material to Suncor.

(5) Volumes include field production for associated gas and NGLs.

(6) Netbacks have been calculated by subtracting royalties and production costs from revenue.

The following table provides the production volumes on a working interest basis, before royalties for each of Suncor's significant fields for the year ended December 31, 2014.

	SCO	Bitumen	Light & Medium Oil
	mbbls/d	mbbls/d	mbbls/d
Mining – Suncor	213.0	—	—
Mining – Syncrude	31.0	—	—
Firebag	75.6	75.4	—
MacKay River	0.3	26.4	—
Buzzard	—	—	47.1
GEAD	—	—	0.6
Hibernia	—	—	23.1
White Rose	—	—	14.6
Terra Nova	—	—	17.3
Total	319.9	101.8	102.7

Production Estimates

The table below outlines the production estimates for 2015 that are included in the estimates of gross proved reserves and gross probable reserves as at December 31, 2014. Production estimates for 2015 for proved plus probable reserves, evaluated as at December 31, 2014, from Suncor's mining operations (excluding Syncrude) are 226.2 mbbls/d of SCO, approximately 39% of total estimated production for 2015, and from Firebag are 159.2 mbbls/d of SCO and bitumen, approximately 28% of total estimated production for 2015.

	SCO (mbbls/d)		Bitumen (mbbls/d)		Light & Medium Oil (mbbls/d)		Natural Gas (mmcfe/d)[1]		Total (mmboe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
Proved	316.2	308.4	113.3	109.6	51.9	39.3	19.3	15.9	484.6	460.0
Probable	19.1	18.9	3.2	3.1	7.1	6.2	1.8	1.6	29.7	28.5
Proved Plus Probable	335.3	327.3	116.6	112.7	59.0	45.5	21.2	17.5	514.3	488.5
North Sea										
Proved	—	—	—	—	48.0	48.0	5.0	5.0	48.8	48.8
Probable	—	—	—	—	2.4	2.4	0.8	0.8	2.6	2.6
Proved Plus Probable	—	—	—	—	50.5	50.5	5.8	5.8	51.4	51.4
Other International										
Proved	—	—	—	—	8.1	1.9	—	—	8.1	1.9
Probable	—	—	—	—	—	—	—	—	—	—
Proved Plus Probable	—	—	—	—	8.1	1.9	—	—	8.1	1.9
Total										
Proved	316.2	308.4	113.3	109.6	108.0	89.3	24.4	20.9	541.5	510.8
Probable	19.1	18.9	3.2	3.1	9.5	8.6	2.6	2.4	32.3	31.0
Proved Plus Probable	335.3	327.3	116.6	112.7	117.5	97.9	27.0	23.3	573.8	541.8

(1) Includes 0.4 mmbbls/d proved and 0.5 mmbbls/d proved plus probable NGLs production (gross) in 2015 production estimate.

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, 2014. These commitments run through 2020 and beyond, and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area ($ millions)	2015	Total
Canada	3	103
North Sea	133	155
Other International	10	416

Forward Contracts

Suncor may use financial derivatives to manage its exposure to fluctuations in commodity prices; however, Suncor did not consider any financial derivative transactions to be material in 2014. A description of Suncor's use of such instruments is provided in the 2014 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2014.

Tax Horizon

In 2014, Suncor was subject to cash tax in the majority of the local jurisdictions in which it generates earnings, including earnings related to its Canadian, North Sea and Other International production.

Contingent Resources

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. The contingent resources estimates provided herein are best estimates of the quantities that are potentially recoverable. 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. Contingent resources can be further classified into the following subclasses:

Development Pending is where resolution of the final conditions for development is being actively pursued (high chance of development).

Development On Hold is where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

Development Unclarified is when the evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties.

Development Not Viable is where no further data acquisition or evaluation is currently planned and, hence, there is a low chance of development.

The discussion below also makes reference to evaluation scenario status and recovery technology status which are described in the COGE Handbook [(1)].

Evaluation scenario status, in relation to particular resources, is defined as follows:

Conceptual Study – the initial stage of the development of a project scenario, with limited detail and typically based on limited information. Major parameters will be mostly assumed. While the results may be sufficient for initial delineation of the resources and for identifying the need for additional technical data, they will be insufficient for making economic decisions regarding development.

Pre-Development Study – is an intermediate step in the development of a project evaluation scenario. The amount of information that is available for the reservoir of interest is greater than for a conceptual study. In particular, the petroleum initially in place has been reasonably well defined and the remaining uncertainty lies largely in the recovery factor and the economic viability. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision or for seeking outside major financing.

Development Study – is the most detailed step in the development of a project evaluation scenario. It is based on a detailed geological and engineering study and economic analysis of information on the specific project, and provides

(1) These descriptions are abbreviated. For more complete descriptions, please see the description in the COGE Handbook.

sufficient information for the creation of a development plan, from which a development decision can be made.

Recovery technology status, in relation to particular resources, is defined as follows:

Established Technology – methods that have been proven to be successful in commercial applications.

Technology Under Development – a recovery process or process improvement project that has been determined to be technically viable via field test and is being field tested further to determine its economic viability in the subject reservoir.

Experimental Technology – is a technology that is being field tested to determine the technical viability of applying a recovery process or process improvement project to unrecoverable discovered petroleum initially in place in a subject reservoir. Experimental technology differs from established technology and technology under development in that it is being tested for technical, not commercial, viability and is usually at a smaller scale.

GLJ conducted independent assessments of best estimate contingent resources volumes for all of Suncor's Mining and In Situ properties. Sproule Unconventional Limited conducted an independent assessment of Suncor's best estimate contingent resources contained in the Kobes/Montney shale formation of northeast B.C. (approximately 33% of Suncor's E&P contingent resources). Best estimate contingent resources for remaining conventional properties were prepared by Suncor's internal qualified reserves evaluators without independent audit or review. All contingent resources estimates were conducted in accordance with the COGE Handbook. The effective date of Suncor's best estimate of contingent resources is as of December 31, 2014, except in the case of Syria, which is as at December 31, 2011.

In 2011, the company's assets in Syria were impacted by political unrest and international sanctions. As a result, volumes previously reported as reserves based on an evaluation conducted by Sproule with an effective date of December 31, 2011 were reclassified to contingent resources in 2012 and have remained classified as contingent resources since that time. As political unrest in Syria has persisted throughout 2014, the company has not been able to update any information used by Sproule since the 2011 evaluation. The contingent resources estimate for Syria assumes that there has been no production subsequent to Sproule's 2011 evaluation and that infrastructure, including wells and pipelines, existing at December 31, 2011, exist at December 31, 2014. Therefore, these contingent resources are subject to uncertainty arising from any new information or change in circumstances, such as production, changes in asset performance or condition, or development activities, about which Suncor and Sproule are unaware.

There is no certainty that all or any portion of the contingent resources will be commercially viable to produce, or as to the timing of any such development. The economic viability of the contingent resources is dependent upon pricing and economic conditions. Estimates of contingent resources have not been adjusted for risk based on the chance of development. Significant factors that may change contingent resources estimates include further delineation drilling, future technology improvements, and additional processing capacity.

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

- The need for higher density core hole drilling to improve the certainty of Mining and In Situ resources;
- The need for further facility design and the associated uncertainty in development costs and timelines;
- The preparation of firm development plans and regulatory applications (including associated reservoir studies and delineation drilling);
- The need for regulatory approvals;
- In the case of Libya and Syria, the need for a more stable political and security situation; and
- The need for Board, management or partner approval, as applicable, to proceed with development.

The additional facility design work, development plans, reservoir studies and delineation drilling are often completed in the course of preparing the company's application for regulatory approvals. Once there is a high level of certainty of receiving all regulatory, corporate and co-owner approvals, as applicable, and all other contingencies are removed, the resources may then be reclassified as reserves.

Also, the company has assumed that some Mining and 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.

Suncor's best estimate of gross contingent resources is set out in the table below.

Best Estimate Contingent Resources[1]	SCO	Bitumen	Light & Medium Oil	Natural Gas[4]	Total
	mmbbls	mmbbls	mmbbls	bcfe	mmboe
Mining	4 426	818	—	—	5 244
In Situ	7 124	7 087	—	—	14 210
E&P Canada[2]	—	—	270	19 992	3 602
Total Canada	11 550	7 905	270	19 992	23 056
North America Onshore – U.S.[2]	—	—	—	449	75
North Sea[2]	—	—	69	37	75
Other International[2][3]	—	—	402	1 147	593
As at December 31, 2014	11 550	7 905	740	21 624	23 798
As at December 31, 2013	10 680	8 122	705	22 428	23 245

(1) Figures may not add due to rounding.

(2) For a description of which properties are included, see page 52 under the heading "Exploration and Production".

(3) Includes contingent resources for Syria of approximately 206 mmboe. A portion of these contingent resources were previously classified as reserves as at December 31, 2011, based on a reserves evaluation prepared by Sproule with an effective date of December 31, 2011. These reserves have been reclassified as contingent resources as a result of Suncor's suspension of operations in Syria.

(4) Includes 208 mmbbls (1,248 bcfe) of NGLs, 157 mmbbls of which are in the Kobes/Montney shale formation of northeast B.C.

Contingent resources increased to 23,798 mmboe as at December 31, 2014 from 23,245 mmboe as at December 31, 2013, due primarily to an increase in In Situ contingent resources resulting from additional drilling that added bitumen contingent resources, primarily at the company's Lewis property. Sub-classifications are as follows: Development Pending (0.5%); Development On Hold (2.5%); Development Unclarified (88.4%); and Development Not Viable (8.6%).

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 consider 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. Except where otherwise noted, all contingent resources are based on Established Technology.

Oil Sands

Mining Contingent Resources

Mining contingent resources comprise approximately 22% of Suncor's total contingent resources, with 73% of these contingent resources related to 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%.

Approximately 98% of Mining contingent resources are classified as Development Unclarified due to ongoing activities, such as core hole drilling and development planning, which are being undertaken to further assess future development plans for these contingent resources. Evaluation scenario statuses are primarily Conceptual Study (approximately 83%) and Pre-Development Study (approximately 16%) stage.

Economic Contingencies

The economic status of Suncor's Mining contingent resources is currently undetermined and is dependent on the company's long-term resource development plan and its forecast for economic conditions. Prior to reserves being assigned, these contingent resources require the completion of further resource studies and delineation drilling, and the preparation of development plans and facility designs.

Non-Technical Contingencies

The reclassification of all Mining contingent resources to reserves is contingent upon an assessment that development will be sanctioned and commence within a reasonable time frame.

Although regulatory permits for the Joslyn North mining project have been obtained, in May 2014, Suncor, together with the other co-owners, agreed to scale back certain development activities in order to focus on engineering studies to further optimize the project development plan. As a result, the volumes from the Joslyn North mining project have been classified as contingent resources.

Suncor's remaining Mining contingent resources are primarily contingent upon regulatory permits which must be obtained before project sanction decisions by Suncor's Board of Directors and/or co-owners, as applicable, are considered.

In Situ Contingent Resources

In Situ contingent resources comprise approximately 60% of Suncor's total contingent resources, with approximately 83% of these contingent resources related to 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%. All In Situ contingent resources are associated with clastic or sandstone formations in the Athabasca oil sands area and approximately 83% of the contingent resources are in, or adjacent to, existing Firebag or MacKay River operations.

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

Suncor also owns mineral rights in 288 sections of the Grosmont carbonate formation, all at a 100% working interest. Core hole drilling completed on these sections has identified bitumen in the Grosmont, Upper Ireton and Nisku carbonate formations. In addition, Suncor has acquired data from numerous third-party pilots currently in operation in Grosmont carbonates. However, Suncor has not recognized any contingent resources in carbonate formations, as the viability of potential recovery processes in Suncor's carbonate interests has not yet been established.

All In Situ contingent resources are classified as Development Unclarified as a result of ongoing activities, such as seismic studies, core hole drilling, well testing and facility design, to further future development plans. Currently, these resources are at the Conceptual Study (approximately 7%) or Pre-Development (approximately 93%) stage and have primarily been based on the application of established SAGD technology. A small portion (less than 4%) having an upper zone of lower bitumen saturation is being field tested for commerciality and, hence, may be considered to have a recovery technology status of Technology Under Development. No contingent resources have been assigned to those new technologies described in the Narrative Description of Suncor's Businesses section as those technologies are currently considered experimental.

Economic Contingencies

The economic status of In Situ contingent resources is currently undetermined. However, technical net pay cutoffs are consistent with, and based upon, the same economic conditions as those used in the determination of proved plus probable reserves for Firebag and MacKay River, or are analogous to existing in situ SAGD operations successfully developed by other entities in the oil sands industry.

Contingent resources have been assigned to certain sections associated with Firebag and MacKay River. These volumes have not been classified as reserves in part because drilling density is inadequate for reliable mapping of effective pay intervals. However, the company has two-dimensional and three-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 Firebag and MacKay River operations full.

Contingent resources for other In Situ properties (Chard, Kirby, Lewis and Meadow Creek) were assigned to sections with core holes, or lands within two legal subdivisions of a delineation well and net continuous bitumen pay greater than approximately ten to 15 metres, depending on the horizon and property. Within the Athabasca oil sands, economic production has been demonstrated at these thicknesses. Prior to reserves being assigned, these contingent resources require the completion of further reservoir studies and delineation drilling, and the preparation of development plans and facility designs. The company expects that an assessment of the economic viability of these contingent resources will be undertaken as the company's long-term plans for its upgrading facilities 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. Certain contingent resources associated with Firebag and MacKay River have regulatory approvals in place, but final investment decisions are subject to detailed assessments 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/or co-owners, as applicable.

Exploration and Production

Exploration and Production's contingent resources comprise approximately 18% of Suncor's total contingent resources. These contingent resources primarily include:

- For E&P Canada, extensions of existing producing oilfields, natural gas resources associated with existing producing oilfields, and other hydrocarbon accumulations that are not currently producing, including those offshore Newfoundland and Labrador. It also includes resources in the Kobes/Montney formation in northeast B.C., the Arctic Islands, and the Mackenzie Delta and Corridor.

- For North America Onshore – U.S., resources in the Alaska Foothills.

- For North Sea, discoveries offshore Norway and the U.K. and extensions of existing producing oilfields.

- For Other International, volumes associated with the company's suspended operations in Syria and, in Libya, undeveloped portions within existing producing fields and other discovered hydrocarbon accumulations that are not currently producing. As a result of the suspension of Suncor's operations in Syria, volumes classified as reserves as at December 31, 2011 were reclassified as contingent resources and remain classified as contingent resources as at December 31, 2014.

E&P's contingent resources are anticipated to be recoverable using established technologies including horizontal drilling, artificial lift and improved recovery methods such as waterflood.

For E&P Canada, most (approximately 73%) of light and medium oil contingent resources are associated with Hebron, Hibernia, Terra Nova and White Rose. These, and natural gas contingent resources in Kobes/Montney, are classified as Development Unclarified due to ongoing drilling activity to further assess the resources for development. These projects are in a Pre-Development Study stage. The remaining E&P Canada contingent resources are in the Conceptual Study stage and are currently classified as Development Not Viable. These are primarily related to geographically remote areas (Mackenzie Delta and Corridor, Arctic Islands, Labrador) which lack regional infrastructure and for which there are currently no plans for further data acquisition or evaluation.

North America Onshore – U.S. properties are in the Conceptual Study stage and are currently classified as Development Not Viable. These are related to geographically remote areas in Alaska which lack regional infrastructure and for which there are currently no plans for further data acquisition or evaluation.

North Sea contingent resources are primarily in the Conceptual Study stage and are primarily classified as Development Unclarified due to ongoing drilling activity to further assess the resources for development.

Other International contingent resources are classified as Development On Hold due to ongoing political unrest in Libya and Syria which has precluded further assessment for an indefinite period of time.

Economic Contingencies

Except as noted below, the economic status of these 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 under current conditions.

For E&P Canada, contingent oil resources for Hebron, Terra Nova and White Rose and a portion of Hibernia (in total comprising approximately 4% of E&P Canada's total contingent resources) have been determined to be economic. The company anticipates that it will assess the economic viability of remaining Hibernia contingent oil resources within the next five years. Most (approximately 97%) of the contingent resources in the Kobes/Montney shale gas formation were determined to be economic (comprising approximately 39% of E&P Canada's total contingent resources). Remaining E&P Canada contingent resources are primarily in geographically remote areas and are currently sub-economic due to lack of processing and transportation infrastructure in these areas. These remote 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. Suncor working interests associated with these resources range from 8% to 100%. Timing for completion of economic evaluation of contingent resources in remote areas is not anticipated to occur within the next five years.

North America Onshore – U.S. contingent resources are in geographically remote areas and are currently sub-economic due to lack of processing and transportation infrastructure in these areas. These remote 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.

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.

Other International contingent resources in Libya associated with developed fields are economic, while the economic viability of resources associated with fields that are not developed 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 reserves is contingent upon the receipt of appropriate regulatory approvals, and an assessment that development will be sanctioned by Suncor's Board and co-owners, as applicable, and commence within a reasonable time frame. Contingent resources for some E&P Canada onshore properties in geographically remote areas are also contingent upon the development of a suitable regulatory framework.

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). These regulations are 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, Alberta, British Columbia and Newfoundland and Labrador, 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. All current legislation is a matter of public record, and the company is unable to predict what additional legislation or amendments may be enacted. All governments have the ability to change legislation. Suncor may engage in the discussion on proposed changes to ensure Suncor's interests are recognized. The following discussion outlines some of the principal aspects of legislation, regulations and agreements governing Suncor's operations.

Pricing, Marketing and Exporting Crude Oil

The producers of oil are entitled to negotiate sales and purchase agreements directly with oil purchasers. Most agreements are linked to global oil prices. 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). 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 NEB is currently drafting amending regulations to update the current regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-Term Prosperity Act*, which received Royal Assent on June 29, 2012 (the Prosperity Act). In the transitory period, the NEB has issued, and is currently following an Interim Memorandum of Guidance concerning *Oil and Gas Export Applications and Gas Import Applications under Part VI of the National Energy Board Act* .

Under the North American Free Trade Agreement (NAFTA), Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36-month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements.

NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. 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.

Royalties, Incentives and Income Taxes

Canada

The royalty regime is a significant factor in the profitability of SCO, bitumen, crude oil, NGLs and natural gas production. Royalties 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 or by agreement with government in certain circumstances, which are subject to change as a result of numerous factors, including political considerations, and are generally calculated as a percentage of revenues received from the value of the gross production. The royalty rate 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.

For a discussion of the royalties in Alberta and Newfoundland and Labrador, refer to the Narrative Description of Suncor's Businesses section of this AIF.

The Canadian federal corporate income tax rate levied on taxable income was 15% for active business income, including resource income. The average provincial income tax rate for Suncor in 2014 was 10.66%.

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.

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

Amounts presented in the 2014 audited Consolidated Financial Statements as royalties for production from our Libya operations are determined pursuant to EPSAs. 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 respective EPSAs. All government interests in these operations, except for income taxes, are presented as royalties.

Under our EPSAs in Libya, NOC remits taxes on Suncor's behalf. Until tax clearance certificates from tax authorities are received, Suncor records both an income tax payable to the taxation authority and an offsetting receivable from the NOC.

Land Tenure

In Canada, crude oil 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 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, grants tenure in the form of exploration, significant discovery and production licences.

In many other international jurisdictions, crude oil and natural gas are most commonly owned by national governments that grant rights in the form of exploration licences and permits, production licences, PSCs and other similar forms of tenure. In all cases, Suncor's right to explore, develop and produce crude oil 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. Among other things, they provide for restrictions and prohibitions on the spill, release or emission of various substances produced in association with production that apply to Suncor and other companies in the energy industry. The regulatory regimes require Suncor 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 mine, well and facility sites to the satisfaction of regulatory 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, Suncor expects 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 Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring, and the Lower Athabasca Regional Plan (LARP) that implements a land-use regime in the Athabasca oil sands. These statutes, regulations and frameworks relate to such issues as tailings management, water use, air emissions 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 enacted in the future. 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. 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, continuing land reclamation activities, installing new emissions abatement equipment, investing in research and development and

working to advance other environmental technologies such as solvent based extraction techniques.

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 have policies based on (i) caps on the intensity of GHG emissions including absolute GHG emissions limits, (ii) a cap-and-trade system, (iii) a tax, (iv) a hybrid of a tax and a cap-and-trade system, or (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 with government and indirectly through industry associations.

International Climate Change Agreements and Treaties

The Government of Canada has committed, pursuant to an agreement at the United Nations Framework Convention on Climate Change Conference of the Parties (UNFCCC COP) held in Copenhagen, Denmark, in 2009 (Copenhagen Accord), to reducing its GHG emissions by 17% below 2005 levels by 2020, in line with the reduction commitment made by the U.S. The Copenhagen Accord does not contain any binding commitments for reducing CO_2 emissions, nor does it include any discussion of compliance mechanisms. The 2014 UNFCCC COP, held in Lima, Peru, continued to focus on creating a process and plan for all UN members to reach an agreement on 2020 commitments by the 2015 UNFCCC COP to be held in Paris, France. Countries are asked to pledge their intended nationally determined contributions by June 30, 2015.

Canadian Federal GHG Regulations

The Government of Canada continues to pursue harmonization with the U.S. (where appropriate) and has already implemented regulations on two of Canada's largest sources of emissions, being transportation and thermal electricity generated from coal (which includes petroleum coke). In line with the U.S., Canada has adopted a renewable fuels standard, mandating that 5% of gasoline supply come from renewable sources such as ethanol and that 2% of diesel supply come from bio-diesel. The Canadian federal government continues to address emissions of specific sectors of the economy and has been engaged in negotiations with the Canadian oil and gas industry on proposed regulations for the sector while ensuring the industry remains globally competitive. It is expected that provincial governments will enter into equivalency agreements for their own regulations with regard to a future federal regulation.

Canadian Provincial GHG Regulations

At the 2014 Canadian Premiers' conference, the leaders of all 10 provinces and three territories released an updated Canadian Energy Strategy (CES) that included renewed vision and principles for enhanced actions on clean energy and climate change in Canada. CES work, expected to wrap up in summer 2015, includes an enhanced focus on subnational co-operative climate change mitigation action, and highlights carbon pricing and carbon capture and storage.

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 is committed to fully complying with existing regulations and will continue to constructively 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* (SGER) enacted under the *Climate Change and Emissions Management Act (Alberta)*, facilities in Alberta emitting more than 100,000 tonnes of CO_2 equivalent (CO_{2e}) per year became subject to intensity limits (GHG emissions per unit of production) and are required to reduce their intensity limits by 12% from an established baseline. Four facilities operated by Suncor in Alberta (Oil Sands Base plant, MacKay River operations, Firebag operations and the Edmonton refinery) are subject to, and continue to comply with, this legislation. For the 2013 compliance year, the total cost to comply with the SGER was approximately $9 million. Compliance under the SGER was achieved through reduced emissions per unit of production, and purchase and retirement of internally generated emission performance credits (EPCs) and externally purchased offset credits. The cost of compliance was slightly lower than the $15/tonne CO_{2e} under Alberta's Climate and Emission Management Fund (Alberta Technology Fund) due to the realized cost for purchasing offsets and emission performance credits. For the 2014 compliance year, the total compliance costs to Suncor are estimated to be between $13 million and $18 million, based on a cost of $15/tonne of CO_{2e}. The SGER was originally statutorily mandated to be renewed and is subject to possible revision in September 2014. That time frame has been extended to June 30, 2015, and it is currently unknown what changes will be implemented under any revised SGER.

Several Canadian provinces (including British Columbia, Ontario and Quebec) are members of the Western Climate Initiative (WCI), a multi-jurisdictional partnership, whose members also include individual U.S. states. WCI was created in 2007 to address climate change with the initiative to reduce greenhouse gas emissions at the regional level to 15% below 2005 levels by 2020.

The Province of British Columbia enacted a carbon tax in 2008, which is capped at $30/tonne of CO_{2e} through 2018. This carbon tax is revenue neutral, in that revenues are recycled back to taxpayers via tax reductions, and is applied on consumption. Suncor's natural gas production and gathering facilities, and refined product distribution terminals in B.C. do not exceed the 25,000 tonne reporting threshold under these regulations. The purchaser or user of fuels pays the B.C. carbon tax which is collected by Suncor and forwarded on to the government.

As of January 1, 2014, Quebec's cap-and-trade system became formally linked to the WCI. Allowances and offsets are fungible across the WCI. The California Cap-and-Trade Program and Quebec Cap-and-Trade System held their first joint carbon allowance auction on November 25, 2014. Suncor's Montreal refinery is subject to Quebec's cap-and-trade system for GHG emissions because it produces more than 25,000 tonnes of CO_{2e} per year. Emitters must verify their emissions during specified compliance periods (the first period having commenced 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. For the 2014 compliance year, the total cost to comply under the Quebec cap-and-trade system was approximately $1.5 million. Effective January 1, 2015, the second compliance period under WCI commenced to cover emissions from transportation fuels and combustibles. As a wholesale transportation fuels distributor, Suncor is subject to the second compliance period based on the anticipated annual GHG emissions attributed to the use of fuel distributed to consumers and fuel consumed by Suncor. This second compliance period will end on December 31, 2017. The third compliance period, whose procedures will be identical to the second, will begin on January 1, 2018 and end on December 31, 2020. For the 2015 compliance year, the projected total compliance costs are estimated to be $72 million, consisting of $70 million to cover emissions attributed to the distribution of transportation fuels and $2 million attributed to stationary emissions at Suncor's Montreal refinery. It is expected that the majority of the compliance costs covering the emissions from transportation fuels will be passed through to the consumer, resulting in a net compliance cost anticipated to be less than $5 million.

In mid-2014, the premiers of Ontario and Quebec agreed to strengthen bilateral co-operation on a range of issues, including climate change and carbon pricing. Ontario continues to consult with stakeholders on the development of a GHG reduction program for Ontario's industrial sector, intended to achieve equivalency with federal government regulation.

U.S. GHG Regulations

The U.S. supports 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. It is expected that the U.S. will work to advance the 2013 Climate Action Plan to reduce GHG emissions. In the absence of other federal legislation on GHG emissions, the current administration of the United States is endorsing the U.S. Environmental Protection Agency (EPA) to regulate GHG emissions under the *Clean Air Act*, starting with the thermal power sector. The implications on the oil and gas industry being regulated under the EPA and the timing of such regulations remain unknown. In the meantime, the EPA has implemented a mandatory GHG reporting rule for all large facilities (emitting greater than 25,000 tonnes of CO_{2e} per year), which includes Suncor's refinery in Commerce City, Colorado.

The EPA has also mandated Renewable Fuel Standards 2, which encourages ethanol blending of 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 passed AB32, which provides for a Low Carbon Fuel Standard (LCFS). After years of litigation around the constitutionality of AB32, the U.S. Supreme Court on June 30, 2014 validated the state's efforts to address climate change. AB32 was the first program in the U.S. to take a comprehensive, long-term approach to addressing climate change, and does so in a way that aims to improve the environment and natural resources while maintaining a robust economy in California. AB32 requires California to reduce its GHG emissions to 1990 levels by 2020.

International Regulations

Phase III (2008-2012) of the European Union Emissions Trading Scheme (EU ETS), which is applicable until 2020, impacts Suncor's non-operated offshore assets 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 will include a transition from gratis allocation to auctioning allowances.

As part of its ongoing business planning, Suncor assesses potential costs associated with CO_2 emissions in its evaluation of future projects, based on the company's 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, the company expects 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 its strategy, using a price range of $15 to $60/tonne of CO_{2e} as a base case, applied against a range of regulatory policy options and price sensitivities.

Land Use

In 2012, the Government of Alberta approved the LARP, which covers land-use restrictions in the Lower Athabasca region of Alberta, which includes leases in 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 to ensure the continued regional 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, including the use of environmental cumulative effects management on a regional scale, and may require Suncor to have greater participation in the evaluation of environmental issues. The frameworks include the following:

- **Air quality.** 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. Regulatory actions will occur when triggers or limits are reached or exceeded.

- **Surface water quality.** 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. Regulatory actions will occur when triggers or limits are reached or exceeded.

- **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 or exceeded.

Additional environmental management frameworks for surface water quantity and tailings management (see below) are expected to be finalized in early 2015.

Reclamation and Tailings

In February 2009, the Energy Resources Conservation Board (ERCB) of Alberta, now the Alberta Energy Regulator or AER, 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'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} by providing space for the drying of tailings and ensuring adequate storage capacity for tailings from the Millennium and North Steepbank areas. Syncrude's tailings management plan was approved by the ERCB in 2010 and incorporates a multi-pronged approach that includes freshwater capping, composite tailings technology (accelerates water from tailings with additives), and the separation of water and tailings through the use of centrifuges.

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 remediation and surface reclamation work at their mine sites, and for the 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, which Suncor has provided in the form of letters of credit, and which would provide the funds necessary to safely secure the site. Suncor is in compliance with the MFSP. Additional security may be 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. The MFSP has been designed by the Government of Alberta to include a periodic review of the program to ensure it is functioning properly and provide early warning of any potential risks.

Alberta Environment and Sustainable Resource Development is currently finalizing the Tailings

Management Framework (TMF). The TMF builds on, but does not replace, existing provincial legislation and policy on tailings management (such as Directive 74) and reclamation. The TMF is expected to establish fluid tailings volume triggers and limits to manage fluid tailings accumulation within oil sands mine tailings ponds. In addition, it is anticipated that the TMF will result in technological innovations in tailings management and reduce the overall volumes of fluid fine tailings associated with oil sands mining and extraction.

Joint Canada – Alberta Implementation Plan for Oil Sands Monitoring

In 2012, Canada and Alberta adopted the Joint Canada – Alberta Implementation Plan for Oil Sands Monitoring (Monitoring Plan). The intent of the Monitoring Plan is to provide scientifically rigorous, comprehensive, integrated and transparent environmental monitoring, including an improved understanding of the cumulative environmental impact of oil sands development. The total costs to the industry of enhanced monitoring under the Monitoring Plan have been estimated at approximately $50 million per year. The costs to Suncor under the Monitoring Plan are estimated at approximately $10 million per year.

Alberta has since created the Alberta Environmental Monitoring, Evaluation and Reporting Agency (AEMERA). AEMERA will steward the Monitoring Plan on behalf of the province and in conjunction with the Government of Canada.

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. Suncor is a founding member of COSIA and is committed to collaborative action to accelerate improvements in environmental performance, including tailings, water, land and GHG emissions. COSIA works with other collaborative networks to share knowledge and expertise about new technologies and innovation related to environmental performance.

RISK FACTORS

Suncor is committed to a proactive program of enterprise risk management intended to enable decision-making through consistent identification of risks inherent to its assets, activities and operations. Some of these risks are common to operations in the oil and gas industry as a whole, while some are unique to 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.

Volatility of Commodity Prices

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 prices for all of these commodities can be influenced by global and regional supply and demand factors, which are factors that are beyond our control and can result in a high degree of price volatility.

Crude oil prices are also affected by, among other things, global economic health and global economic growth (particularly in emerging markets), pipeline constraints, regional and international supply and demand imbalances, political developments, compliance or non-compliance with quotas agreed upon by OPEC members, decisions by OPEC not to impose quotas on its 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.

Refined petroleum products prices and refining margins are also affected by, among other things, crude oil prices, the availability of crude oil and other feedstock, 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.

In addition, oil and natural gas producers in North America, and particularly in Canada, may receive discounted prices for their production relative to certain international prices, due to constraints on the ability to transport and sell such products to international markets. A failure to resolve such constraints may result in continued discounted or reduced commodity prices realized by oil and natural gas producers such as Suncor.

Through the latter half of 2014 and into 2015, world oil prices have declined significantly. A prolonged period of low and/or volatile prices could affect the value of our upstream and downstream assets and the level of spending on growth projects, and could result in the curtailment of production from some properties and/or the impairment of that property's 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, and may also lead to the impairment of assets, or the cancellation or deferral of Suncor's growth projects.

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, or interpretation thereof, could impact Suncor's existing and planned projects as well as impose costs on compliance resulting in increased capital expenditures and operating expenses. Changes in government policy or regulation can also have an indirect impact on Suncor, including opposition to new North American pipeline systems, such as the Keystone XL or the Northern Gateway proposals. The result of such changes can also lead to additional compliance costs and staffing and resource levels, and also increase exposure to other risks to Suncor's business, including environmental or safety non-compliance and permit approvals.

Income Taxes

Pursuant to the previously disclosed 2013 proposal letter from the Canada Revenue Agency (CRA), in 2014, the company received a Notice of Reassessment (NOR) from the CRA regarding the income tax treatment of realized losses in 2007 on the settlement of certain derivative contracts. The total amount of the NOR including tax, penalty and interest was approximately $920 million. Also during the year:

- The company received NORs related to the derivative contracts from Quebec and Ontario for approximately $42 million and $100 million, respectively. The Alberta NOR (approximately $124 million) was received in the first quarter of 2015.

- The company provided security to the CRA and the Provinces of Quebec and Ontario for approximately $610 million.
- The company filed Notices of Objection with the CRA and the Provinces of Quebec and Ontario.
- The company filed a Notice of Appeal with the Tax Court of Canada.
- If the company is unsuccessful in defending its tax filing position, it could be subject to an earnings and cash impact of up to $1.2 billion.

Royalties

Royalties can be impacted by changes in crude oil and natural gas pricing, production volumes, 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. The final determination of these events may have a material impact on royalties payable to provincial and local governments and on the company's royalties expense.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Operational Outages and Major Environmental or Safety Incidents

Each of Suncor's primary operating businesses – Oil Sands, E&P, and Refining and Marketing – demands significant levels of investment in the design, operation and maintenance of facilities, and, therefore, carries the additional economic risk associated with operating reliably or enduring a protracted operational outage.

The company's 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, fines, civil suits or criminal charges against the company.

Generally, Suncor's operations are subject to operational hazards and risks such as fires, explosions, blow-outs, power outages, severe winter climate conditions and other extreme weather conditions, rail car incident or derailment 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 Suncor's 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. The company is also subject to operational risks such as sabotage, terrorism, trespass, theft and malicious software or network attacks.

In addition to the foregoing factors that affect Suncor's business generally, each business unit is susceptible to additional risks due to the nature of its business, as follows:

- Oil Sands operations are susceptible to loss of production, slowdowns, shutdowns or restrictions on our ability to produce higher value products, due to the failure of any one or more of its interdependent component systems;
- 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. Refer also to Significant Risk Factors and Uncertainties Affecting Reserves Data;
- E&P offshore operations occur in areas subject to hurricanes and other extreme weather conditions, such as winter storms, pack ice, icebergs and fog. The occurrence of any of these events could result in production shut-ins, the suspension of drilling operations, damage to or destruction of the equipment involved and injury or death of rig personnel. Suncor's offshore operations could also be affected by the actions of Suncor's 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 the company's 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; and
- Suncor's Refining and Marketing operations are also 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.

Although the company maintains 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 Suncor operations.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Regulatory Approval and Compliance

Before proceeding with most major projects, including significant changes to existing operations, Suncor must obtain various federal, provincial or state permits and regulatory approvals. Suncor must also obtain licences to operate certain assets. These processes can involve, among other things, stakeholder consultation, environmental impact assessments and public hearings, and may be subject to conditions, including security deposit obligations and other commitments. Suncor can also be indirectly impacted by a third party's inability to obtain regulatory approval for a shared infrastructure project. Compliance can also be affected by the loss of skilled staff, inadequate internal processes and compliance auditing.

As part of ongoing operations, the company is also required to comply with a large number of EH&S regulations under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations. Failure to comply with these regulations may result in the imposition of fines and penalties, production constraints, reputational damage, operating and growth permit applications, censure, liability for cleanup costs and damages, and the loss of important licences and permits.

Failure to obtain, comply with or maintain regulatory permits and approvals, or failure to obtain them on a timely basis or on satisfactory terms, could result in delays, abandonment or restructuring of projects and increased costs, all of which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Project Execution

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.

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, in accordance with design, and at the agreed cost; and
- Commissioning and startup – a failure of the facility to meet agreed performance targets, including operating costs, efficiency, yield and maintenance costs.

Project execution can also be impacted by:

- Failure to comply with Suncor's project implementation model;
- The availability, scheduling and cost of materials, equipment and qualified personnel;
- The complexities associated with integrating and managing contractor staff and suppliers in a confined construction area;
- Our ability to obtain the necessary environmental and other regulatory approvals;
- The impact of general economic, business and market conditions and our ability to finance growth, including major growth projects in progress, if commodity prices were to decline and stay at low levels for an extended period;
- The impact of weather conditions;
- Risks relating to restarting projects placed in safe mode, including increased capital costs;
- The effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment;
- Risk associated with offshore fabrication and logistics;
- Risks relating to scheduling, resources and costs, including the availability and cost of materials, equipment and qualified personnel;
- The accuracy of project cost estimates, as actual costs for major projects can vary from estimates, and these differences can be material;
- Our ability to complete strategic transactions; and
- The commissioning and integration of new facilities within our existing asset base could cause delays in achieving guidance, targets and objectives.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Fossil Fuel Industry Reputation

Suncor works within an environment characterized by concerns over climate change, with environmental limits seen as a legitimate constraint on economic growth and increased activism and public opposition to fossil fuels. In addition, the social value proposition of resource deployment is being challenged.

Future laws and regulations may impose significant liabilities on a failure to comply with their requirements. Concerns over climate change and fossil fuel extraction could lead governments to enact additional or more stringent laws and regulations applicable to Suncor.

Changes in environmental regulation could impact 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.

Climate Change

Suncor continues to actively monitor the international and domestic efforts to address climate change. While it currently appears that GHG regulations and targets will continue to become more stringent, and while Suncor will continue efforts to reduce the intensity of its GHG emissions, the absolute GHG emissions of our company are expected to rise as we pursue a prudent and planned growth strategy. Increases in GHG emissions may impact the profitability of our projects, as Suncor may be subject to incremental levies and taxes.

Land Reclamation

There are risks associated specifically with the company's ability to reclaim 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 the volumes of fluid fine tailings. The inability of TRO $_{TM}$ or any other methods of technology and/or the increase in time to reclaim tailings ponds could increase Suncor's decommissioning and restoration cost estimates.

Alberta's Land-Use Framework

The implementation of, and compliance with, the terms of the LARP may adversely impact our current properties and projects in northern Alberta due to, among other things, environmental limits and thresholds. Due to the cumulative nature of the plan, the impact of the LARP on Suncor's operations may be outside of the control of the company, as Suncor's operations could be impacted as a result of restrictions imposed due to the cumulative impact of development, by the operators in the area and not solely in relation to Suncor's direct impact.

Alberta Environment Water Licences

We currently rely on fresh water, which is obtained under licences from Alberta Environment, to provide domestic and utility water at our Oil Sands operations. Water licences, like all regulatory approvals, contain conditions to be met in order to maintain compliance with the licence. There can be no assurance that the licences to withdraw water will not be rescinded or that additional conditions will not be added to these licences. There can be no assurance that the company will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of the company's projects may rely on securing licences for additional water withdrawal, and there can be no assurance that these licences will be granted or that they will be granted on terms favourable to Suncor.

There is a risk that future laws or changes to existing laws or regulations could cause capital expenditures and operating expenses to increase or the demand for our products to decrease. There is also a risk that Suncor could face litigation initiated by third parties relating to climate change.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Change Capacity

In order to achieve Suncor's business objectives, the company must operate efficiently, reliably and safely, and, at the same time, deliver growth and sustaining projects safely, on budget and on schedule. The ability to achieve these two sets of objectives is critically important to Suncor to deliver value to shareholders and stakeholders. These objectives also demand a large number of improvement initiatives that compete for resources, and may negatively impact the company should there be inadequate consideration of the cumulative impacts of prior and parallel initiatives on people, processes and systems. There is also a risk that these objectives may exceed Suncor's capacity to adopt and implement change. The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Cost Management

Suncor is exposed to the risk of escalating operating costs in both its Oil Sands business and other businesses. Suncor's inability to successfully manage costs may constrain its ability to execute high-quality projects that deliver lower operating costs. Factors contributing to these risks include, but are not limited to, the skills and resource shortage and the long-term success of existing and new in situ technologies. The risk of escalating operating costs in both its Oil Sands business and other businesses could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Market Access

Suncor anticipates higher production of bitumen in future years, due mainly to production growth from debottlenecking at MacKay River and growth projects at

Fort Hills. The markets for bitumen blends or heavy crude are more limited than those for light crude, making them more susceptible to supply and demand changes and imbalances (whether as a result of pipeline constraints or otherwise). Heavy crude oil generally 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, and this price differential can be amplified due to supply and demand imbalances.

There is a risk that constrained market access for oil sands production due to insufficient pipeline takeaway capacity, growing inland production and refinery outages, creates risk of widening differentials that could impact the profitability of product sales which could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Information Security

The efficient operation of Suncor's 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. There is a risk that any significant interruption or the failure of these systems to perform as anticipated for any reason could disrupt our business and could result in decreased performance, production, or increased costs, and could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Financial Risks

Energy Trading and Risk Management Activities and the Exposure to Counterparties

The nature of Suncor's energy trading and risk management activities, which may make use of derivative financial instruments to hedge its commodity price and other market risks, creates exposure to significant financial risks, which include, but are not limited to, the following:

- Unfavourable movements in commodity prices, interest rates or foreign exchange could result in a financial or opportunity loss to the company;
- A lack of counterparties, due to market conditions or other circumstances, could leave us unable to liquidate or offset a position, or unable to do so at or near the previous market price;
- We may not receive funds or instruments from our counterparty at the expected time or at all;
- The counterparty could fail to perform an obligation owed to us;
- Loss as a result of human error or deficiency in our systems or controls; and
- Loss as a result of contracts being unenforceable or transactions being inadequately documented.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Exchange Rate Fluctuations

Our Consolidated Financial Statements are presented in Canadian dollars. The majority of Suncor's revenues from the sale of oil and natural gas are based on prices that are determined by, or referenced to, U.S. dollar benchmark prices, while the majority of Suncor's expenditures are realized in Canadian dollars. The company also holds substantial amounts of U.S. dollar debt. Suncor's results, therefore, can be affected significantly by the exchange rates between the Canadian dollar and the U.S. dollar. The company also undertakes operations administered through international subsidiaries and, so, to a lesser extent, Suncor's results can be affected by the exchange rates between the Canadian dollar and the euro, and the Canadian dollar and the British pound. These exchange rates may vary substantially and may give rise to favourable or unfavourable foreign currency exposure.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Interest Rate Risk

We are exposed to fluctuations in short-term Canadian and U.S. interest rates as Suncor maintains a portion of its debt capacity in revolving and floating rate bank facilities and commercial paper, and invests surplus cash in short-term debt instruments. We are also exposed to interest rate risk when debt instruments are maturing and require refinancing, or when new debt capital needs to be raised. Unfavourable changes in interest rates could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Issuance of Debt and Debt Covenants

Suncor expects that future capital expenditures will be financed out of cash generated from operations and borrowings. This ability is dependent on, among other factors, commodity prices, the overall state of the capital markets and investor appetite for investments in the energy industry generally and our securities in particular. To the extent that external sources of capital become limited or unavailable or available on unfavourable terms, our ability

to make capital investments and maintain existing properties may be constrained.

If we finance capital expenditures in whole or in part with debt, that may increase our debt levels above industry standards for oil and gas companies of similar size. Depending on future development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms, including higher interest rates and fees. Neither the articles of Suncor (the Articles) nor its bylaws limit the amount of indebtedness that we may incur; however, we are subject to covenants in our existing bank facilities and seek to avoid an unfavourable cost of debt. The level of our indebtedness, from time-to-time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise and could negatively affect our credit ratings.

We are required to comply with financial and operating covenants under existing credit facilities and debt securities. We routinely review the covenants based on actual and forecast results and have the ability to make changes to our development plans, capital structure and/or dividend policy to comply with covenants under the credit facilities. If Suncor does not comply with the covenants under its credit facilities and debt securities, there is a risk that repayment could be accelerated and/or the company's access to capital could be restricted or only be available on unfavourable terms.

Rating agencies regularly evaluate the company and our subsidiaries. Their ratings of our long-term and short-term debt are based on a number of factors, including our financial strength, as well as factors not entirely within our control, including conditions affecting the oil and gas industry generally, and the wider state of the economy. Credit ratings may be important to customers or counterparties when we compete in certain markets and when we seek to engage in certain transactions, including transactions involving over-the-counter derivatives. There is a risk that one or more of our credit ratings could be downgraded, which could potentially limit our access to private and public credit markets and increase cost of borrowing.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Third-Party Service Providers

Suncor is reliant on the operational integrity of a large number of third-party service providers, including input and output commodity transport (pipelines, rail, trucking, marine) and utilities associated with various Suncor facilities, including electricity. A disruption in service by one of these third parties can also have a dramatic impact on Suncor's operations. Pipeline constraints that affect takeaway capacity or supply of inputs, such as hydrogen and power for example, could 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 produce and 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. There is a risk that third-party outages could impact Suncor's production or price realizations, which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Foreign Operations

The company has operations in a number of countries with different political, economic and social systems. As a result, the company's operations and related assets are subject to a number of risks and other uncertainties arising from foreign government sovereignty over the company's international operations, which may include, among other things:

- Currency restrictions and restrictions on repatriation of funds;
- Loss of revenue, property and equipment as a result of expropriation, nationalization, war, insurrection and geopolitical and other political risks;
- Increases in taxes and government royalties;
- Compliance with existing and emerging anti-corruption laws, including the *Foreign Corrupt Practices Act* (United States), the *Corruption of Foreign Officials Act* (Canada) and the United Kingdom *Bribery Act*;
- Renegotiation of contracts with government entities and quasi-government agencies, including risks regarding negotiations in Libya with the NOC related to the periods in which Suncor was in force majeure under its EPSAs;
- 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, there is a risk the company could also be exposed to potential claims for alleged breaches of international law.

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. Suncor 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 Suncor will be successful in protecting itself against these risks and the related financial consequences.

Despite Suncor's training and policies around bribery and other forms of corruption, there is a risk that Suncor, or some of its employees or contractors, could be charged with bribery or corruption. Any of these violations could result in onerous penalties. Even allegations of such behaviour could impair Suncor's ability to work with governments or non-government organizations and could result in the formal exclusion of Suncor from a country or area, sanctions, fines, project cancellations or delays, the inability to raise or borrow capital, reputational impacts and increased investor concern.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Joint Arrangement Risk

Suncor has entered into joint arrangements and other contractual arrangements with third parties with respect to certain of its projects where other entities operate assets in which Suncor has ownership or other interests. The success and timing of Suncor's activities on assets and projects operated by others, or developed jointly with others, depend upon a number of factors that are outside of Suncor's control, including the timing and amount of capital expenditures, the timing and amount of operational and maintenance expenditures, the operator's expertise, financial resources and risk management practices, the approval of other participants, and the selection of technology.

These co-owners may have objectives and interests that do not coincide with and may conflict with Suncor's interests. Major capital decisions affecting joint arrangements may require agreement among the co-owners, while certain operational decisions may be made solely at the discretion of the operator of the applicable assets. While joint venture counterparties may generally seek consensus with respect to major decisions concerning the direction and operation of the assets and the development of projects, no assurance can be provided that the future demands or expectations of the parties relating to such assets and projects will be met satisfactorily or in a timely manner. Failure to satisfactorily meet demands or expectations by all of the parties may affect our participation in the operation of such assets or in the development of such projects, our ability to obtain or maintain necessary licences or approvals, or the timing for undertaking various activities. In addition, disputes may arise pertaining to the timing and/or capital commitments with respect to projects that are being jointly developed, which could materially adversely affect the development of such projects and Suncor's business and operations.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Technology Risk

There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations, including that the results of the application of new technologies may differ from simulated or test environments. The success of projects incorporating new technologies cannot be assured. Advantages accrue to companies that can develop and adopt emerging technologies in advance of competitors. The inability to develop, implement and monitor new technologies may impact the company's ability to develop its new or existing operations in a competitive or profitable manner, which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Skills, Resource Shortage and Reliance on Key Personnel

The successful operation of Suncor's businesses and our ability to expand operations will depend upon the availability of, and competition for, skilled labour and materials supply. There is a risk that we may have difficulty sourcing the required labour for current and future operations. The risk could manifest itself primarily through an inability to recruit new staff without a dilution of talent, to train, develop and retain high-quality and experienced staff without unacceptably high attrition, and to satisfy an employee's work/life balance and desire for competitive compensation. The labour market in Alberta has been historically tight, and while the current economic situation has partially moderated this effect, it remains a risk to be managed. The increasing age of our existing workforce adds further pressure. Materials may also be in short supply

due to smaller labour forces in many manufacturing operations. Our ability to operate safely and effectively and complete all our projects on time and on budget has the potential to be significantly impacted by these risks and this impact could be material.

Our success also depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the company. The contributions of the existing management team to the immediate and near-term operations of the company are likely to continue to be of central importance for the foreseeable future.

Labour Relations

Hourly employees at our Oil Sands facilities, all of our refineries, certain of our lubricants operations, certain of our terminalling and distribution operations, and our Terra Nova FPSO are represented by labour unions or employee associations. Any work interruptions involving our employees, contract trades utilized in our projects or operations, or any jointly owned facilities operated by another entity presents a significant risk to the company and could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Competition

The global petroleum industry is highly competitive in many aspects, including the exploration for and the development of new sources of supply, the acquisition of crude oil and natural gas interests, and the refining, distribution and marketing of refined petroleum products. We compete in virtually every aspect of our business with other energy companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

For Suncor's Oil Sands segment, a number of other companies have entered, or may enter, the oil sands business and begin producing bitumen and SCO, or expand their existing operations. It is difficult to assess the number, level of production and ultimate timing of all potential new projects or when existing production levels may increase. During recent years, a global focus on the oil sands through increasing industry consolidation that has created competitors with financial capacity has significantly increased the supply of bitumen, SCO and heavy crude oil in the marketplace. The impact of this level of activity on regional infrastructure, including pipelines, has placed stress on the availability and cost of all resources required to build and run new and existing oil sands operations.

For Suncor's Refining and Marketing business, management expects that fluctuations in demand for refined products, margin volatility and overall marketplace competitiveness will continue. In addition, to the extent that our downstream business unit participates in new product markets, it could be exposed to margin risk and volatility from either cost and/or selling price fluctuations.

There is a risk that increased competition could cause costs to increase, put further strain on existing infrastructure and make margins for refined and unrefined products to be volatile which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Land Claims

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

Litigation Risk

There is a risk that Suncor may be subject to litigation, and claims under such ligation may be material. Various types of claims may be raised in these proceedings, including, but not limited to, environmental damage, breach of contract, product liability, antitrust, bribery and other forms of corruption, tax, patent infringement and employment matters. Litigation is subject to uncertainty and it is possible that there could be material adverse developments in pending or future cases. Unfavourable outcomes or settlements of litigation could encourage the commencement of additional litigation. Suncor may also be subject to adverse publicity associated with such matters, regardless of whether Suncor is ultimately found liable. There is a risk that the outcome of such litigation may be materially adverse and/or we may be required to incur significant expenses or devote significant resources in defence against such litigation, the success of which cannot be guaranteed.

Dividends

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

Control Environment

Based on their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only

reasonable assurance with respect to financial statement preparation and presentation. Failure to adequately prevent, detect and correct misstatements could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

DIVIDENDS

The Board of Directors has established a policy of paying dividends on a quarterly basis. We review our dividend policy from time-to-time with regard to our financial position, financing requirements for growth, cash flow and other factors which our Board of Directors considers relevant. The Board approved an increase in the quarterly dividend to $0.23 per share from $0.20 per share in the first quarter of 2014. In July 2014, the Board of Directors approved a per share increase of $0.05 to Suncor's quarterly dividend to $0.28 per common share. Dividends are paid subject to applicable law, if, as and when declared by the Board.

Year ended December 31	**2014**	2013	2012
Cash dividends per common share ($)	**1.02**	0.73	0.50

DESCRIPTION OF CAPITAL STRUCTURE

The company's authorized share capital is comprised of an unlimited number of common shares, an unlimited number of preferred shares issuable in series designated as senior preferred shares, and an unlimited number of preferred shares issuable in series designated as junior preferred shares.

As at December 31, 2014, there were 1,444,119,940 common shares issued and outstanding. To the knowledge of the Board of Directors and executive officers of Suncor, no person beneficially owns, or exercises control or direction over, securities carrying 10% or more of the voting rights attached to any class of voting securities of the company. The holders of common shares are entitled to attend all meetings of shareholders and vote at any such meeting on the basis of one vote for each common share held. Common shareholders are entitled to receive any dividend declared by the Board on the common shares and to participate in a distribution of the company's assets among its shareholders for the purpose of winding up its affairs. The holders of the common shares shall be entitled to share equally, share for share, in all distributions of such assets.

Petro-Canada Public Participation Act

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

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

Credit Ratings

The following information regarding the company's credit ratings is provided as it relates to the company's cost of funds and liquidity. In particular, the company's ability to access unsecured funding markets and to engage in certain collateralized business activities on a cost-effective basis is primarily dependent upon maintaining competitive credit ratings. A lowering of the company's credit rating may also have potentially adverse consequences for the company's funding capacity for growth projects or access to the capital markets, may affect the company's ability, and the cost, to enter into normal course derivative or hedging transactions and may require the company to post additional collateral under certain contracts.

The following table shows the ratings issued by the rating agencies noted therein as of December 31, 2014. The credit ratings are not recommendations to purchase, hold or sell the debt securities inasmuch as such ratings do not comment as to the market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

	Senior Unsecured	Outlook	Canadian Commercial Paper Program	U.S. Commercial Paper Program
Standard & Poor's (S&P)	A-	Stable	A-1 (low)	A-2
Dominion Bond Rating Service (DBRS)	A (low)	Stable	R-1 (low)	R-1 (low)
Moody's Investors Service (Moody's)	A3	Stable	Not rated	P-2

S&P credit ratings on long-term debt are on a rating scale that ranges from AAA to D, representing the range of such securities rated from highest to lowest quality. A rating of A by S&P is the third highest of 10 categories and indicates that the obligor had strong capacity to meet its financial commitments. However, the obligor is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than higher rated obligors (rated AA or AAA). The addition of a plus (+) or minus (-) designation after the rating indicates the relative standing within a particular rating category. S&P credit ratings on commercial paper are on a short-term debt rating scale that ranges from A-1 to D, representing the range of such securities rated from highest to lowest quality. A Canadian rating by S&P of A-1 (low) is the third highest of eight categories and a U.S. rating of A-2 is the second highest of six categories, indicating a slightly higher susceptibility to the adverse effects of changes in circumstances and economic conditions, although the obligor's capacity to meet its financial commitment on the obligation is satisfactory.

DBRS credit ratings on long-term debt are on a rating scale that ranges from AAA to D, representing the range of such securities rated from highest to lowest. A rating of A by DBRS is the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality, with the capacity for the payment of financial obligations being substantial, but of a lesser credit quality than an AA rating. Entities in the A category may be vulnerable to future events, but qualifying negative factors are considered manageable. All rating categories other than AAA and D also contain designations for (high) and (low). The absence of either a (high) or (low) designation indicates the rating is in the middle of the category. The assignment of a (high) or (low) designation within a rating category indicates relative standing within that category. DBRS's credit ratings on commercial paper are on a short-term debt rating scale that ranges from R-1 (high) to D, representing the range of such securities rated from highest to lowest quality. A rating of R-1 (low) by DBRS is the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality. The capacity for the payment of short-term financial obligations as they become due is substantial, with overall strength not as favourable as higher rating categories. Entities in this category may be vulnerable to future events, but qualifying negative factors are considered manageable. The R-1 and R-2 commercial paper categories are denoted by (high), (middle) and (low) designations.

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of A by Moody's is the third highest of nine categories. Obligations rated A are subject to low credit risk. They are considered upper-medium grade. For rating categories Aa through Caa, Moody's appends numerical modifiers 1, 2 or 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category. A rating of P-2 by Moody's for commercial paper is the second highest of four rating categories and indicates a strong ability to repay short-term obligations.

Suncor has paid each of S&P, DBRS and Moody's their customary fees in connection with the provision of the above ratings. Suncor has not made any payments to S&P, DBRS or Moody's in the past two years for services unrelated to the provision of such ratings.

MARKET FOR SECURITIES

Our common shares are listed on the TSX in Canada and on the NYSE in the U.S. The price ranges and the volumes traded on the TSX for the year ended December 31, 2014, are as follows:

TSX

	Price Range (Cdn$)		
	High	Low	Trading Volume (000s)
2014			
January	38.15	35.92	49 837
February	37.23	34.70	50 099
March	38.80	36.04	57 815
April	42.88	38.21	57 526
May	43.47	41.41	49 118
June	47.18	41.71	54 607
July	46.00	43.59	44 246
August	44.72	41.59	46 009
September	44.61	39.96	66 233
October	41.30	35.17	91 914
November	40.81	35.66	77 392
December	38.17	30.89	105 160

For information in respect of options to purchase common shares of Suncor and common shares issued upon the exercise of options, see the Share Capital note to the 2014 audited Consolidated Financial Statements, which is incorporated by reference into this AIF.

On November 25, 2014, Suncor issued an aggregate of US$750 million 3.60% notes due in 2024, and on November 26, 2014, Suncor issued an aggregate of $750 million 3.10% medium term notes, series 5 due in 2021.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

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

Suncor Directors Name and Jurisdiction of Residence	Period Served and Independence	Biography
Mel E. Benson[1][2] Alberta, Canada	Director since 2000 Independent	Mel Benson is president of Mel E. Benson Management Services Inc., an international consulting firm working in various countries with a focus on First Nations/corporate negotiations. Mr. Benson is also part owner of the private oil and gas company Tenax Energy Inc. and sits on the board of the Fort McKay Group of Companies, a community trust organization, as well as Oilstone Energy Services, Inc., based in Houston, Texas. Mr. Benson retired from Exxon International and Imperial Oil Canada in 2000 after a long career as an operations manager and senior member of project management. While based in Houston, Texas, Mr. Benson worked on international projects based in Africa and the former Soviet Union. Mr. Benson recently became a member of the community advisory board for the Alberta Land Institute through the University of Alberta. Mr. Benson is a member of Beaver Lake Cree Nation, located in northeast Alberta. In 2015, Mr. Benson was inducted into the Aboriginal Business Hall of Fame.
Jacynthe Côté[2][3] Quebec, Canada	Director since 2015 Independent	Jacynthe Côté was president and chief executive officer of Rio Tinto Alcan from February 2009 until June 2014 and she continued to serve in an advisory role until her retirement on September 1, 2014. Prior to 2009, she served as president and chief executive officer of Rio Tinto Alcan's Primary Metal business group, following Rio Tinto's acquisition of Alcan Inc. in October 2007. Ms. Côté joined Alcan Inc. in 1988 and she served in a variety of progressively senior leadership roles during her career, including positions in human resources, environment, health and safety, business planning and development and production/managerial positions in Quebec and England. Ms. Côté is a director of the Royal Bank of Canada and Finning International Inc. She also serves as a member of the advisory board of the Montreal Neurological Institute and of the board of directors of École des Hautes Études Commereciales Montreal. Ms. Côté has a Bachelor's degree in Chemistry from Laval University.

Dominic D'Alessandro[3][4] Ontario, Canada	Director since 2009 Independent	Dominic D'Alessandro was president and chief executive officer of Manulife Financial Corporation from 1994 to 2009 and is currently a director of CGI Group Inc. For his many business accomplishments, Mr. D'Alessandro was recognized as Canada's Most Respected CEO in 2004 and CEO of the Year in 2002, and was inducted into the Insurance Hall of Fame in 2008. Mr. D'Alessandro is an Officer of the Order of Canada and has been appointed as a Commendatore of the Order of the Star of Italy. In 2009, he received the Woodrow Wilson Award for Corporate Citizenship and in 2005 was granted the Horatio Alger Award for community leadership. Mr. D'Alessandro is a FCA, and holds a Bachelor of Science from Concordia University in Montreal. He has also been awarded honorary doctorates from York University, the University of Ottawa, Ryerson University and Concordia University.
W. Douglas Ford[1][4] Florida, USA	Director since 2004 Independent	W. Douglas Ford was chief executive, refining and marketing for BP p.l.c. ("BP") from 1998 to 2002 and was responsible for the refining, marketing and transportation network of BP as well as the aviation fuels business, the marine business and BP shipping. Mr. Ford is currently a director of Air Products and Chemicals, Inc. He is also a member of the board of trustees of the University of Notre Dame as Trustee Emeritus.
John D. Gass[1][2] Florida, USA	Director since 2014 Independent	John Gass is former vice president, Chevron Corporation, a major integrated oil and gas company, and former president, Chevron Gas and Midstream, positions he held from 2003 until his retirement in 2012. He has extensive international experience, having served in a diverse series of operational positions in the oil and gas industry with increasing responsibility throughout his career. Mr. Gass serves as a director of Southwestern Energy Co. and Weatherford International Ltd. He is also on the board of visitors for the Vanderbilt School of Engineering and is a member of the advisory board for the Vanderbilt Eye Institute. Mr. Gass graduated from Vanderbilt University in Nashville, Tennessee, with a bachelor's degree in civil engineering. He also holds a master's degree in civil engineering from Tulane University in New Orleans, Louisiana. A resident of Florida, he is a member of the American Society of Civil Engineers and the Society of Petroleum Engineers.
Paul Haseldonckx[2][3] Essen, Germany	Director since 2002 (Petro-Canada 2002 to July 31, 2009) Independent	Paul Haseldonckx was a member of the management board of Veba Oel AG (Veba), Germany's largest downstream oil and gas company, including Aral AG gas stations in Europe. Mr. Haseldonckx represented Veba's interests at the board of the Cerro Negro joint venture, an in situ oil sands development including an upgrader, during the construction and early production phase. Mr. Haseldonckx holds a Master of Science and has completed Executive Programs at INSEAD, Fontainebleau and IMD, Lausanne.

John R. Huff[1][2] Texas, USA	Director since 1998 Independent	Mr. Huff has served as chairman of the board of directors of Oceaneering International, Inc. ("Oceaneering") since 1990 and served as its chief executive officer from 1986 to 2006. Prior to joining Oceaneering, Mr. Huff served as chairman, president and chief executive officer of Western Oceanic, Inc. from 1972 to 1986. Mr. Huff also serves as a director of Hi Crush Partners LP. Mr. Huff is a member of the National Academy of Engineering. In addition, Mr. Huff is a past member of the National Petroleum Council and a past director of the National Ocean Industries Association and the International Association of Drilling Contractors, and served on the U.S. Department of Transportation's National Offshore Safety Advisory Committee. He is a past director of the American Bureau of Shipping, the U.S. Coast Guard Foundation, Law of the Sea Institute and Marine Resources Development Foundation, a past trustee of the Houston Museum of Natural Science, and past chairman of the Texas Bowl. Mr. Huff attended Rice University and received a Bachelor's degree in Civil Engineering from the Georgia Institute of Technology and attended the Harvard Business School's Program for Management Development. Mr. Huff is a registered professional engineer in the state of Texas and a member of the Explorers Club.
Jacques Lamarre[2][3] Quebec, Canada	Director since 2009 Independent	Jacques Lamarre is past president and chief executive officer of SNC-Lavalin, a position he held from May 1996 until his retirement in May 2009. Mr. Lamarre is an Officer of the Order of Canada and a founding member and past chair of the Commonwealth Business Council. He is also past chair of the board of directors of the Conference Board of Canada and a founding member of the World Economic Forum's Governors for Engineering & Construction. Currently, he serves as a director of PPP Canada Inc. and is a member of the Engineering Institute of Canada, Engineers Canada and the Ordre des ingénieurs du Québec. Mr. Lamarre holds a Bachelor of Arts and a Bachelor of Arts and Science in Civil Engineering from Université Laval in Quebec City. He also completed Harvard University's Executive Development Program. In addition, Mr. Lamarre holds honorary doctorates from the University of Waterloo, the University of Moncton and Université Laval. Among others, he has previously served on the board of the Royal Bank of Canada.

Maureen McCaw[2][3] Alberta, Canada	Director since 2004 (Petro-Canada 2004 to July 31, 2009) Independent	Maureen McCaw was most recently executive vice-president of Leger Marketing (Alberta) and formerly president of Criterion Research, a company she founded in 1986. Ms. McCaw is chair of the CBC Pension Fund Plan board of trustees and is a director of the Canadian Broadcasting Corporation, the Alberta Securities Commission and the Edmonton International Airport. She also serves on a number of other boards and advisory committees, including the Institute of Corporate Directors, the Nature Conservancy of Canada and MacEwan University, Faculty of Business, as well as being past chair of the Edmonton Chamber of Commerce. Ms. McCaw completed Columbia Business School's executive program in financial accounting and has an ICD.d.
Michael W. O'Brien[3][4] Alberta, Canada	Director since 2002 Independent	Michael O'Brien served as executive vice president, corporate development, and chief financial officer of Suncor Energy Inc. before retiring in 2002. Mr. O'Brien is a director and chair of the Audit Committee of Shaw Communications Inc. In addition, he is past chair of the board of trustees for the Nature Conservancy Canada, past chair of the Canadian Petroleum Products Institute and past chair of Canada's Voluntary Challenge for Global Climate Change. He has previously served on the boards of Teresen Inc., Primewest Energy Inc. and CRA International.
James W. Simpson Alberta, Canada	Director since 2004 (Petro-Canada 2004 to July 31, 2009) Independent	James Simpson is past president of Chevron Canada Resources (oil and gas). He serves as lead director for Canadian Utilities Limited and is on its Corporate Governance, Nomination, Compensation and Succession Committee, as well as being the chairman for its Audit Committee and Risk Review Committee. Mr. Simpson holds a Bachelor of Science and Master of Science, and graduated from the Program for Senior Executives at M.I.T.'s Sloan School of Business. He is also past chairman of the Canadian Association of Petroleum Producers and past vice chairman of the Canadian Association of the World Petroleum Congresses.
Eira M. Thomas[1][4] British Columbia, Canada	Director since 2006 Independent	Eira Thomas is a Canadian geologist with over 20 years of experience in the Canadian diamond business, including her previous roles as vice president of Aber Resources, now Dominion Diamond Corp., and as founder and CEO of Stornoway Diamond Corp. Currently, Ms. Thomas is chief executive officer and a director of Kaminak Gold Corporation, a mineral exploration company, and a director of Lucara Diamond Corp.

Steven W. Williams Alberta, Canada	Director since December 2011 Non-independent, management	Steve Williams has served as the President of Suncor Energy Inc. since December 2011 and as Chief Executive Officer of Suncor Energy Inc. since May 2012. Mr. Williams is a fellow of the Institution of Chemical Engineers and is a member of the Institute of Directors. He is also one of 12 founding CEOs of Canada's Oil Sands Innovation Alliance (COSIA), a member of the advisory board of Canada's Ecofiscal Commission, and a member of the Canadian Council of Chief Executives. He is active in the community, having recently co-chaired the 2014 Canadian Olympic Hall of Fame Gala in Calgary as part of the 2014 Celebration of Excellence in Alberta that raised proceeds for the Canadian Olympic Foundation. He also serves as co-chair of Indspire's "Building Brighter Futures Campaign".
Michael M. Wilson[3][4] Alberta, Canada	Director since 2014 Independent	Michael Wilson is former president and chief executive officer of Agrium Inc., a retail supplier of agricultural products and services and a wholesale producer and marketer of agricultural nutrients, which is headquartered in Calgary, a position he held from 2003 until his retirement in 2013. He previously served as executive vice president and chief operating officer. Mr. Wilson has significant experience in the petrochemical industry, serving as president of Methanex Corporation, and holding various positions with increasing responsibility in North America and Asia with Dow Chemical Company. Mr. Wilson has a bachelor's degree in chemical engineering from the University of Waterloo and currently serves on the boards of Celestica Inc., Finning International Inc. and Air Canada. He is also the chair of the Calgary Prostate Cancer Centre.

(1) Human Resources and Compensation Committee

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

(3) Audit Committee

(4) Governance Committee

Executive Officers

The following individuals are the executive officers of Suncor:

Name	Jurisdiction of Residence	Office
Steven W. Williams	Alberta, Canada	President and Chief Executive Officer
Alister Cowan	Alberta, Canada	Executive Vice President and Chief Financial Officer
Eric Axford	Alberta, Canada	Executive Vice President, Business Services
Mark Little	Alberta, Canada	Executive Vice President, Upstream
Mike MacSween	Alberta, Canada	Executive Vice President, Major Projects
Stephen D.L. Reynish	Alberta, Canada	Executive Vice President, Strategy & Corporate Development
Kris Smith	Ontario, Canada	Executive Vice President, Refining and Marketing
Paul Gardner	Alberta, Canada	Senior Vice President, Human Resources
Janice Odegaard	Alberta, Canada	Senior Vice President, General Counsel and Corporate Secretary

As at February 23, 2015, the directors and executive officers of Suncor as a group beneficially owned, or controlled or directed, directly or indirectly, common shares of Suncor representing 0.05% of the outstanding common shares of Suncor.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

As at the date hereof, no director or executive officer of Suncor is or has been within the last ten years a director, chief executive officer or chief financial officer of a company (including Suncor) that:

(a) was the subject of a cease trade or similar order, or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days while the director or executive officer was acting in that capacity; or

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

As at the date hereof, no director or executive officer of Suncor, or any of their respective personal holding companies, nor any shareholder holding a sufficient number of securities to affect materially the control of Suncor:

(a) is, or has been within the last ten years, a director or executive officer of any company (including Suncor) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than: (i) Mr. Ford, a director of Suncor who was a director of USG Corporation (until May 2014), which was in bankruptcy protection until June 2006, and who was also a director of United Airlines (until February 2006), which was in Chapter 11 bankruptcy protection until February 2006; and (ii) Mr. Benson, a director of Suncor who was a director of Winalta Inc. (Winalta) when it obtained an order on April 26, 2010 from the Alberta Court of Queen's Bench providing for creditor protection under the *Companies' Creditors Arrangement Act* (Canada). A plan of arrangement for Winalta received court confirmation later that year, and Mr. Benson ceased to be a director of Winalta in May 2013; or

(b) has, within the last ten years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

No director or executive officer of Suncor has been subject to:

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

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

AUDIT COMMITTEE INFORMATION

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

Composition of the Audit Committee

The Audit Committee is comprised of Mr. O'Brien (Chair), Ms. Côté, Mr. D'Alessandro, Mr. Haseldonckx, Mr. Lamarre, Ms. McCaw and Mr. Wilson. All members are independent and financially literate. The education and expertise of each member is described in the Directors and Executive Officers section of this AIF.

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

Financial Literacy

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

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

Audit Committee Financial Expert

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

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

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

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

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

(e) an understanding of audit committee functions.

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

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

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

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

(d) other relevant experience.

Audit Committee Pre-Approval Policies for Non-Audit Services

Our Audit Committee has considered whether the provision of services other than audit services is compatible with maintaining our auditors' independence and has a policy governing the provision of these services. A copy of our policy relating to Audit Committee approval of fees paid to our auditors, in compliance with the *Sarbanes-Oxley Act of 2002* and applicable Canadian law, is attached as Schedule "B" to this AIF.

Fees Paid to Auditors

Fees paid or payable to PricewaterhouseCoopers LLP, the company's auditors are as follows:

($ thousands)	**2014**	2013
Audit Fees	**6 590**	6 108
Audit-Related Fees	**497**	519
Tax Fees	**90**	50
All Other fees	**15**	60
Total	**7 192**	6 737

Audit Fees were paid, or are payable, for professional services rendered by the auditors for the audit of Suncor's annual financial statements, or services provided in connection with statutory and regulatory filings or engagements. Audit-Related Fees were paid for professional services rendered by the auditors for the review of quarterly financial statements and for the preparation of reports on specified procedures as they relate to audits of joint arrangements and attest services not required by statute or regulation. Tax Fees for corporate tax filings and tax planning were paid in a foreign jurisdiction where Suncor has limited activity. All Other Fees were subscriptions to auditor-provided and supported tools. All services described beside the captions "Audit Fees", "Audit-Related Fees", "Tax Fees" and "All Other Fees" were approved by the Audit Committee in compliance with paragraph (c)(7)(i) of Rule 2-01 of Regulation S-X under the *U.S. Securities and Exchange Act of 1934* , as amended (the Exchange Act). None of the fees described above were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Regulation S-X under the Exchange Act.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings in respect of which we are or were a party, or in respect of which any of our property is or was the subject during the year ended December 31, 2014, nor are there any such proceedings known by us to be contemplated, that involve a claim for damages exceeding 10% of our current assets. In addition, there have not been any (a) penalties or sanctions imposed against the company by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2014, (b) any other penalties or sanctions imposed by a court or regulatory body against the company that would likely be considered important to a reasonable investor in making an investment decision, or (c) settlement agreements entered into by the company before a court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2014.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer, or any associate or affiliate of these persons has, or has had, any material interest, direct or indirect, in any transaction or any proposed transaction that has materially affected or is reasonably expected to materially affect us within the three most recently completed financial years or during the current financial year.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

During the year ended December 31, 2014, we did not enter into any contracts, nor are there any contracts still in effect, that are material to our business, other than contracts entered into in the ordinary course of business, which are not required to be filed by Section 12.2 of National Instrument 51-102 *Continuous Disclosure Obligations*.

INTERESTS OF EXPERTS

Reserves and resources estimates contained in this AIF are based in part upon reports prepared by GLJ and Sproule, Suncor's independent qualified reserves evaluators. As at the date hereof, none of the partners, employees or consultants of GLJ or Sproule, respectively, as a group, through registered or beneficial interests, direct or indirect, held or are entitled to receive more than 1% of any class of our outstanding securities, including the securities of our associates and affiliates.

The company's independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditor's report dated February 24, 2015 in respect of the company's Consolidated Financial Statements, which comprise the Consolidated Balance Sheets as at December 31, 2014 and December 31, 2013 and the Consolidated Statements of Comprehensive Income, Changes in Shareholders' Equity and Cash Flows for the years ended December 31, 2014 and December 31, 2013, and the related notes, and the report on internal control over financial reporting as at December 31, 2014. PricewaterhouseCoopers LLP has advised that they are independent with respect to the company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the United States Securities and Exchange Commission.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian issuer listed on the NYSE, we are not required to comply with most of the NYSE's rules and instead may comply with Canadian requirements. As a foreign private issuer, we are only required to comply with four of the NYSE's rules. These rules provide that: (i) Suncor must have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act; (ii) the Chief Executive Officer of Suncor must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE rules; (iii) Suncor must provide a brief description of any significant differences between our corporate governance practices and those followed by U.S. companies listed under the NYSE; and (iv) Suncor must provide annual, and as required, written affirmations of compliance with applicable NYSE Corporate Governance rules.

The company has disclosed in its 2015 management proxy circular, which is available on our website at www.suncor.com, significant areas which the company does not comply with the NYSE Corporate Governance Standards. In certain instances, it is not required to obtain shareholder approval for material amendments to equity compensation plans under TSX requirements, while the NYSE requires shareholder approval of all equity compensation plans. Suncor, while in compliance with the independence requirements of applicable securities laws in Canada (specifically National Instrument 52-110 Audit Committees) and the U.S. (specifically Rule 10A-3 of the Exchange Act), has not adopted, and is not required to adopt, the director independence standards contained in Section 303A.02 of the NYSE's Listed Company Manual, including with respect to its audit committee and compensation committee. The Board has not adopted, nor is it required to adopt, procedures to implement Section 303A.05(c)(iv) of the NYSE's Listed Company Manual in respect of compensation committee advisor independence. Except as described herein, the company is in compliance with the NYSE Corporate Governance standards in all other significant respects.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities, and securities authorized for issuance under equity compensation plans, where applicable, is contained in our most recent management proxy circular for our most recent annual meeting of our shareholders that involved the election of directors. Additional financial information is provided in our 2014 audited Consolidated Financial Statements for our most recently completed financial year and in the MD&A.

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

ADVISORY – FORWARD-LOOKING INFORMATION AND NON-GAAP FINANCIAL MEASURES

This AIF contains certain forward-looking statements and forward-looking information (collectively, forward-looking statements) within the meaning of applicable Canadian and U.S. Securities laws and other information based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of information available at the time the statement was made and consider Suncor's experience and its perception of historical trends, including expectations and assumptions concerning: the accuracy of reserves and resources estimates; commodity prices and interest and foreign exchange rates; capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and third-party approvals. In addition, all other statements and other information that address expectations or projections about the future, and other statements and information about Suncor's strategy for growth, expected and future expenditures or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and the expected impact of future commitments are forward-looking statements. Some of the forward-looking statements and information may be identified by words like "expects", "anticipates", "will", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", "continue", "should", "may" and similar expressions.

Forward-looking statements in this AIF include references to:

Suncor's expectations about production volumes and the performance and costs of its assets, including:

- *The estimated gross oil production capacity of Hebron is 150,000 bbls/d (34,000 bbls/d net to Suncor) and that the project will include 1,200 mbbls of oil storage capacity and 52 well slots with first oil expected in 2017. Suncor's share of the post-sanction project cost estimate is expected to be approximately $2.8 billion;*
- *Golden Eagle is expected to ramp up to its peak production rate of approximately 70,000 boe/d (18,000 boe/d net to Suncor) during 2015 and the estimated gross development cost for the project is expected to be approximately $1.0 billion net to Suncor;*
- *Designs for the Fort Hills mining project, including the plan for 180,000 bbls/d (73,000 bbls/d net to Suncor) of bitumen production capacity, the use of paraffinic froth treatment and the expectation the project will reach 90% of its planned capacity within its first year. Suncor's shares of post-sanction project costs are estimated to be $5.5 billion, and that $1.6 billion is expected to be spent on activities for the project in 2015;*
- *Preliminary designs for the Joslyn North mining project plan for 157 mbbls/d of bitumen production (gross); and*
- *TRO$_{TM}$ is expected to accelerate and improve the company's tailings management processes, eliminate the need for new tailings ponds at existing mining operations, and, in the years ahead, reduce the number of tailings ponds.*

The anticipated duration and impact of planned maintenance events, including:

- *The next scheduled turnaround at Oil Sands operations will be in 2016.*

Suncor's expectations about capital expenditures, and growth and other projects, including:

- *The expectation that Suncor's waste water treatment plant will increase the reuse and recycling of wastewater from Suncor's upgrading operations and reduce freshwater withdrawal;*
- *The WTDC is expected to connect to Suncor's Firebag operations, provide an environment to test water treatment and recycling technologies and is scheduled to become operational in early 2017;*
- *Suncor believes Voyageur South and Audet can be developed using mining techniques;*
- *Drilling activities, including plans for the winter 2015 In Situ drilling programs (which are designed to identify sufficient resources to fill facilities associated with Suncor's replication strategy) at Lewis (100 core wells) and Meadow Creek (68 core holes) and the expectation that a development application will be filed with the AER in 2015 around Suncor's replication strategy;*
- *Suncor's greenfield growth plans, starting with Meadow Creek, and its replication strategies to build standardized surface facilities, well pads and infrastructure;*
- *Syncrude's plans to develop two mining areas adjacent to the current mine, which would consequently extend the life of Mildred Lake by approximately ten years;*
- *Project activities for Fort Hills in 2015, which are expected to focus on the secondary extraction and utilities areas, the continued ramp-up of field construction activities, and procurement spending across all areas;*
- *Expectations around Suncor's new technology projects, including oxy-fuel combustion, zero liquid discharge, ESEIEH, N-SOLV $_{TM}$ and SAGD Lite;*

- *Current development plans for HSEU, including the drilling of two additional development wells from the GBS platform and five additional water injection wells in the excavated subsea drill centre;*
- *Production from the HSEU is expected to reach higher rates in 2015;*
- *First oil is anticipated in the second quarter of 2015 for the White Rose Extensions;*
- *Expectations around exploration and appraisal initiatives in the North Sea and offshore Newfoundland and Nova Scotia, including drilling plans around these assets;*
- *Suncor's sulphur recovery plant in Montreal is expected to secure the refinery's long-term sulphur recovery needs; and*
- *The Cedar Point project's commercial operations are expected to begin later in 2015 and add 100 MW of gross generating capacity.*

Also:

- *Significant development activities and costs anticipated to occur or be incurred in 2015, including those identified under the Future Development Costs table in the Statement of Reserves Data and Other Oil and Gas Information section contained herein;*
- *Suncor's belief that internally generated cash flows, existing and future credit facilities, and access to debt capital markets are sufficient to fund future development costs and that interest or other funding costs would not make development of any property uneconomical;*
- *Anticipated abandonment and reclamations costs;*
- *The expectation that the Aurora South mining area will not come on-stream before 2024;*
- *Suncor's plans around its reserves and resources, including anticipated development activities for 2015 and beyond;*
- *Production estimates for 2015;*
- *Anticipated royalty and income tax rates and the impact of these rates on Suncor; and*
- *Anticipated effects of environmental and climate change legislation, including Suncor's expected compliance costs.*

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

The financial and operating performance of the company's reportable operating segments, specifically Oil Sands, Exploration and Production, and Refining and Marketing, may be affected by a number of factors.

Factors that affect our Oil Sands segment include, but are not limited to, volatility in the prices for crude oil and other production, and the related impacts of fluctuating light/heavy and sweet/sour crude oil differentials; changes in the demand for refinery feedstock and diesel fuel, including the possibility that refiners that process our proprietary production will be closed, experience equipment failure or other accidents; our ability to operate our Oil Sands facilities reliably in order to meet production targets; the output of newly commissioned facilities, the performance of which may be difficult to predict during initial operations; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; our dependence on pipeline capacity and other logistical constraints, which may affect our ability to distribute our products to market; our ability to finance Oil Sands growth and sustaining capital expenditures; the availability of bitumen feedstock for upgrading operations, which can be negatively affected by poor ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage, and in situ reservoir and equipment performance, or the unavailability of third-party bitumen; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; our ability to complete projects, including planned maintenance events, both on time and on budget, which could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Alberta's Wood Buffalo region and the surrounding area (including housing, roads and schools); risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; changes to royalty and tax legislation and related agreements that could impact our business; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and changes to environmental regulations or legislation.

Factors that affect our Exploration and Production segment include, but are not limited to, volatility in crude oil and natural gas prices; operational risks and uncertainties associated with oil and gas activities, including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, and pollution and other environmental risks; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; adverse weather conditions, which could disrupt output from producing assets or impact drilling programs, resulting

in increased costs and/or delays in bringing on new production; political, economic and socio-economic risks associated with Suncor's foreign operations, including the unpredictability of operating in Libya and that operations in Syria continue to be impacted by sanctions or political unrest; risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and market demand for mineral rights and producing properties, potentially leading to losses on disposition or increased property acquisition costs.

Factors that affect our Refining and Marketing segment include, but are not limited to, fluctuations in demand and supply for refined products that impact the company's margins; market competition, including potential new market entrants; our ability to reliably operate refining and marketing facilities in order to meet production or sales targets; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; risks and uncertainties affecting construction or planned maintenance schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period; and the potential for disruptions to operations and construction projects as a result of our relationships with labour unions or employee associations that represent employees at our refineries and distribution facilities.

Additional risks, uncertainties and other factors that could influence the financial and operating performance of all of Suncor's operating segments and activities include, but are not limited to, changes in general economic, market and business conditions, such as commodity prices, interest rates and currency exchange rates; fluctuations in supply and demand for Suncor's products; the successful and timely implementation of capital projects, including growth projects and regulatory projects; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; actions by government authorities, including the imposition or reassessment of taxes or changes to fees and royalties, such as the NORs received by Suncor from the CRA, Ontario, Alberta and Quebec relating to the settlement of certain derivative contracts, including the risk that: (i) Suncor may not be able to successfully defend its original filing position and ultimately be required to pay increased taxes, interest and penalty as a result; or (ii) Suncor may be required to post cash instead of security in relation to the NORs; changes in environmental and other regulations; the ability and willingness of parties with whom we have material relationships to perform their obligations to us; outages to third-party infrastructure that could cause disruptions to production; the occurrence of unexpected events such as fires, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; the potential for security breaches of Suncor's information systems by computer hackers or cyberterrorists, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; our ability to find new oil and gas reserves that can be developed economically; the accuracy of Suncor's reserves, resources and future production estimates; market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; maintaining an optimal debt to cash flow ratio; the success of the company's risk management activities using derivatives and other financial instruments; the cost of compliance with current and future environmental laws; risks and uncertainties associated with closing a transaction for the purchase or sale of an oil and gas property, including estimates of the final consideration to be paid or received, the ability of counterparties to comply with their obligations in a timely manner and the receipt of any required regulatory or other third-party approvals outside of Suncor's control that are customary to transactions of this nature; and the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering that is needed to reduce the margin of error and increase the level of accuracy. The foregoing important factors are not exhaustive.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout this AIF, including under the heading Risk Factors, and the company's management's discussion and analysis dated February 26, 2015 and Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

Non-GAAP Financial Measures – Oil Sands Cash Operating Costs

Oil Sands cash operating costs and cash operating costs per barrel are non-GAAP financial measures, which are calculated by adjusting Oil Sands segment operating, selling and general expense (a GAAP measure based on sales volumes) for i) non-production costs that management believes do not relate to the production performance of Oil Sands operations, including, but not limited to, share-based compensation adjustments, costs related to the remobilization or deferral of growth projects, research, the expense recorded as part of a non-monetary arrangement involving a third-party processor, and feedstock costs for natural gas used to create hydrogen for secondary upgrading processes; ii) revenues associated with excess capacity, including excess power generated and sold that is recorded in operating revenue; and iii) the impacts of changes in inventory levels, such that the company is able to present cost information based on production volumes.

SCHEDULE "A"
AUDIT COMMITTEE MANDATE

The Audit Committee

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

Objectives

The Audit Committee assists the Board of Directors by:

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

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

(c) reviewing the effectiveness of the internal auditors, excluding the Operations Integrity Audit department, which is specifically within the mandate of the Environment, Health & Safety Committee (references throughout this mandate to "Internal Audit" shall not include the Operations Integrity Audit department); and

(d) approving on behalf of the Board of Directors certain financial matters as delegated by the Board, including the matters outlined in this mandate.

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

Constitution

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

Functions and Responsibilities

The Audit Committee has the following functions and responsibilities:

Internal Controls

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

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

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

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

5. Periodically review management's governance processes for information technology resources, to assess their effectiveness in addressing the integrity, the protection and the security of the Corporation's electronic information systems and records.

6. Review the management practices overseeing officers' expenses and perquisites.

External and Internal Auditors

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

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

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

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

11. Review and approve the appointment or termination of the Head of Internal Audit, annually review a summary of the remuneration of the Head of Internal Audit, and periodically review the performance and effectiveness of the Internal Audit function including compliance with The Institute of Internal Auditors' International Professional Practices Framework for Internal Auditing.

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

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

Financial Reporting and other Public Disclosure

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

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

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

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

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

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

Oil and Gas Reserves

20. Review with reasonable frequency Suncor's procedures for:

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

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

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

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

Risk Management

23. Periodically review the policies and practices of the Corporation respecting cash management, financial derivatives, financing, credit, insurance, taxation, commodities trading and related matters. Oversee the Board's risk management governance model by conducting periodic reviews with the objective of appropriately reflecting the principal risks of the Corporation's business in the mandate of the Board and its committees. Conduct periodic review of and provide oversight on the specific Suncor Principal Risks which have been delegated to the Committee for oversight.

Pension Plan

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

Security

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

Other Matters

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

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

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

Reporting to the Board

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

Approved by resolution of the Board of Directors on November 19, 2013

SCHEDULE "B" – SUNCOR ENERGY INC. POLICY AND PROCEDURES FOR PRE-APPROVAL OF AUDIT AND NON-AUDIT SERVICES

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

I. Statement of Policy

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

II. Responsibility

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

III. Definitions

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

(a) Audit Services include services that are a necessary part of the annual audit process and any activity that is a necessary procedure used by the auditor in reaching an opinion on the financial statements as is required under generally accepted auditing standards (GAAS), including technical reviews to reach audit judgment on accounting standards. The term Audit Services is broader than those services strictly required to perform an audit pursuant to GAAS and include such services as:

- (i) The issuance of comfort letters and consents in connections with offerings of securities;
- (ii) The performance of domestic and foreign statutory audits;
- (iii) Attest services required by statute or regulation;
- (iv) Internal control reviews; and
- (v) Assistance with and review of documents filed with the Canadian Securities Administrators, the SEC and other regulators having jurisdiction over Suncor and its subsidiaries, and responding to comments from such regulators;

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

Audit-Related Services include:

- (i) Employee benefit plan audits, including audits of employee pension plans;
- (ii) Due diligence related to mergers and acquisitions;
- (iii) Consultations and audits in connection with acquisitions, including evaluating the accounting treatment for proposed transactions;
- (iv) Internal control reviews;
- (v) Attest services not required by statute or regulation; and
- (vi) Consultations regarding financial accounting and reporting standards.

Non-financial operational audits are not Audit-Related Services.

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

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

IV. General Policy

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

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

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

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

- The Chairman of the Audit Committee may delegate his authority to pre-approve services to another sitting member of the Audit Committee provided that the recipient has also been delegated the authority to act as Chairman of the Audit Committee in the Chairman's absence. A resolution of the Audit Committee is required to evidence the Chairman's delegation of authority to another Audit Committee member under this policy.

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

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

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

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

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

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

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

  (a) Be in writing and signed by the auditors;

  (b) Specify the particular services to be provided;

  (c) Specify the period in which the services will be performed;

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

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

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

V. Responsibilities of External Auditors

To support the independence process, the independent auditors will:

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

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

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

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

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

In addition, the external auditors will:

(f) Provide regular, detailed fee reporting including balances in the work in progress account; and

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

VI. Disclosures

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

Approved and Accepted April 28, 2004

Appendix A – Prohibited Non-Audit Services

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

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

- Maintaining or preparing the audit client's accounting records;
- Preparing Suncor's financial statements that are filed with the SEC or that form the basis of financial statements filed with the SEC; or
- Preparing or originating source data underlying Suncor's financial statements.

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

- Directly or indirectly operating, or supervising the operation of, Suncor's information systems or managing Suncor's local area network; or
- Designing or implementing a hardware or software system that aggregates source data underlying the financial statements or generates information that is significant to Suncor's financial statements or other financial information systems taken as a whole.

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

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

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

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

Human resources. Any of the following:

- Searching for or seeking out prospective candidates for managerial, executive, or director positions;
- Engaging in psychological testing, or other formal testing or evaluation programs;
- Undertaking reference checks of prospective candidates for an executive or director position;
- Acting as a negotiator on Suncor's behalf, such as determining position, status or title, compensation, fringe benefits, or other conditions of employment; or
- Recommending, or advising Suncor to hire a specific candidate for a specific job (except that an accounting firm may, upon request by Suncor, interview candidates and advise Suncor on the candidate's competence for financial accounting, administrative, or control positions).

Broker-dealer, investment adviser or investment banking services. Acting as a broker-dealer (registered or unregistered), promoter, or underwriter, on behalf of Suncor, making investment decisions on behalf of Suncor or otherwise having discretionary authority over Suncor's investments, executing a transaction to buy or sell Suncor's investment, or having custody of Suncor's assets, such as taking temporary possession of securities purchased by Suncor.

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

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

Appendix B – Pre-Approval Request Form

NATURE OF WORK	ESTIMATED FEES (Cdn$)
Total	

Date

Signature

SCHEDULE "C" – FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

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

1. We have evaluated the Company's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2014, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenues (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenues Before Income Taxes ($ millions, discounted at 10%)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	Oil Sands In Situ January 19, 2015	Canada	—	22 212	—	22 212
GLJ Petroleum Consultants Ltd.	Oil Sands Mining January 8, 2015	Canada	—	18 760	—	18 760
			—	40 972	—	40 972

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

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

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 26, 2015

"Caralyn P. Bennett"

Caralyn P. Bennett, P.Eng.
Vice-President

SCHEDULE "D" – FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

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

1. We have evaluated the Company's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2014, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenues (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenues Before Income Taxes ($ millions, discounted at 10%)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	East Coast Canada February 20, 2015	Newfoundland Offshore, Canada	— —	8 095	— —	8 095
Sproule Associates Limited	North America Onshore February 20, 2015	Western Canada	—	78	—	78
Sproule International Limited	North Sea February 20, 2015	North Sea, United Kingdom	—	5 895	—	5 895
Sproule International Limited	Other International February 20, 2015	Libya	—	3 998	—	3 998
			—	18 066	—	18 066

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

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

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

EXECUTED as to our report referred to above:

Sproule Associates Limited and Sproule International Limited, Calgary, Alberta, Canada, February 26, 2015

"Harry J. Helwerda"

Harry J. Helwerda, P.Eng., FEC, FGC (Hon.)
President and Director

SCHEDULE "E" – FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Suncor Energy Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2014, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The reports of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

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

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

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

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

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

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

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

"*Steven W. Williams*"

STEVEN W. WILLIAMS
President and Chief Executive Officer

"*Alister Cowan*"

ALISTER COWAN
Executive Vice President and Chief Financial Officer

"*James Simpson*"

JAMES SIMPSON
Chair of the Board of Directors

"*Michael W. O'Brien*"

MICHAEL W. O'BRIEN
Chair of the Audit Committee

February 26, 2015

Suncor Energy Inc.
150 - 6 Avenue S.W., Calgary, Alberta, Canada T2P 3E3
T: 403 296 8000

suncor.com

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

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

B. Consent to Service of Process

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

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

See pages 72 and 73 of Exhibit 99-1 and page 61 of Exhibit 99-2.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See pages 74 and 75 of Exhibit 99-1.

AUDIT COMMITTEE FINANCIAL EXPERT

See pages 78 and 79 of Annual Information Form.

CODE OF ETHICS

See page 25 of Annual Information Form.

FEES PAID TO PRINCIPAL ACCOUNTANT

See pages 79 of Annual Information Form.

AUDIT COMMITTEE PRE-APPROVAL POLICIES

See Schedule "B" of Annual Information Form.

APPROVAL OF NON-AUDIT SERVICES

See Schedule "B" of Annual Information Form.

OFF-BALANCE SHEET ARRANGEMENTS

See page 50 of Exhibit 99-2.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 50 of Exhibit 99-2.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 78 of Annual Information Form.

SIGNATURES

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

SUNCOR ENERGY INC.

DATE: February 26, 2015

PER: /s/ ALISTER COWAN

Alister Cowan
Executive Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Description
99-1	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2014
99-2	Management's Discussion and Analysis for the fiscal year ended December 31, 2014, dated February 26, 2015
99-3	Consent of PricewaterhouseCoopers LLP
99-4	Consent of GLJ Petroleum Consultants Ltd.
99-5	Consent of Sproule Associates Limited, Sproule Unconventional Limited and Sproule International Limited
99-6	Certificate of Chief Executive Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-7	Certificate of the Chief Financial Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-8	Certificate of the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99-9	Certificate of the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99-10	Supplementary Oil and Gas Disclosures (unaudited)

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UNDERTAKING AND CONSENT TO SERVICE OF PROCESS
DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING
ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM
AUDIT COMMITTEE FINANCIAL EXPERT
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EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2014

MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL REPORTING

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

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles applicable to publically accountable enterprises, which is within the framework of International Financial Reporting Standards as issued by the International Accounting Standards Board incorporated into the CICA Handbook Part 1. They include certain amounts that are based on estimates and judgments.

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

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

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





Steve W. Williams
President and Chief Executive Officer

Alister Cowan
Executive Vice President and Chief Financial Officer

February 24, 2015

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

2. Management has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework (2013) in Internal Control – Integrated Framework to evaluate the effectiveness of the company's internal control over financial reporting.

3. Management has assessed the effectiveness of the company's internal control over financial reporting as at December 31, 2014, and has concluded that such internal control over financial reporting was effective as of that date. Additionally, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as at December 31, 2014. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

4. The effectiveness of the company's internal control over financial reporting as at December 31, 2014 has been audited by PricewaterhouseCoopers LLP, independent auditor, as stated in their report which appears herein.



Steve W. Williams
President and Chief Executive Officer



Alister Cowan
Executive Vice President and Chief Financial Officer

February 24, 2015

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of
Suncor Energy Inc.

We have completed the integrated audits of Suncor Energy Inc.'s 2014 and 2013 consolidated financial statements and its internal control over financial reporting as at December 31, 2014. Our opinions, based on our audits are presented below.

Report on the consolidated financial statements

We have audited the accompanying consolidated financial statements of Suncor Energy Inc., which comprise the consolidated balance sheets as at December 31, 2014 and December 31, 2013, and the consolidated statements of comprehensive income, cash flows, and changes in shareholders' equity for each of the two years in the period ended December 31, 2014, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Suncor Energy Inc. as at December 31, 2014 and December 31, 2013 and its financial performance and its cash flows for each of the two years in the period ended December 31, 2014 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on internal control over financial reporting

We have also audited Suncor Energy Inc.'s internal control over financial reporting as at December 31, 2014, based on criteria established in Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting

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

Auditor's responsibility

Our responsibility is to express an opinion on Suncor Energy Inc.'s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

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

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

Definition of internal control over financial reporting

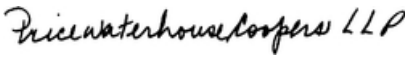
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal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

Inherent limitations

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

Opinion

In our opinion, Suncor Energy Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2014, based on criteria established in Internal Control – Integrated Framework (2013) issued by COSO.



Chartered Accountants
Calgary, Alberta

February 24, 2015

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 ($ millions)	Notes	2014	2013
Revenues and Other Income			
Operating revenues, net of royalties	7	**39 862**	39 593
Other income	8	**628**	704
		40 490	40 297
Expenses			
Purchases of crude oil and products		**17 426**	17 293
Operating, selling and general	9 and 26	**9 749**	9 462
Transportation		**879**	845
Depreciation, depletion, amortization and impairment	10 and 17	**6 140**	4 892
Exploration		**367**	322
Gain on disposal of assets	35	**(90)**	(137)
Voyageur upgrader project charges	33	**—**	82
Financing expenses	11	**1 429**	1 162
		35 900	33 921
Earnings before Income Taxes		**4 590**	6 376
Income Taxes	12		
Current		**2 115**	2 083
Deferred		**(224)**	382
		1 891	2 465
Net Earnings		**2 699**	3 911
Other Comprehensive Income			
Items That May be Subsequently Reclassified to Earnings:			
Foreign currency translation adjustment		**304**	325
Unrealized gain on assets available for sale, net of income taxes of $13	36	**85**	—
Items That Will Not be Reclassified to Earnings:			
Actuarial (loss) gain on employee retirement benefit plans, net of income taxes of $56		**(144)**	579
Other Comprehensive Income		**245**	904
Total Comprehensive Income		**2 944**	4 815
Per Common Share (dollars)	13		
Net earnings – basic		**1.84**	2.61

Net earnings – diluted	**1.84**	2.60
Cash dividends	**1.02**	0.73

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

($ millions)	Notes	December 31 2014	December 31 2013
Assets			
Current assets			
Cash and cash equivalents	14	**5 495**	5 202
Accounts receivable		**4 275**	5 254
Inventories	16	**3 466**	3 944
Income taxes receivable		**680**	294
Total current assets		**13 916**	14 694
Property, plant and equipment, net	17, 33, 34 and 35	**59 800**	57 270
Exploration and evaluation	18	**2 248**	2 772
Other assets	19	**598**	422
Goodwill and other intangible assets	20	**3 083**	3 092
Deferred income taxes	12	**26**	65
Total assets		**79 671**	78 315
Liabilities and Shareholders' Equity			
Current liabilities			
Short-term debt	21	**806**	798
Current portion of long-term debt	21	**34**	457
Accounts payable and accrued liabilities		**5 704**	7 090
Current portion of provisions	24	**752**	998
Income taxes payable		**1 058**	1 263
Total current liabilities		**8 354**	10 606
Long-term debt	21	**12 489**	10 203
Other long-term liabilities	22	**1 787**	1 464
Provisions	24	**4 895**	4 078
Deferred income taxes	12	**10 543**	10 784
Shareholders' equity		**41 603**	41 180
Total liabilities and shareholders' equity		**79 671**	78 315

The accompanying notes are an integral part of the consolidated financial statements.

Approved on behalf of the Board of Directors:





Steve W. Williams
Director

Michael W. O'Brien
Director

February 24, 2015

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	Notes	2014	2013
Operating Activities			
Net earnings		**2 699**	3 911
Adjustments for:			
Depreciation, depletion, amortization and impairment		**6 140**	4 892
Deferred income taxes		**(224)**	382
Accretion		**198**	192
Unrealized foreign exchange loss on U.S. dollar denominated debt		**839**	605
Change in fair value of derivative contracts		**(270)**	95
Gain on disposal of assets		**(90)**	(137)
Share-based compensation		**106**	214
Exploration		**104**	82
Settlement of decommissioning and restoration liabilities		**(364)**	(423)
Other		**(80)**	(401)
(Increase) decrease in non-cash working capital	15	**(122)**	688
Cash flow provided by operating activities		**8 936**	10 100
Investing Activities			
Capital and exploration expenditures		**(6 961)**	(6 777)
Acquisitions	33 and 34	**(121)**	(515)
Proceeds from disposal of assets	35	**224**	943
Divestiture of pipeline contract	24	**—**	(76)
Other investments		**(64)**	(18)
Increase (decrease) in non-cash working capital	15	**59**	(90)
Cash flow used in investing activities		**(6 863)**	(6 533)
Financing Activities			
Net change in debt		**(81)**	138
Repayment of long-term debt		**(452)**	(312)
Issuance of long-term debt		**1 575**	—
Issuance of common shares under share option plans		**247**	112
Purchase of common shares for cancellation, net of option premiums	25	**(1 671)**	(1 675)
Dividends paid on common shares		**(1 490)**	(1 095)
Cash flow used in financing activities		**(1 872)**	(2 832)

Increase in Cash and Cash Equivalents	**201**	735
Effect of foreign exchange on cash and cash equivalents	**92**	82
Cash and cash equivalents at beginning of year	**5 202**	4 385
Cash and Cash Equivalents at End of Year	**5 495**	5 202

Supplementary Cash Flow Information		
Interest paid	**752**	711
Income taxes paid	**2 697**	1 339

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

($ millions)	Notes	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total	Number of Common Shares (thousands)
At December 31, 2012		19 945	579	(210)	18 901	39 215	1 523 057
Net earnings		—	—	—	3 911	3 911	—
Foreign currency translation adjustment		—	—	325	—	325	—
Actuarial gain on employee retirement benefit plans, net of income taxes of $201		—	—	—	579	579	—
Total comprehensive income		—	—	325	4 490	4 815	—
Issued under share option plans		159	(32)	—	—	127	4 750
Issued under dividend reinvestment plan		28	—	—	(28)	—	—
Purchase of common shares for cancellation	25	(648)	—	—	(1 027)	(1 675)	(49 492)
Change in liability for share purchase commitment	25	(89)	—	—	(169)	(258)	—
Share-based compensation		—	51	—	—	51	—
Dividends paid on common shares		—	—	—	(1 095)	(1 095)	—
At December 31, 2013		19 395	598	115	21 072	41 180	1 478 315
Net earnings		**—**	**—**	**—**	**2 699**	**2 699**	**—**
Foreign currency translation adjustment		**—**	**—**	**304**	**—**	**304**	**—**
Unrealized gain on assets available for sale, net of income taxes of $13		**—**	**—**	**85**	**—**	**85**	**—**
Actuarial loss on employee retirement benefit plans, net of income taxes of $56		**—**	**—**	**—**	**(144)**	**(144)**	**—**
Total comprehensive income		**—**	**—**	**389**	**2 555**	**2 944**	**—**
Issued under share option plans		**323**	**(31)**	**—**	**—**	**292**	**7 831**
Issued under dividend reinvestment plan		**38**	**—**	**—**	**(38)**	**—**	**—**
Purchase of common shares for cancellation	25	**(553)**	**—**	**—**	**(1 118)**	**(1 671)**	**(42 027)**
Change in liability for share purchase commitment	25	**108**	**—**	**—**	**198**	**306**	**—**
Share-based compensation		**—**	**42**	**—**	**—**	**42**	**—**
Dividends paid on common shares		**—**	**—**	**—**	**(1 490)**	**(1 490)**	**—**
At December 31, 2014		**19 311**	**609**	**504**	**21 179**	**41 603**	**1 444 119**

The accompanying notes are an integral part of the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. REPORTING ENTITY AND DESCRIPTION OF THE BUSINESS

Suncor Energy Inc. (Suncor or the company) is an integrated energy company headquartered in Canada. Suncor's operations include oil sands development and upgrading, onshore and offshore oil and gas production, petroleum refining, and product marketing primarily under the Petro-Canada brand. The consolidated financial statements of the company comprise the company and its subsidiaries and the company's interests in associates and joint arrangement entities.

The address of the company's registered office is 150 – 6th Avenue S.W., Calgary, Alberta, Canada, T2P 3E3.

2. BASIS OF PREPARATION

(a) Statement of Compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and Canadian generally accepted accounting principles (GAAP) as contained within Part 1 of the Canadian Institute of Chartered Professional Accountants Handbook.

Suncor's accounting policies are based on IFRS issued and outstanding for all periods presented in these consolidated financial statements. These consolidated financial statements were approved by the Board of Directors on February 24, 2015.

(b) Basis of Measurement

The consolidated financial statements are prepared on a historical cost basis except as detailed in the accounting policies disclosed in note 3. The accounting policies described in note 3 have been applied consistently to all periods presented in these consolidated financial statements.

(c) Functional Currency and Presentation Currency

These consolidated financial statements are presented in Canadian dollars, which is the company's functional currency.

(d) Use of Estimates, Assumptions and Judgments

The timely preparation of financial statements requires that management make estimates and assumptions and use judgments. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates and judgments used in the preparation of the consolidated financial statements are described in note 4.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation

The company consolidates its interest in entities it controls. Control comprises the power to govern an entity's financial and operating policies to obtain benefits from its activities, and is a matter of judgment. Suncor recognizes its share of assets, liabilities, revenue and expenses, on a line-by-line basis, of its joint operations. Joint ventures are investments in entities over which the company has joint control over the entities net assets and are accounted for using the equity method. All intercompany balances and transactions are eliminated in preparing the consolidated financial statements.

(b) Foreign Currency Translation

Functional currencies of the company's individual entities are the currency of the primary economic environment in which the entity operates. Transactions in foreign currencies are translated to the appropriate functional currency at foreign exchange rates that approximate those on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the appropriate functional currency at foreign exchange rates at the balance sheet date. Foreign exchange differences arising on translation are recognized in net earnings. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction.

In preparing the company's consolidated financial statements, the financial statements of each entity are translated into Canadian dollars. The assets and liabilities of foreign operations are translated into Canadian dollars at exchange rates at the balance sheet date. Revenues and expenses of foreign operations are translated into Canadian dollars using foreign

exchange rates that approximate those on the date of the underlying transaction. Foreign exchange differences are recognized in Other Comprehensive Income.

If the company or any of its entities disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in net earnings.

(c) Revenues

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer and collection is reasonably assured. Revenue from properties in which the company has an interest with other producers is recognized on the basis of the company's net working interest. For operations not pursuant to production sharing contracts (PSCs), crude oil and natural gas sold below or above the company's working interest share of production results in production underlifts or overlifts, respectively. Underlifts are recorded as a receivable at market value with a corresponding increase to revenues, while overlifts are recorded as a payable at market value with a corresponding decrease to revenues. Revenue from oil and natural gas production is recorded net of royalty expense.

International operations conducted pursuant to PSCs are reflected in the consolidated financial statements based on the company's working interest. Each PSC establishes the exploration, development and operating costs the company is required to fund and establishes specific terms for the company to recover these costs (Cost Recovery Oil) and to share in the production profits (Profit Oil). Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the company and the respective government. Cost Recovery Oil and Profit Oil are reported as revenue when the sale of product to a third party occurs. Revenue also includes income taxes paid on the company's behalf by government joint venture partners.

(d) Cash and Cash Equivalents

Cash and cash equivalents consist primarily of cash in banks, term deposits, certificates of deposit and all other highly liquid investments at the time of purchase.

(e) Inventories

Inventories of crude oil and refined products, other than inventories held for trading purposes, are valued at the lower of cost, using the first-in, first-out method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location. Materials and supplies are valued at the lower of average cost and net realizable value.

Inventories held for trading purposes in the company's energy trading operations are carried at fair value less costs of disposal, and any changes in fair value are recognized within Other Income.

(f) Exploration and Evaluation Assets

The costs to acquire non-producing oil and gas properties or licences to explore, drill exploratory wells and the costs to evaluate the commercial potential of underlying resources, including related borrowing costs, are initially capitalized as Exploration and Evaluation assets. Certain exploration costs, including geological, geophysical, seismic, and delineation on oil sands properties, are charged to Exploration expense as incurred.

Exploration and Evaluation assets are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. If an area or exploration well is no longer considered commercially viable, the related capitalized costs are charged to Exploration expense.

When management determines with reasonable certainty that an Exploration and Evaluation asset will be developed, as evidenced by the classification of proved or probable reserves and the appropriate internal and external approvals, the asset is transferred to Property, Plant and Equipment.

(g) Property, Plant and Equipment

Property, Plant and Equipment are recorded at cost.

The costs to acquire developed or producing oil and gas properties, and to develop oil and gas properties, including completing geological and geophysical surveys and drilling development wells, and the costs to construct and install

development infrastructure, such as wellhead equipment, well platforms, well pairs, offshore platforms and subsea structures, are capitalized as oil and gas properties within Property, Plant and Equipment.

The costs to construct, install and commission, or acquire, oil and gas production equipment, including oil sands upgraders, extraction plants, mine equipment, processing and power generation facilities, utility plants, and all renewable energy, refining, and marketing assets, are capitalized as plant and equipment within Property, Plant and Equipment.

Stripping activity required to access oil sands mining resources incurred in the initial development phase is capitalized as part of the construction cost of the mine. Stripping costs incurred in the production phase are charged to expense as they normally relate to production for the current period.

The costs of planned major inspection, overhaul and turnaround activities that maintain Property, Plant and Equipment and benefit future years of operations are capitalized. Recurring planned maintenance activities performed on shorter intervals are expensed as operating costs. Replacements outside of a major inspection, overhaul or turnaround are capitalized when it is probable that future economic benefits will flow to the company and the associated carrying amount of the replaced asset (or part of a replaced asset) is derecognized.

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as finance lease assets within Property, Plant and Equipment. Costs for all other leases are recorded as operating expense as incurred.

Borrowing costs relating to assets that take a substantial period of time to construct are capitalized as part of the asset. Capitalization of borrowing costs ceases when the asset is in the location and condition necessary for its intended use, and is suspended when construction of an asset is ceased for extended periods.

(h) Depreciation, Depletion and Amortization

Exploration and Evaluation assets are not subject to depreciation, depletion and amortization. Once transferred to oil and gas properties within Property, Plant and Equipment and commercial production commences, these costs are depleted on a unit-of-production basis over proved developed reserves, with the exception of exploration and evaluation costs associated with oil sand mines, which are depreciated on a straight-line basis over the life of the mine, and property acquisition costs, which are depleted over proved reserves.

Capital expenditures are not depleted until assets are substantially complete and ready for their intended use.

Costs to develop oil and gas properties other than certain oil sands mining assets, including costs of dedicated infrastructure, such as well pads and wellhead equipment, are depleted on a unit-of-production basis over proved developed reserves. A portion of these costs may not be depleted if they relate to undeveloped reserves. Costs related to offshore facilities are depleted over proved and probable reserves. Costs to develop and construct oil sands mines are depreciated on a straight-line basis over the life of the mine.

Major components of Property, Plant and Equipment are depreciated on a straight-line basis over their expected useful lives.

Oil sands upgraders, extraction plants and mine facilities	20 to 40 years
Oil sands mine equipment	5 to 15 years
Oil sands in situ processing facilities	30 years
Power generation and utility plants	30 to 40 years
Refineries, ethanol and lubricants plants	20 to 40 years
Marketing and other distribution assets	20 to 40 years

The costs of major inspection, overhaul and turnaround activities that are capitalized are depreciated on a straight-line basis over the period to the next scheduled activity, which varies from two to five years.

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

(i) Goodwill and Other Intangible Assets

The company accounts for business combinations using the acquisition method. The excess of the purchase price over the fair value of the identifiable net assets represents goodwill, and is allocated to the cash generating units (CGUs) or groups of CGUs expected to benefit from the business combination.

Other intangible assets include acquired customer lists and brand value.

Goodwill and brand value have indefinite useful lives and are not subject to amortization. Customer lists are amortized over their expected useful lives, which range from five to ten years. Expected useful lives of goodwill and other intangible assets are reviewed on an annual basis.

(j) Impairment of Assets

Non-Financial Assets

Property, Plant and Equipment and Exploration and Evaluation assets are reviewed quarterly to assess whether there is any indication of impairment. Goodwill and intangible assets that have an indefinite useful life are tested for impairment annually. Exploration and Evaluation assets are also tested for impairment immediately prior to being transferred to Property, Plant and Equipment.

If any indication of impairment exists, an estimate of the asset's recoverable amount is calculated as the higher of the fair value less costs of disposal and value-in-use. In determining fair value less costs of disposal, recent market transactions are taken into account, if available. In the absence of such transactions, an appropriate valuation model is used. Value-in-use is assessed using the present value of the expected future cash flows of the relevant asset. If the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, the asset is tested as part of a CGU, which is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. An impairment loss is the amount by which the carrying amount of the individual asset or CGU exceeds its recoverable amount.

Impairments are reversed for all CGUs and individual assets, other than goodwill, if there has been a change in the estimates and judgments used to determine the asset's recoverable amount. If such indication exists, the carrying amount of the CGU or asset is increased to its revised recoverable amount which cannot exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, had no impairment been recognized.

Impairments and impairment reversals are recognized within Depreciation, Depletion, Amortization and Impairment.

Financial Assets

At each reporting date, the company assesses whether there is evidence that financial assets that are carried at amortized cost are impaired. If a financial asset carried at amortized cost is impaired, the impairment is recognized in Operating, Selling and General expense.

(k) Assets Held For Sale

Assets and liabilities are classified as held for sale if their carrying amounts are expected to be recovered through a disposition rather than through continuing use. The assets or disposal groups are measured at the lower of their carrying amount and fair value less costs of disposal. Impairment losses on initial classification as well as subsequent gains or losses on remeasurement are recognized in Depreciation, Depletion, Amortization and Impairment. However, when the assets or disposal groups are sold, the gains or losses on sale are recognized in (Gain) Loss on Disposal of Assets. Assets classified as held for sale are not depreciated, depleted or amortized.

(l) Provisions

Provisions are recognized by the company when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

Provisions are recognized for decommissioning and restoration obligations associated with the company's Exploration and Evaluation assets and Property, Plant and Equipment. Provisions for decommissioning and restoration obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, using the credit-adjusted risk-free interest rate. The value of the obligation is added to the carrying amount of the associated asset and amortized over the useful life of the asset. The provision is accreted over time through Financing Expenses with actual expenditures charged against the accumulated obligation. Changes in the future cash flow estimates

resulting from revisions to the estimated timing or amount of undiscounted cash flows are recognized as a change in the decommissioning and restoration provision and related asset.

(m) Income Taxes

The company follows the liability method of accounting for income taxes whereby deferred income taxes are recorded for the effect of differences between the accounting and income tax basis of an asset or liability. Deferred income tax assets and liabilities are measured using enacted or substantively enacted income tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are anticipated to be recovered or settled. Changes to these balances are recognized in net earnings or in Other Comprehensive Income in the period they occur. Investment tax credits are recorded as an offset to the related expenditures.

The company recognizes the financial statement impact of a tax filing position when it is probable, based on the technical merits, that the position will be sustained upon audit. The company assesses possible outcomes and their associated probabilities. If the company determines payment is probable, it measures the tax position at the best estimate of the amount of tax payable.

(n) Pensions and Other Post-Retirement Benefits

The company sponsors defined benefit pension plans, defined contribution pension plans and other post-retirement benefits.

The cost of pension benefits earned by employees in the defined contribution pension plan is expensed as incurred. The cost of defined benefit pension plans and other post-retirement benefits are actuarially determined using the projected unit credit method based on present pay levels and management's best estimates of demographic and financial assumptions. Pension benefits earned during the current year are recorded in Operating, Selling and General expense. Interest costs on the net unfunded obligation are recorded in Financing Expenses. Any actuarial gains or losses are recognized immediately through Other Comprehensive Income and transferred directly to Retained Earnings.

The liability recognized on the balance sheet is the present value of the defined benefit obligations less the fair value of plan assets.

(o) Share-Based Compensation Plans

Under the company's share-based compensation plans, share-based awards may be granted to executives, employees and non-employee directors. Compensation expense is recorded in Operating, Selling and General expense.

Share-based compensation awards that settle in cash or have the option to settle in cash or shares are accounted for as cash-settled plans. These are measured at fair value each reporting period using the Black-Scholes options pricing model, with the exception of performance share units, which are measured at fair value using the Monte-Carlo simulation approach. The expense is recognized over the vesting period, with a corresponding adjustment to liabilities. When awards are surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the options are recorded to Share Capital.

Stock options that give the holder the right to purchase common shares are accounted for as equity-settled plans. The expense is based on the fair value of the options at the time of grant using the Black-Scholes options pricing model and is recognized over the vesting periods of the respective options. A corresponding increase is recorded to Contributed Surplus. Consideration paid to the company on exercise of options is credited to Share Capital and the associated amount in Contributed Surplus is reclassified to Share Capital.

(p) Financial Instruments

The company classifies its financial instruments into one of the following categories: fair value through profit or loss; assets available for sale; held-to-maturity investments; loans and receivables, and financial liabilities measured at amortized cost. All financial instruments are initially recognized at fair value on the balance sheet, net of any transaction costs except for financial instruments classified as fair value through profit and loss, where transaction costs are expensed as incurred. Subsequent measurement of financial instruments is based on their classification. The company classifies derivative financial instruments as fair value through profit and loss, cash and cash equivalents and accounts receivable as loans and receivables, financial instruments included in other assets as available for sale, and accounts payable and accrued liabilities, debt, and other long-term liabilities as other financial liabilities.

The company uses derivative financial instruments, such as physical and financial contracts, either to manage certain exposures to fluctuations in interest rates, commodity prices and foreign exchange rates, as part of its overall risk management program, or to earn trading revenues. Earnings impacts from derivatives used to manage a particular risk are reported as part of Other Income in the related operating segment. Gains or losses from trading activities are reported in Other Income as part of Corporate, Energy Trading and Eliminations.

Certain physical commodity contracts are deemed to be derivative financial instruments for accounting purposes. Physical commodity contracts entered into for the purpose of receipt or delivery in accordance with the company's expected purchase, sale or usage requirements are not considered to be derivative financial instruments.

Derivatives embedded in other financial instruments or other host contracts are recorded as separate derivatives when their risks and characteristics are not closely related to those of the host contract.

(q) Hedging Activities

The company may apply hedge accounting to arrangements that qualify for designated hedge accounting treatment. Documentation is prepared at the inception of a hedge relationship in order to qualify for hedge accounting. Designated hedges are assessed at each reporting date to determine if the relationship between the derivative and the underlying hedged exposure is still effective and to quantify any ineffectiveness in the relationship.

If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and in the fair value of the hedged item attributable to the hedged risk are recognized in net earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in Other Comprehensive Income and are recognized in net earnings when the hedged item is realized. Ineffective portions of changes in the fair value of cash flow hedges are recognized in net earnings immediately. Changes in the fair value of a derivative designated in a fair value or cash flow hedge are recognized in the same line item as the underlying hedged item.

(r) Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects. When the company repurchases its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value is recognized as a deduction from Retained Earnings. Shares are cancelled upon repurchase.

(s) Dividend Distributions

Dividends on common shares are recognized in the period in which the dividends are declared by the company's Board of Directors.

(t) Earnings per Share

Basic earnings per share is calculated by dividing the net earnings for the period by the weighted average number of common shares outstanding during the period.

Diluted earnings per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive common shares related to the company's share-based compensation plans. The number of shares included is computed using the treasury stock method. Options with tandem stock appreciation rights or cash payment alternatives are accounted for as cash-settled plans. As these awards can be exchanged for common shares of the company, they are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share if they have a dilutive impact in the period.

(u) Emissions Obligations

Emissions obligations are measured at the weighted average cost per unit of emissions expected to be incurred in the compliance period. Emissions are treated as a cost of production and as such are recognized in Operating, Selling and General expenses in the period in which the emissions occurred.

Purchases of emissions rights are recognized as Other Assets on the balance sheet and are measured at historical cost. Emissions rights received by way of grant are recorded at a nominal amount.

(v) Joint Arrangements

The classification of joint arrangements structured through separate vehicles as either joint ventures or joint operations depends on the legal form and contractual terms of the arrangement as well as other facts and circumstances. These include whether there is exclusive dependence on the parties to the joint arrangement for cash flows through the sale of product and funding of operations, and to assess the rights of the economic benefits of the assets and obligation for funding the liabilities of the arrangements.

A joint arrangement whereby the parties take their share of substantially all of the output of the joint arrangement would be an indicator for classification as a joint operation, regardless of structure of the arrangement, and accounted for by recognizing the company's share of assets and liabilities jointly owned and incurred, and the recognition of its share of revenue and expenses of the joint operation.

4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of financial statements in accordance with IFRS requires management to make estimates and judgments that affect reported assets, liabilities, revenues, expenses, gains, losses, and disclosures of contingencies. These estimates and judgments are subject to change based on experience and new information. The financial statement areas that require significant estimates and judgments are as follows:

Oil and Gas Reserves and Resources

Measurements of depletion, depreciation, impairment and decommissioning and restoration obligations are determined in part based on the company's estimate of oil and gas reserves and resources. The estimation of reserves and resources is an inherently complex process and involves the exercise of professional judgment. All reserves and certain resources have been evaluated at December 31, 2014 by independent qualified reserves evaluators. Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Estimates reflect market and regulatory conditions existing at December 31, 2014, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Oil and Gas Activities

The company is required to apply judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the initial costs of these activities are capitalized.

Exploration and Evaluation Costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The company is required to make judgments about future events and circumstances and applies estimates to assess the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop the project. Level of drilling success or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures are important judgments when making this determination. Management uses judgment to determine when these costs are reclassified to Property, Plant and Equipment based on several factors including the existence of reserves, appropriate approvals from regulatory bodies and the company's internal project approval process.

Determination of Cash Generating Units

A CGU is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations.

Asset Impairment and Reversals

Management applies judgment in assessing the existence of impairment and impairment reversal indicators based on various internal and external factors.

The recoverable amount of CGUs and individual assets is determined based on the higher of fair value less costs of disposal or value-in-use calculations. The key estimates the company applies in determining the recoverable amount normally include estimated future commodity prices, expected production volumes, future operating and development costs, discount rates, tax rates, and refining margins. In determining the recoverable amount, management may also be required to make judgments regarding the likelihood of occurrence of a future event. Changes to these estimates and judgments will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value.

Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of Exploration and Evaluation assets and Property, Plant and Equipment. Management applies judgment in assessing the existence and extent as well as the expected method of reclamation of the company's decommissioning and restoration obligations at the end of each reporting period. Management also uses judgment to determine whether the nature of the activities performed is related to decommissioning and restoration activities or normal operating activities.

In addition, these provisions are based on estimated costs, which take into account the anticipated method and extent of restoration, technological advances, possible future use of the site, and reclamation projects and processes such as the Tailings Reduction Operations process and the water treatment facility. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience, prices and closure plans. The estimated timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to estimates related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

Employee Future Benefits

The company provides benefits to employees, including pensions and other post-retirement benefits. The cost of defined benefit pension plans and other post-retirement benefits received by employees is estimated based on actuarial valuation methods that require professional judgment. Estimates typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, the return on plan assets, mortality rates and future medical costs. Changes to these estimates may have a material impact on the amounts presented.

Other Provisions

The determination of other provisions, including, but not limited to, provisions for royalty disputes, onerous contracts, litigation and constructive obligations, is a complex process that involves judgments about the outcomes of future events, the interpretation of laws and regulations, and estimates on timing and amount of expected future cash flows and discount rates.

Income Taxes

Management evaluates tax positions, annually or when circumstances require, which involves judgment and could be subject to differing interpretations of applicable tax legislation. The company recognizes a tax provision when a payment to tax authorities is considered probable. However, the results of audits and reassessments and changes in the interpretations of standards may result in changes to those positions and potentially a material increase or decrease in the company's assets, liabilities and net earnings.

Deferred Income Taxes

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's judgment of the likelihood of a future outflow and estimates of the expected settlement amount, timing of reversals, and the tax laws in the jurisdictions in which the company operates.

Fair Value of Financial Instruments

The fair value of financial instruments is determined whenever possible based on observable market data. If not available, the company uses third-party models and valuation methodologies that utilize observable market data including forward commodity prices, foreign exchange rates and interest rates to estimate the fair value of financial instruments, including derivatives. In addition to market information, the company incorporates transaction-specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk.

Functional Currency

The designation of the company's functional currency is a management judgment based on the composition of revenue and costs in the locations in which it operates.

Fair Value of Share-Based Compensation

The fair values of equity-settled and cash-settled share-based payment awards are estimated using the Black-Scholes options pricing model and Monte-Carlo simulation approach. These estimates depend on certain assumptions, including share price, volatility, risk-free interest rate, the term of the awards, the forfeiture rate and the annual dividend yield, which, by their nature, are subject to measurement uncertainty.

5. RECENTLY ANNOUNCED ACCOUNTING PRONOUNCEMENTS

The standards and interpretations that are issued, but not yet effective up to the date of issuance of the company's consolidated financial statements, and that may have an impact on the disclosures and financial position of the company, are disclosed below. The company intends to adopt these standards and interpretations, if applicable, when they become effective.

Accounting for Acquisitions of Interests in Joint Operations

In May 2014, the IASB issued amendments to IFRS 11 *Joint Arrangements* to clarify that the acquirer of an interest in a joint operation in which the activity constitutes a business is required to apply all of the principles of business combinations accounting in IFRS 3 *Business Combinations*. Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the company in the event it increases or decreases its ownership share in an existing joint operation or invests in a new joint operation.

Sale or Contribution of Assets between an Investor and its Associate or Joint Venture

In September 2014, the IASB issued amendments to address an inconsistency between the requirements in IFRS 10 *Consolidated Financial Statements* and those in International Accounting Standard (IAS) 28 *Investments in Associates and Joint Ventures* regarding the sale or contribution of assets between an investor and its associate or joint venture. The amendment clarified that a full gain or loss is recognized when a transaction involves a business. A partial gain or loss is recognized when a transaction involves assets that do not constitute a business. Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the company in the event that it has transactions with Associates or Joint Ventures.

Disclosure Initiative

In December 2014, the IASB issued narrow-focus amendments to IAS 1 *Presentation of Financial Statements* to clarify existing requirements related to materiality, order of notes, subtotals, accounting policies and disaggregation. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amended standard is not expected to have a material impact on the company's disclosure.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers.* It replaces existing revenue recognition guidance and provides a single, principles based five-step model to be applied to all contracts with customers. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2017, with earlier application permitted. The company is currently assessing the impact of this standard.

Financial Instruments: Recognition and Measurement

In July 2014, IFRS 9 *Financial Instruments* was issued as a complete standard, including the requirements previously issued related to classification and measurement of financial assets and liabilities, and additional amendments to introduce a new expected loss impairment model for financial assets including credit losses. Retrospective application of this standard with certain exemptions is effective for fiscal years beginning on or after January 1, 2018, with earlier application permitted. The company is currently assessing the impact of this standard.

6. ADOPTION OF NEW AND AMENDED IFRS STANDARDS

Effective January 1, 2014, the company adopted the following new and amended IFRS standards and interpretations.

Offsetting Financial Assets and Financial Liabilities

IAS 32 *Financial Instruments: Presentation* amendments clarified the requirements for offsetting financial assets and liabilities. The amendments clarified that the right to offset must be available on the current date and cannot be contingent on a future event. The adoption of this standard did not have a material impact on the company's consolidated financial statements.

Levies

International Financial Reporting Interpretation Committee (IFRIC) 21 *Levies* clarified that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that a levy liability is accrued progressively only if the activity that triggers payment occurs over a period of time, and that a liability should not be recognized before the specified minimum threshold to trigger that liability is reached. This interpretation did not have a material impact to the company's consolidated financial statements.

7. SEGMENTED INFORMATION

The company's operating segments are reported based on the nature of their products and services and management responsibility. The following summary describes the operations in each of the segments:

- Oil Sands includes the company's operations in northeast Alberta to develop and produce synthetic crude oil and related products, through the recovery and upgrading of bitumen from mining and in situ operations. This segment also includes the company's joint interest in the Fort Hills mining project of 40.8% as well as its 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, located near Fort McMurray, Alberta.

- Exploration and Production includes offshore activity in East Coast Canada, with interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, the exploration and production of crude oil and natural gas in the United Kingdom (U.K.), Norway, Libya and Syria, and exploration and production of natural gas and natural gas liquids in Western Canada. Due to unrest in Syria, the company has declared force majeure under its contractual obligations, and Suncor's operations in Syria have been suspended indefinitely.

- Refining and Marketing includes the refining of crude oil products, and the distribution and marketing of these and other purchased products through retail stations located in Canada and the United States (U.S.), as well as a lubricants plant located in Eastern Canada.

The company also reports activities not directly attributable to an operating segment under Corporate, Energy Trading and Eliminations. This includes investments in renewable energy projects.

Intersegment sales of crude oil and natural gas are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer. Intersegment

balances are eliminated on consolidation. Intersegment profit will not be recognized until the related product has been sold to third parties.

For the years ended December 31 ($ millions)	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
	2014	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Revenues and Other Income										
Gross revenues	**10 658**	9 063	**4 290**	5 931	**26 482**	26 495	**86**	109	**41 516**	41 598
Intersegment revenues	**3 903**	4 026	**425**	432	**145**	163	**(4 473)**	(4 621)	**—**	—
Less: Royalties	**(982)**	(859)	**(672)**	(1 146)	**—**	—	**—**	—	**(1 654)**	(2 005)
Operating revenues, net of royalties	**13 579**	12 230	**4 043**	5 217	**26 627**	26 658	**(4 387)**	(4 512)	**39 862**	39 593
Other income	**115**	64	**217**	381	**151**	22	**145**	237	**628**	704
	13 694	12 294	**4 260**	5 598	**26 778**	26 680	**(4 242)**	(4 275)	**40 490**	40 297
Expenses										
Purchases of crude oil and products	**355**	460	**459**	568	**21 093**	20 807	**(4 481)**	(4 542)	**17 426**	17 293
Operating, selling and general	**6 042**	5 852	**558**	676	**2 447**	2 307	**702**	627	**9 749**	9 462
Transportation	**541**	482	**90**	127	**290**	278	**(42)**	(42)	**879**	845
Depreciation, depletion, amortization and impairment	**4 035**	2 439	**1 349**	1 804	**635**	530	**121**	119	**6 140**	4 892
Exploration	**96**	115	**271**	207	**—**	—	**—**	—	**367**	322
Loss (gain) on disposal of assets	**3**	—	**(82)**	(130)	**(11)**	(7)	**—**	—	**(90)**	(137)
Voyageur upgrader project charges	**—**	82	**—**	—	**—**	—	**—**	—	**—**	82
Financing expenses	**153**	135	**72**	33	**—**	5	**1 204**	989	**1 429**	1 162
	11 225	9 565	**2 717**	3 285	**24 454**	23 920	**(2 496)**	(2 849)	**35 900**	33 921
Earnings (Loss) before Income Taxes	**2 469**	2 729	**1 543**	2 313	**2 324**	2 760	**(1 746)**	(1 426)	**4 590**	6 376
Income Taxes										
Current	**832**	331	**1 005**	1 443	**675**	674	**(397)**	(365)	**2 115**	2 083
Deferred	**(139)**	358	**(115)**	(130)	**(43)**	64	**73**	90	**(224)**	382
	693	689	**890**	1 313	**632**	738	**(324)**	(275)	**1 891**	2 465
Net Earnings (Loss)	**1 776**	2 040	**653**	1 000	**1 692**	2 022	**(1 422)**	(1 151)	**2 699**	3 911
Capital and Exploration Expenditures	**3 826**	4 311	**1 819**	1 483	**1 021**	890	**295**	93	**6 961**	6 777

Geographical Information

Operating Revenues, net of Royalties

($ millions)	**2014**	2013
Canada	**31 894**	31 407
United States	**5 651**	5 415

Other foreign	**2 317**	2 771
	39 862	39 593

Non-Current Assets[1]

($ millions)	Dec 31 2014	Dec 31 2013
Canada	**59 409**	57 235
United States	**1 495**	1 330
Other foreign	**4 825**	4 991
	65 729	63 556

(1) Excludes deferred income tax assets.

8. OTHER INCOME

Other Income consists of the following:

($ millions)	2014	2013
Energy trading activities		
Change in fair value of contracts	**173**	176
(Losses) gains on inventory valuation	**(61)**	15
Risk management activities[1]	**176**	(18)
Risk mitigation and insurance proceeds	**21**	342
Reserves redetermination[2]	**145**	—
Investment and interest income	**90**	85
Renewable energy grants	**34**	47
Change in value of pipeline commitments and other	**50**	57
	628	704

(1) Includes fair value changes related to short-term derivative contracts in the Oil Sands and Refining and Marketing segments.

(2) Other income of $145 million ($32 million after-tax) is for the reserves redetermination of 1.2 million barrels of oil received related to an interest in a Norwegian asset that Suncor previously owned.

9. OPERATING, SELLING AND GENERAL

Operating, Selling and General expense consists of the following:

($ millions)	2014	2013
Contract services	**3 842**	4 412
Employee costs[1]	**2 891**	2 654
Materials	**1 093**	932
Energy	**1 180**	915
Equipment rentals and leases	**299**	335
Travel, marketing and other	**444**	214
	9 749	9 462

(1) The company incurred $3.4 billion of employee costs for the year ended December 31, 2014 (2013 – $3.3 billion), of which $2.9 billion (2013 – $2.7 billion) was recorded as

employee costs in Operating, Selling and General expense. Employee costs include salaries, benefits and share-based compensation.

10. ASSET IMPAIRMENT

Oil Sands

Joslyn Mining Project

During the second quarter of 2014, the company recognized an impairment charge of $718 million (net of taxes of $248 million) related to the company's interest in the Joslyn mining project, charged against Property, Plant and Equipment ($318 million) and Exploration and Evaluation assets ($400 million).

Total E&P Canada Ltd. (Total E&P), the operator of the project, together with the company and the other co-owners of the project, agreed to scale back certain development activities in order to focus on engineering studies to further optimize the project development plan. As a result of the company's assessment of expected future net cash flows and the uncertainty of the project, including the timing of the development plans, the company performed an impairment test using a fair value less cost of disposal methodology, with a discounted cash flow approach, based on the latest estimate of lease-wide contingent resources and a risk-adjusted discount rate of 9% (Level 3 fair value inputs – see note 27). Relevant market transactions were also considered.

The company re-assessed the Joslyn mining project and noted no impairment indicators as at December 31, 2014, due to the long-term nature of the project.

The calculation of the recoverable amount as at June 30, 2014 was sensitive to the likelihood and timing of expected first oil, discount rate and capital construction costs. A two-year delay in the timing of expected first oil would increase the after-tax impairment charge by approximately $50 million. A 1% increase in discount rate would increase the after-tax impairment charge by approximately $360 million. A 5% increase in capital construction costs would increase the after-tax impairment charge by approximately $190 million.

The remaining carrying value of the company's share of the Joslyn mining project as at December 31, 2014 was $400 million.

Other

In the second quarter of 2014, the company recorded an impairment charges of $223 million (net of taxes of $77 million) in the Oil Sands segment following a review of certain assets that no longer fit with Suncor's previously revised growth strategies and which could not be repurposed or otherwise deployed. Such assets included a pipeline and related compressor, as well as steam generator components.

Exploration and Production

Libya

During the second quarter of 2014, as a result of production shut-in due to the closure of certain Libyan export terminals and the company's production plans for the remaining term of the Exploration and Production Sharing Agreements (EPSAs), the company performed an impairment test on its Libyan assets using a fair value less cost of disposal methodology. This resulted in the company recognizing an impairment charge of $297 million (net of taxes of $nil) related to its Libyan assets, charged against Property, Plant and Equipment ($129 million) and Exploration and Evaluation assets ($168 million).

As a result of the current price environment and recent developments in the country, the Libyan assets were reassessed for impairment at December 31, 2014. The impairment test used an expected cash flow approach based on 2014 year-end reserves data and the company's production and cash flow expectations for the remaining term of the EPSAs, with two scenarios representing i) full production resumes on January 1, 2016, and ii) full production resumes on April 1, 2017. The two scenarios were equally weighted at 50%. Both scenarios were present valued using a risk-adjusted discount rate of 17%, and a Brent-based price of US$82.50 per barrel in 2016, US$87.50 in 2017, US$90.00 in 2018, US$95.00 in 2019, US$100.00 in 2020, US$101.35 in 2021, and then escalating at an average of 2% per year thereafter (Level 3 fair value inputs). Based on the updated analysis, no further impairment was necessary.

The calculation of the recoverable amount is sensitive to the discount rate and prices. A 2% increase in discount rate would result in an after-tax impairment charge of approximately $60 million and a 5% decrease in price would result in an after-tax impairment charge of approximately $70 million. A delay in the timing of the expected return to full production to April 1, 2017 would result in an after-tax impairment charge of approximately $35 million at December 31, 2014.

During 2013, the company performed an impairment test on its Libyan assets using a fair value less cost of disposal methodology to determine the recoverable amount, and an after-tax impairment charge of $101 million was recognized in the fourth quarter of 2013 and charged against Property, Plant and Equipment.

The remaining carrying value of the company's net assets in Libya as at December 31, 2014 was approximately $375 million.

Syria

Since December 2011, the company's operations and its contractual obligations in Syria have been suspended under a period of force majeure due to political unrest and international sanctions affecting that country. As there has been no resolution of the political situation and increasing uncertainty with respect to the company's return to operations in the country, during the fourth quarter of 2013, using a value-in-use methodology, the company impaired the remaining carrying value of its Syrian property, plant and equipment and working capital, resulting in an impairment charge of $422 million (net of taxes of $nil). The company also recognized $300 million ($223 million after-tax) of risk mitigation proceeds in Other Income that had been received in the fourth quarter of 2012 as the likelihood of return in the foreseeable future is remote. These proceeds are subject to a provisional repayment should the company recover any or all of its investment in Syria.

The remaining carrying value of the company's net assets in Syria as at December 31, 2014 was $nil.

Other

In the fourth quarter of 2013, the company recognized an impairment charge in the E&P segment of $40 million (net of taxes of $14 million) to reflect the recoverable amount of its unconventional oil properties in the Wilson Creek area of central Alberta. The recoverable amount was determined using a fair value less costs of disposal methodology, with the expected cash flow approach based on 2013 year-end reserves information and a risk-adjusted discount rate of 10% (Level 3 fair value inputs). The Wilson Creek assets were sold in 2014 (note 35).

11. FINANCING EXPENSES

($ millions)	2014	2013
Interest on debt and finance leases	**739**	703
Capitalized interest at 6.2% (2013 – 6.1%)	**(431)**	(397)
Interest expense	**308**	306
Interest on pension and other post-retirement benefits	**55**	68
Accretion	**198**	192
Foreign exchange loss on U.S. dollar denominated debt	**839**	605
Foreign exchange and other	**29**	(9)
	1 429	1 162

12. INCOME TAXES

Income Tax Expense

($ millions)	2014	2013
Current:		
Current year	**2 017**	2 093
Adjustments in respect of current income tax of prior years	**98**	(10)
Deferred:		
Origination and reversal of temporary differences	**(143)**	410
Adjustments in respect of deferred income tax of prior years	**(52)**	(28)
Changes in tax rates and legislation	**(29)**	—
	1 891	2 465

Reconciliation of Effective Tax Rate

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the difference is as follows:

($ millions)	**2014**	2013
Earnings before income tax	**4 590**	6 376
Canadian statutory tax rate	**25.66%**	25.64%
Statutory tax	**1 178**	1 635
Add (deduct) the tax effect of:		
Non-deductible component of capital losses	**98**	71
Share-based compensation and other permanent items	**27**	5
Assessments and adjustments	**46**	(38)
Impact of income tax rate and legislative changes	**(29)**	—
Foreign tax rate differential	**483**	691
Non-taxable impairment charge	**76**	134
Other	**12**	(33)
	1 891	2 465

Deferred Income Tax Balances

Deferred income tax expense and net liabilities in the company's consolidated financial statements were comprised of the following:

	Net Earnings		Consolidated Balance Sheets [1]	
($ millions)	**2014**	2013	Dec 31 2014	Dec 31 2013
Property, plant and equipment	**(98)**	758	**12 349**	12 134
Decommissioning and restoration provision	**107**	(54)	**(1 207)**	(1 017)
Employee retirement benefit plans	**34**	(103)	**(563)**	(541)
Tax loss carry-forwards	**(10)**	136	**(41)**	(31)
Partnership deferral reserve	**(58)**	(213)	**134**	192
Foreign exchange and other	**(199)**	(142)	**(155)**	(18)
	(224)	382	**10 517**	10 719

(1) The current and non-current portion of the deferred income tax liability and asset are as follows:

($ millions)	**Dec 31 2014**	Dec 31 2013
Current deferred income tax liability	**333**	103
Current deferred income tax asset	**—**	(4)
Non-current deferred income tax liability	**10 210**	10 681
Non-current deferred income tax asset	**(26)**	(61)
Net deferred income tax liability	**10 517**	10 719

Change in Deferred Income Tax Balances

($ millions)	2014	2013
Beginning of year	**10 719**	10 366
Recognized in deferred income tax expense	**(224)**	382
Recognized in other comprehensive income	**(43)**	201
Foreign exchange, disposition and other	**65**	(230)
End of year	**10 517**	10 719

Deferred Tax in Other Comprehensive Income (Loss)

	Twelve months ended December 31	
($ millions)	2014	2013
Unrealized gain on assets available for sale	**(13)**	—
Actuarial gain (loss) on employee retirement benefit plans	**56**	(201)
	43	(201)

No deferred tax liability has been recognized at December 31, 2014 on temporary differences of approximately $11.3 billion (2013 – $11.2 billion) associated with earnings retained in our investments in foreign subsidiaries, as the company is able to control the timing of the reversal of these differences. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense. Deferred distribution taxes associated with international business operations have not been recorded.

Canada Revenue Agency Update

Pursuant to the previously disclosed 2013 proposal letter from the Canada Revenue Agency (CRA), in 2014, the company received a Notice of Reassessment (NOR) from the CRA regarding the income tax treatment of realized losses in 2007 on the settlement of certain derivative contracts. The total amount of the NOR including tax, penalty and interest was approximately $920 million. Also during the year:

- The company received NORs related to the derivative contracts from Quebec and Ontario for approximately $42 million and $100 million, respectively. The Alberta NOR (approximately $124 million) was received in the first quarter of 2015.
- The company provided security to the CRA and the Provinces of Quebec and Ontario for approximately $610 million.
- The company filed Notices of Objection with CRA and the Provinces of Quebec and Ontario.
- The company filed a Notice of Appeal with the Tax Court of Canada.

If the company is unsuccessful in defending its tax filing position, it could be subject to an earnings and cash impact of up to $1.2 billion.

13. EARNINGS PER COMMON SHARE

($ millions)	2014	2013
Net earnings	**2 699**	3 911
(millions of common shares)		
Weighted average number of common shares	**1 462**	1 501
Dilutive securities:		
Effect of share options	**3**	1
Weighted average number of diluted common shares	**1 465**	1 502
(dollars per common share)		
Basic earnings per share	**1.84**	2.61
Diluted earnings per share	**1.84**	2.60

14. CASH AND CASH EQUIVALENTS

($ millions)	Dec 31 2014	Dec 31 2013
Cash	**659**	1 184
Cash equivalents	**4 836**	4 018
	5 495	5 202

15. SUPPLEMENTAL CASH FLOW INFORMATION

The (increase) decrease in non-cash working capital is comprised of:

($ millions)	2014	2013
Accounts receivable	**1 108**	(60)
Inventories	**444**	(220)
Accounts payable and accrued liabilities	**(784)**	69
Current portion of provisions	**(240)**	206
Income taxes payable (net)	**(591)**	603
	(63)	598
Relating to:		
Operating activities	**(122)**	688
Investing activities	**59**	(90)

16. INVENTORIES

($ millions)	**Dec 31 2014**	Dec 31 2013
Crude oil	**1 081**	1 269
Refined products	**1 474**	1 695
Materials, supplies and merchandise	**623**	594
Energy trading commodity inventories	**288**	386
	3 466	3 944

During 2014, product inventories of $18.0 billion (2013 – $18.0 billion) were expensed. There was a write-down of inventories of $11 million in 2014 (2013 – nil). Energy trading commodity inventories are measured at fair value less costs of disposal based on Level 1 and Level 2 fair value inputs.

17. PROPERTY, PLANT AND EQUIPMENT

($ millions)	Oil and Gas Properties	Plant and Equipment	Total
Cost			
At December 31, 2012	24 454	49 914	74 368
Additions	2 094	4 475	6 569
Transfers from exploration and evaluation	644	—	644
Acquisitions (note 33)	—	374	374
Changes in decommissioning and restoration	358	18	376
Disposals and derecognition	(2 578)	(921)	(3 499)
Foreign exchange adjustments	551	166	717
At December 31, 2013	25 523	54 026	79 549
Additions	**2 626**	**4 015**	**6 641**
Acquisitions (note 34)	**—**	**161**	**161**
Changes in decommissioning and restoration	**1 027**	**38**	**1 065**
Disposals and derecognition	**(253)**	**(2 882)**	**(3 135)**
Foreign exchange adjustments	**312**	**229**	**541**
At December 31, 2014	**29 235**	**55 587**	**84 822**
Accumulated provision			
At December 31, 2012	(6 493)	(12 441)	(18 934)
Depreciation and depletion	(2 056)	(2 181)	(4 237)
Impairment (note 10)	(155)	(444)	(599)
Disposals and derecognition	997	744	1 741
Foreign exchange adjustments	(189)	(61)	(250)
At December 31, 2013	(7 896)	(14 383)	(22 279)

Depreciation and depletion	**(1 847)**	**(2 708)**	**(4 555)**
Impairment (note 10)	**(129)**	**(428)**	**(557)**
Disposals and derecognition	**136**	**2 560**	**2 696**
Foreign exchange adjustments	**(201)**	**(126)**	**(327)**
At December 31, 2014	**(9 937)**	**(15 085)**	**(25 022)**

Net property, plant and equipment			
December 31, 2013	17 627	39 643	57 270
December 31, 2014	**19 298**	**40 502**	**59 800**

($ millions)	Dec 31, 2014 Cost	Dec 31, 2014 Accumulated provision	Dec 31, 2014 Net book value	Dec 31, 2013 Cost	Dec 31, 2013 Accumulated provision	Dec 31, 2013 Net book value
Oil Sands	**54 011**	**(13 032)**	**40 979**	52 127	(12 125)	40 002
Exploration and Production	**17 667**	**(8 021)**	**9 646**	15 660	(6 704)	8 956
Refining and Marketing	**11 545**	**(3 279)**	**8 266**	10 449	(2 883)	7 566
Corporate, Energy Trading and Eliminations	**1 599**	**(690)**	**909**	1 313	(567)	746
	84 822	**(25 022)**	**59 800**	79 549	(22 279)	57 270

At December 31, 2014, the balance of assets under construction and not subject to depreciation or depletion was $12.3 billion (December 31, 2013 – $11.1 billion).

At December 31, 2014, Property, Plant and Equipment included finance leases with a net book value of $949 million (December 31, 2013 – $997 million).

Fort Hills Project

On October 30, 2013, the co-owners of Fort Hills announced project sanction. As a result, the accumulated capital costs in Exploration and Evaluation assets were transferred to oil and gas properties in Property, Plant and Equipment and an impairment test was required in accordance with IFRS 6 *Exploration for and Evaluation of Mineral Resources* . A fair value less cost of disposal methodology was used to determine the recoverable amount and, as it exceeded the carrying amount, no impairment was recorded.

The company reassessed Fort Hills for impairment at December 31, 2014 and noted no impairment. A fair value less cost of disposal methodology was used. Key assumptions used in the calculation of the recoverable amount were discount rate, bitumen price and future capital costs. For purposes of calculating the recoverable amount, the company applied a risk-adjusted discount rate of 8%, assumed bitumen price of $53.28 per barrel at first oil in 2017, $66.58 per barrel in 2018, escalating at an average of 2% per year thereafter, for the remaining life of the mine, and go forward capital costs of $4.2 billion (Level 3 fair value inputs).

The assumptions used by management to calculate the recoverable amount may change. Changes in these assumptions will have an impact on the recoverable amount and may result in impairment. A 1% increase in discount rate would have resulted in a decrease to the recoverable amount of $1.2 billion. Bitumen prices were based on third-party published price curves adjusted for the company's view on long-term pricing economics and marketing information. A 5% decrease in prices would have resulted in a decrease to the recoverable amount of $915 million. Future capital costs of the mine are derived from company experience and adjusted for specific attributes of the project and expected cost savings due to new technologies. A 15% increase to this estimate (over the construction period) would have resulted in a decrease to the recoverable amount of $625 million.

18. EXPLORATION AND EVALUATION ASSETS

($ millions)	2014	2013
Beginning of year	**2 772**	3 284
Additions	**292**	225
Transfers to oil and gas assets	**—**	(644)
Dry hole expenses	**(104)**	(82)
Disposals	**—**	(11)
Impairment (Note 10)	**(706)**	—
Amortization	**(7)**	(13)
Foreign exchange adjustments	**1**	13
End of year	**2 248**	2 772

19. OTHER ASSETS

($ millions)	Dec 31 2014	Dec 31 2013
Investments (note 36)	**447**	325
Prepaids and other	**151**	97
	598	422

20. GOODWILL AND OTHER INTANGIBLE ASSETS

	Oil Sands	Refining and Marketing			
($ millions)	Goodwill	Goodwill	Brand name	Customer lists	Total
At December 31, 2012	2 752	148	166	38	3 104
Amortization	—	—	—	(12)	(12)
At December 31, 2013	2 752	148	166	26	3 092
Amortization	**—**	**—**	**—**	**(9)**	**(9)**
At December 31, 2014	**2 752**	**148**	**166**	**17**	**3 083**

The company performed its most recent goodwill impairment test at October 31, 2014 (and, as a result of the current price environment, updated the test with December 31, 2014 pricing). Recoverable amounts for the Oil Sands CGUs were based on fair value less costs of disposal calculated using the present value of the CGUs' expected future cash flows. The primary sources of cash flow information are derived from business plans approved by executives of the company, which were developed based on macroeconomic factors such as forward price curves for benchmark commodities, inflation rates and industry supply-demand fundamentals. When required, the projected cash flows in the business plans have been updated to reflect current market assessments of key assumptions, including long-term forecasts of commodity prices, inflation rates, foreign exchange rates and discount rates specific to the asset (Level 3 fair value inputs).

Cash flow forecasts are also based on past experience, historical trends and third-party evaluations of the company's reserves and resources to determine production profiles and volumes, operating costs, maintenance and capital expenditures. Production profiles, reserves volumes, operating costs, maintenance and capital expenditures are consistent with the estimates approved through the company's annual reserves evaluation process and determine the duration of the underlying cash flows used in the discounted cash flow test.

Future cash flow estimates are discounted using after-tax risk-adjusted discount rates. The discount rates are calculated based on the weighted average cost of capital that is implicit in current market transactions for similar assets. The after-tax discount rate applied to cash flow projections was 10% at October 31, 2014 (October 31, 2013 – 10%). The company based its cash flow projections on a December 31, 2014 average West Texas Intermediate (WTI) price of US$62.50 per barrel in 2015, US$75.00 per barrel in 2016, US$80.00 per barrel in 2017, and then escalating at an average of 6% per year from 2018 – 2020 and at an average of 2% thereafter, adjusted for applicable quality and location differentials depending on the underlying CGU. The forecasted cash flow period ranged from 20 years to 50 years based on the reserve life of the respective CGU. As a result of this analysis, management did not identify impairment within the Oil Sands operating segment and the associated allocated goodwill.

The company also performed a goodwill impairment test at October 31, 2014 of its Refining and Marketing CGUs. The recoverable amounts were based on the fair value less costs of disposal calculated using the present value of the CGUs' expected future cash flows, based primarily on the business plan and historical results adjusted for current economic conditions, and escalated using an inflation rate of 2% of revenue and operating costs. The after-tax discount rate applied to the cash flow projection was between 10% and 15% at October 31, 2014 (October 31, 2013 – between 10% and 15%). As a result of this analysis, no impairment was identified within the operating segment or the associated allocated goodwill.

21. DEBT AND CREDIT FACILITIES

Debt and credit facilities are comprised of the following:

Short-Term Debt

($ millions)	Dec 31 2014	Dec 31 2013
Commercial paper[1]	**806**	798

(1) The commercial paper is supported by a revolving credit facility with a syndicate of lenders. The company is authorized to issue commercial paper to a maximum of $2.5 billion having a term not to exceed 365 days. The weighted average interest rate as at December 31, 2014 was 0.3% (December 31, 2013 – 0.3%).

Long-Term Debt

($ millions)	Dec 31 2014	Dec 31 2013
Fixed-term debt, redeemable at the option of the company		
6.85% Notes, due 2039 (US$750)	**870**	798
6.80% Notes, due 2038 (US$900)	**1 071**	983
6.50% Notes, due 2038 (US$1150)	**1 334**	1 223
5.95% Notes, due 2035 (US$600)	**652**	596
5.95% Notes, due 2034 (US$500)	**580**	532
5.35% Notes, due 2033 (US$300)	**306**	279
7.15% Notes, due 2032 (US$500)	**580**	532
3.60% Notes, due 2024 (US$750) [2]	**864**	—
3.10% Series 5 Medium Term Notes, due 2021 [3]	**747**	—
6.10% Notes, due 2018 (US$1250)	**1 450**	1 330
6.05% Notes, due 2018 (US$600)	**703**	646
5.00% Notes, due 2014 (US$400)	**—**	427
7.00% Debentures, due 2028 (US$250)	**298**	274
7.875% Debentures, due 2026 (US$275)	**348**	321
9.25% Debentures, due 2021 (US$300)	**404**	378
5.39% Series 4 Medium Term Notes, due 2037	**600**	600
5.80% Series 4 Medium Term Notes, due 2018	**700**	700
Total unsecured long-term debt	**11 507**	9 619
Secured long-term debt	**13**	13
Finance leases[4]	**1 054**	1 071
Deferred financing costs	**(51)**	(43)
	12 523	10 660
Current portion of long-term debt		
Finance leases	**(21)**	(17)
Secured long-term debt	**(13)**	(13)

5.00% Notes, due 2014 (US$400)	—	(427)
	(34)	(457)
Total long-term debt	**12 489**	10 203

(2) In November 2014, the company issued US$750 million of senior unsecured notes maturing on December 1, 2024 under a $2 billion U.S. base shelf prospectus. The notes have a coupon of 3.60% and were priced at $99.235 per note for an effective yield of 3.692%. Interest is paid semi-annually.

(3) In November 2014, the company issued $750 million of senior unsecured Series 5 Medium Term Notes maturing on November 26, 2021 under a $2 billion Canadian base shelf prospectus. The notes have a coupon of 3.10% and were priced at $99.663 per note for an effective yield of 3.154%. Interest is paid semi-annually.

(4) Interest rates range from 4.6% to 13.4% and maturity dates range from 2017 to 2038.

Scheduled Debt Repayments

Scheduled principal repayments for finance leases, short-term debt and long-term debt are as follows:

($ millions)	Repayment
2015	840
2016	23
2017	20
2018	2 868
2019	25
Thereafter	9 562
	13 338

Credit Facilities

A summary of available and unutilized credit facilities is as follows:

($ millions)	2014
Fully revolving for a period of one year after term-out date (April 2016)	**2 000**
Fully revolving and expires in 2016	**1 550**
Fully revolving for a period of four years and expires in April 2019	**3 000**
Can be terminated at any time at the option of the lenders	**138**
Total credit facilities	**6 688**
Credit facilities supporting outstanding commercial paper	**(806)**
Credit facilities supporting standby letters of credit (1)	**(1 607)**
Total unutilized credit facilities	**4 275**

(1) To reduce costs, the company supported certain credit facilities with $1 525 million of cash collateral as at December 31, 2014 (December 31, 2013 – $585 million).

22. OTHER LONG-TERM LIABILITIES

($ millions)	Dec 31 2014	Dec 31 2013
Pensions and other post-retirement benefits (note 23)	**1 222**	926
Share-based compensation plans (note 26)	**341**	335
Deferred revenue	**66**	72
Libya EPSAs signature bonus(1)	**73**	64
Other	**85**	67
	1 787	1 464

(1) As part of the 2009 acquisition of Petro-Canada, the company assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of six EPSAs in Libya. At December 31, 2014, the carrying amount of the Libya EPSAs signature bonus was $79 million (December 31, 2013 – $78 million). The current portion is $6 million (December 31, 2013 – $14 million) and is recorded in Accounts Payable and Accrued Liabilities.

23. PENSIONS AND OTHER POST-RETIREMENT BENEFITS

The company's defined benefit pension plans provide pension benefits at retirement based on years of service and final average earnings (if applicable). These obligations are met through funded registered retirement plans and through unregistered supplementary pensions that are voluntarily funded through retirement compensation arrangements, and/or paid directly to recipients. The amount and timing of future funding for these supplementary plans is subject to the funding policy as approved by the Board of Directors. The company's contributions to the funded plans are deposited with independent trustees who act as custodians of the plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Asset-Liability matching studies are performed by a third-party consultant to set the asset mix by quantifying the risk-and-return characteristics of possible asset mix strategies. Investment and contribution policies are integrated within this study, and areas of focus include asset mix as well as interest rate sensitivity.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the United States. The most recent valuations for the Canadian plans were performed as at December 31, 2013 and for the International plans were performed as at December 31, 2014. In addition, effective January 1, 2014, the Petro-Canada Retirement Plan and Suncor Energy Pension Plan were merged. There was no impact to the consolidated results as a result of this event. The company uses a measurement date of December 31 to value the plan assets and re-measure the accrued benefit obligation for accounting purposes.

The company's other post-retirement benefits programs are unfunded and include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

The company also provides a number of defined contribution plans, including a U.S. 401(k) savings plan, that provide for an annual contribution of 5% to 11.5% of each participating employee's pensionable earnings.

Defined Benefit Obligations and Funded Status

($ millions)	Pension Benefits 2014	Pension Benefits 2013	Other Post-Retirement Benefits 2014	Other Post-Retirement Benefits 2013
Change in benefit obligation				
Benefit obligation at beginning of year	**3 891**	4 137	**489**	545
Current service costs	**136**	160	**11**	13
Past service costs and adjustments	**(15)**	13	**—**	—
Plan participants' contributions	**15**	14	**—**	—
Benefits paid	**(190)**	(186)	**(17)**	(16)
Interest costs	**190**	159	**23**	21
Foreign exchange	**4**	17	**2**	2
Settlements	**1**	2	**—**	—
Actuarial remeasurement:				
Experience loss (gain) arising on plan liabilities	**16**	25	**10**	(5)
Actuarial loss (gain) arising from changes in demographic assumptions	**17**	38	**(13)**	(1)
Actuarial loss (gain) arising from changes in financial assumptions	**477**	(488)	**(7)**	(70)
Benefit obligation at end of year	**4 542**	3 891	**498**	489
Change in plan assets				
Fair value of plan assets at beginning of year	**3 293**	2 832	**—**	—
Employer contributions	**178**	220	**—**	—
Plan participants' contributions	**15**	14	**—**	—
Benefits paid	**(177)**	(178)	**—**	—
Foreign exchange	**10**	14	**—**	—
Settlements	**1**	2	**—**	—
Administrative costs	**(2)**	(2)	**—**	—
Income on plan assets	**158**	112	**—**	—
Actuarial remeasurement:				
Return on plan assets greater than discount rate	**299**	279	**—**	—
Fair value of plan assets at end of year	**3 775**	3 293	**—**	—
Net unfunded obligation	**767**	598	**498**	489

Of the total net unfunded obligation as at December 31, 2014, 85% relates to Canadian pension and other post-retirement benefits obligation (excluding Syncrude) (December 31, 2013 – 86%). The weighted average duration of the defined benefit obligation under the Canadian pension and other post-retirement plans (excluding Syncrude) is 14.1 years (2013 – 14.0 years).

The net unfunded obligation is recorded in Accounts Payable and Accrued Liabilities and Other Long-Term Liabilities (note 22) in the Consolidated Balance Sheets.

($ millions)	Pension Benefits 2014	Pension Benefits 2013	Other Post-Retirement Benefits 2014	Other Post-Retirement Benefits 2013
Analysis of amount charged to earnings:				
Current service costs	**136**	160	**11**	13
Past service costs	**—**	13	**—**	—
Interest costs	**32**	47	**23**	21
Defined benefit plans expense	**168**	220	**34**	34
Defined contribution plans expense	**69**	62	**—**	—
Total benefit plans expense charged to earnings	**237**	282	**34**	34

Components of defined benefit costs recognized in Other Comprehensive Income:

($ millions)	Pension Benefits 2014	Pension Benefits 2013	Other Post-Retirement Benefits 2014	Other Post-Retirement Benefits 2013
Return on plan assets (excluding amounts included in net interest expense)	**(299)**	(279)	**—**	—
Experience loss (gain) arising on plan liabilities	**16**	25	**9**	(5)
Actuarial loss (gain) arising from changes in financial assumptions	**477**	(488)	**(7)**	(70)
Actuarial loss (gain) arising from changes in demographic assumptions	**17**	38	**(13)**	(1)
Actuarial loss (gain) recognized in other comprehensive income	**211**	(704)	**(11)**	(76)

Actuarial Assumptions

The cost of the defined benefit pension plans and other post-retirement benefits received by employees is actuarially determined using the projected unit credit method of valuation that includes employee service to date and present pay levels, as well as projection of salaries and service to retirement.

The significant weighted average actuarial assumptions were as follows:

(%)	Pension Benefits Dec 31 2014	Pension Benefits Dec 31 2013	Other Post-Retirement Benefits Dec 31 2014	Other Post-Retirement Benefits Dec 31 2013
Discount rate	**3.95**	4.70	**3.90**	4.70
Rate of compensation increase	**3.45**	3.45	**3.35**	3.30

The discount rate assumption is based on the interest rate on high-quality bonds with maturity terms equivalent to the benefit obligations.

The defined benefit obligation reflects the best estimate of the mortality of plan participants both during and after their employment. The mortality assumption is based on a standard mortality table adjusted for actual experience over the past five years.

In order to measure the expected cost of other post-retirement benefits, it was assumed for 2014 that the health care costs would increase annually by 7% per person (2013 – 7%). This rate will remain constant in 2015 and will decrease 0.5% annually to 5% by 2020, and remain at that level thereafter.

Assumed discount rates, longevity rates and health care cost trend rates may have a significant effect on the amounts reported for pensions and other post-retirement benefit obligations for the company's Canadian plans. A change of these assumed assumptions would have the following effects:

	Pension Benefits	
($ millions)	Increase	Decrease
1% change in discount rate		
Effect on the aggregate service and interest costs	(17)	21
Effect on the benefit obligations	(529)	671
One year change in longevity rate		
Effect on the aggregate service and interest costs	6	(6)
Effect on the benefit obligations	100	(103)

	Other Post-Retirement Benefits	
($ millions)	Increase	Decrease
1% change in discount rate		
Effect on the benefit obligations	(58)	72
1% change in health care cost		
Effect on the aggregate service and interest costs	2	(1)
Effect on the benefit obligations	27	(22)

Plan Assets and Investment Objectives

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

The company's weighted average pension plan asset allocations, based on market values as at December 31, are as follows:

(%)	**2014**	2013
Equities, comprised of:		
– Canada	**18**	18
– United States	**24**	22
– Foreign	**18**	20
	60	60
Fixed income, comprised of:		
– Canada	**40**	40
Total	**100**	100

Equity securities do not include any direct investments in Suncor shares. The fair value of equity and bond securities are based on the trading price of the underlying fund.

During the year, the company made cash contributions of $178 million to its defined benefit pension plans, of which $50 million was contributed to the solvency reserve account in Alberta. The company expects to make cash contributions to its defined benefit pension plans in 2015 of $126 million.

24. PROVISIONS

($ millions)	Decommissioning and Restoration[1]	Royalties[2]	Other[3]	Total
At December 31, 2012	4 688	367	733	5 788
Liabilities incurred	398	224	97	719
Change in discount rate	(542)	—	—	(542)
Changes in estimates	624	(15)	(392)	217
Liabilities settled	(423)	(52)	(132)	(607)
Accretion	174	—	5	179
Asset divestitures	(714)	—	—	(714)
Foreign exchange	33	—	3	36
At December 31, 2013	4 238	524	314	5 076
Less: current portion	(362)	(524)	(112)	(998)
	3 876	—	202	4 078
At December 31, 2013	4 238	524	314	5 076
Liabilities incurred	**256**	**23**	**52**	**331**
Change in discount rate	**409**	**—**	**—**	**409**
Changes in estimates	**376**	**(90)**	**(41)**	**245**
Liabilities settled	**(364)**	**(185)**	**(55)**	**(604)**
Accretion	**186**	**—**	**3**	**189**
Asset divestitures	**(39)**	**—**	**—**	**(39)**
Foreign exchange	**39**	**—**	**1**	**40**
At December 31, 2014	**5 101**	**272**	**274**	**5 647**
Less: current portion	**(369)**	**(272)**	**(111)**	**(752)**
	4 732	**—**	**163**	**4 895**

(1) Represents decommissioning and restoration provisions associated with the retirement of Property, Plant and Equipment and Exploration and Evaluation assets. The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2014 was approximately $8.9 billion (December 31, 2013 – $8.0 billion). A weighted average credit-adjusted risk-free interest rate of 3.93% was used to discount the provision recognized at December 31, 2014 (December 31, 2013 – 4.51%). The credit-adjusted risk-free rate used reflects the expected time frame of the provisions. Payments to settle the decommissioning and restoration provisions occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 50 years.

(2) During 2014, after reaching an agreement with the Government of Alberta, the company settled a provision related to several outstanding issues under the Royalty Amending Agreements entered into in 2008.

(3) For the year ended December 31, 2013, the company's other provisions decreased by $300 million as a result of the recognition of risk mitigation proceeds to earnings. In addition, the company divested one of its pipeline commitments to a third party, resulting in a $76 million decrease to provisions.

Sensitivities

Changes to the discount rate would have the following impact on Decommissioning and Restoration liabilities:

As at December 31,	**2014**	2013
1% Increase	**(665)**	(579)
1% Decrease	**909**	704

25. SHARE CAPITAL

Authorized

Common Shares

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares

The company is authorized to issue an unlimited number of senior and junior preferred shares in series, without nominal or par value.

Normal Course Issuer Bid

On August 5, 2014, Suncor renewed its normal course issuer bid (NCIB) to continue to purchase shares under its previously announced buyback program through the facilities of the Toronto Stock Exchange, New York Stock Exchange and/or alternative trading platforms (the 2014 NCIB). Pursuant to the 2014 NCIB, Suncor may purchase for cancellation up to approximately $1.1 billion worth of its common shares between August 5, 2014 and August 4, 2015 and has agreed that it will not purchase more than 44,045,388 common shares, which was equal to approximately 3% of Suncor's issued and outstanding common shares at the time of the program renewal.

As of December 31, 2014, repurchases under the program have been suspended in response to the lower crude price environment.

The following table summarizes the share repurchase activities during the period:

($ millions, except as noted)	**2014**	2013
Share repurchase activities (thousands of common shares)		
Shares repurchased	**42 027**	49 492
Amounts charged to		
Share capital	**553**	648
Retained earnings	**1 118**	1 027
Share repurchase cost	**1 671**	1 675
Average repurchase cost per share	**39.76**	33.85

Under an automatic repurchase plan agreement with an independent broker, the company has recorded the following liability for share repurchases that may take place during its internal blackout period:

($ millions)	**Dec 31 2014**	Dec 31 2013
Amounts charged to		
Share capital	—	108
Retained earnings	—	198
Liability for share purchase commitment	—	306

Dividends declared

On February 4, 2015, the company's Board of Directors approved a quarterly dividend of $0.28 per share on its common shares, payable March 25, 2015 to shareholders of record at the close of business on March 4, 2015.

26. SHARE-BASED COMPENSATION

(A) Equity-Settled Plans

Stock options that give the holder the right to purchase common shares at the grant date market price, subject to fulfilling vesting terms, are accounted for as equity-settled plans.

(i) Stock Option Plan

This plan replaced the pre-merger stock option plans of legacy Suncor and legacy Petro-Canada. Options granted have a seven-year life and vest annually over a three-year period.

The weighted average fair values of the options granted during the period and the weighted average assumptions used in their determination are as noted below:

	2014	2013
Annual dividend per share	**$1.02**	$0.73
Risk-free interest rate	**1.51%**	1.40%
Expected life	**5 years**	5 years
Expected volatility	**28%**	48%
Weighted average fair value per option	**$7.08**	$11.72

The expected life is based on historical experience and current expectations. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the options is indicative of future trends.

(ii) Discontinued Plans

The following plans were in place prior to August 1, 2009: SunShare 2012 Performance Stock Options, Executive Stock Options, and Key Contributor Stock Options. Options granted under these plans generally have a seven to ten-year life and vest over periods of up to four years.

(B) Cash-Settled Plans

(i) Cash-Settled Stock Option Plans

Stock options that the holder can settle for cash or common shares are accounted for as cash-settled plans.

(a) Suncor Energy Inc. Stock Options with TSARs

Options were granted under this plan between August 1, 2009 and July 31, 2010. Each option included a tandem stock appreciation right (TSAR). Options granted have a seven-year life and vest annually over a three-year period.

(b) Legacy Petro-Canada Stock Options with CPAs

This plan was discontinued on August 1, 2009. Options were granted to executives and key employees, and can be settled in common shares or exchanged for a cash payment alternative (CPA). Options granted have a seven-year life and vest over periods of up to four years.

Changes in the total outstanding stock options were as follows:

	2014		2013	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**34 997**	**37.54**	47 324	38.33
Granted	**5 935**	**36.29**	4 209	32.50
Exercised for cash payment	**(157)**	**34.70**	(281)	27.34
Exercised as options for common shares	**(7 831)**	**31.48**	(4 750)	23.31
Forfeited/expired	**(5 480)**	**47.81**	(11 505)	45.57
Outstanding, end of year	**27 464**	**36.97**	34 997	37.47
Exercisable, end of year	**18 084**	**37.95**	27 104	38.31

Options are exercised regularly throughout the year. Therefore, the weighted average share price during the year of $40.13 (2013 – $33.66) is representative of the weighted average share price at the date of exercise.

For the options outstanding at December 31, 2014, the exercise price ranges and weighted average remaining contractual lives are shown below:

	Outstanding	
Exercise Prices ($)	Number (thousands)	Weighted Average Remaining Contractual Life (years)
19.44-29.99	1 589	2
30.00-39.99	16 221	5
40.00-49.99	9 484	3
50.00-59.99	144	3
60.00-69.97	26	3
Total	27 464	4

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

(thousands)	**2014**	2013
	24 484	29 817

(ii) Share Unit Plans

The company's share unit plans are accounted for as cash-settled plans.

A performance share unit (PSU) is a time-vested award entitling employees to receive varying degrees of cash (0% – 200% of the company's share price at time of vesting) contingent upon Suncor's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. PSUs vest approximately three years after the grant date.

A restricted share unit (RSU) is a time-vested award entitling employees to receive cash equal to the company's share price at the time of vesting. RSUs vest approximately three years after the grant date.

A deferred share unit (DSU) is redeemable for cash or a common share for a period of time after a unitholder ceases employment or Board membership. The DSU plan is limited to executives and members of the Board of Directors. Members of the Board of Directors receive an annual grant of DSUs as part of their compensation and may elect to receive their fees in cash only or in increments of 50% or 100% allocated to DSUs. Executives may elect to receive their annual incentive bonus in cash only or in increments of 25%, 50%, 75% or 100% DSUs. Changes in the number of outstanding share units were as follows:

(thousands)	PSU	RSU	DSU
Outstanding, December 31, 2012	4 378	12 865	1 637
Granted	1 082	7 365	165
Redeemed for cash	(1 684)	(2 526)	(764)
Forfeited/expired	(135)	(658)	—
Outstanding, December 31, 2013	3 641	17 046	1 038
Granted	**842**	**7 024**	**214**
Redeemed for cash	**(1 066)**	**(3 798)**	**(207)**
Forfeited/expired	**(821)**	**(672)**	**—**
Outstanding, December 31, 2014	**2 596**	**19 600**	**1 045**

(iii) Stock Appreciation Rights (SARs)

A SAR entitles the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of the company's common shares on the date the SAR is exercised, and is accounted for as a cash-settled plan.

(a) Suncor Energy Inc. SARs

These SARs have a seven-year life and vest annually over a three-year period.

(b) Legacy Petro-Canada SARs

This plan was discontinued on August 1, 2009. These SARs have a seven-year life and vest annually over a four-year period.

Changes in the number of outstanding SARs were as follows:

	2014		2013	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**5 805**	**29.75**	7 776	29.65
Granted	**99**	**36.05**	88	32.60
Exercised	**(3 248)**	**31.88**	(1 567)	27.57
Forfeited/expired	**(93)**	**36.70**	(492)	35.47
Outstanding, end of year	**2 563**	**27.05**	5 805	29.75
Exercisable, end of year	**2 409**	**26.54**	5 665	29.61

Share-Based Compensation Expense

The following table summarizes the share-based compensation expense recorded for all plans within Operating, Selling and General expense.

($ millions)	2014	2013
Equity-settled plans	**42**	51
Cash-settled plans	**266**	341
Total share-based compensation expense	**308**	392

Liability Recognized for Share-Based Compensation

The following table summarizes the share-based compensation fair value recorded in accounts payable and accrued liabilities and other long-term liabilities for all cash-settled plans:

($ millions)	2014	2013
Current Liability	**327**	318
Long-term Liability (note 22)	**341**	335
Total Liability	**668**	653

The intrinsic value of the vested awards at December 31, 2014 was $349 million (December 31, 2013 – $347 million).

27. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all accounts payable and accrued liabilities, debt, and certain portions of other assets and other long-term liabilities.

Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable, short-term debt, and accounts payable and accrued liabilities approximate their carrying values due to the short-term maturities of those instruments.

The company's long-term debt and long-term financial liabilities are recorded at amortized cost using the effective interest method. At December 31, 2014, the carrying value of fixed-term debt accounted for under amortized cost was $11.5 billion (December 31, 2013 – $9.6 billion) and the fair value at December 31, 2014 was $13.5 billion (December 31, 2013 – $11.2 billion). The estimated fair value of long-term debt is based on pricing sourced from market data, which is considered a Level 2 fair value input.

Derivative Financial Instruments

(a) Non-Designated Derivative Financial Instruments

- Energy Trading Derivatives – The company's Energy Trading group uses physical and financial energy derivative contracts, including swaps, forwards and options to earn trading revenues.
- Risk Management Derivatives – The company periodically enters into derivative contracts in order to manage exposure to commodity price and foreign exchange movements and are a component of the company's overall risk management program.

The changes in the fair value of non-designated Energy Trading and Risk Management derivatives are as follows:

($ millions)	Assets Available for Sale	Energy Trading	Risk Management	Total
Fair value of contracts outstanding at January 1, 2013	—	(43)	(1)	(44)
Fair value of contracts realized in earnings during the year	—	(271)	18	(253)
Changes in fair value during the year (note 8)	—	176	(18)	158
Fair value of contracts outstanding at December 31, 2013	—	(138)	(1)	(139)
Fair value of contracts realized in earnings during the year	**—**	**(15)**	**(65)**	**(80)**
Changes in fair value during the year (note 8)	**—**	**173**	**176**	**349**
Assets available for sale during the year (note 36)	**183**	**—**	**—**	**183**
Fair value outstanding at December 31, 2014	**183**	**20**	**110**	**313**

(b) Fair Value Hierarchy

To estimate the fair value of derivatives, the company uses quoted market prices when available, or third-party models and valuation methodologies that utilize observable market data. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 consists of instruments with a fair value determined by an unadjusted quoted price in an active market for identical assets or liabilities. An active market is characterized by readily and regularly available quoted prices where the prices are representative of actual and regularly occurring market transactions to assure liquidity.
- Level 2 consists of instruments with a fair value that is determined by quoted prices in an inactive market, prices with observable inputs, or prices with insignificant non-observable inputs. The fair value of these positions is determined using observable inputs from exchanges, pricing services, third-party independent broker quotes, and

published transportation tolls. The observable inputs may be adjusted using certain methods, which include extrapolation over the quoted price term and quotes for comparable assets and liabilities.

- Level 3 consists of instruments with a fair value that is determined by prices with significant unobservable inputs. As at December 31, 2014, the company does not have any derivative instruments measured at fair value Level 3.

In forming estimates, the company utilizes the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorized based upon the lowest level of input that is significant to the fair value measurement.

The following table presents the company's derivative financial instrument assets and liabilities and assets available for sale measured at fair value for each hierarchy level as at December 31, 2014 and 2013.

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	137	88	—	225
Accounts payable	(165)	(199)	—	(364)
Balance at December 31, 2013	(28)	(111)	—	(139)
Accounts receivable	**154**	**57**	**—**	**211**
Accounts payable	**(5)**	**(76)**	**—**	**(81)**
Assets available for sale	**—**	**183**	**—**	**183**
Balance at December 31, 2014	**149**	**164**	**—**	**313**

During the year ended December 31, 2014, there were no transfers between Level 1 and Level 2 fair value measurements.

Offsetting Financial Assets and Liabilities

The company enters into arrangements that allow for offsetting of derivative financial instruments and accounts receivable (payable), which are presented on a net basis on the balance sheet, as shown in the table below as at December 31, 2014 and 2013.

Financial Assets

($ millions)	Gross assets	Gross liabilities offset	Net amounts presented
Derivatives	225	(185)	40
Accounts receivable	3 092	(967)	2 125
Balance at December 31, 2013	3 317	(1 152)	2 165
Derivatives	**1 520**	**(1 309)**	**211**
Accounts receivable	**1 603**	**(612)**	**991**
Balance at December 31, 2014	**3 123**	**(1 921)**	**1 202**

Financial Liabilities

($ millions)	Gross liabilities	Gross assets offset	Net amounts presented
Derivatives	(364)	185	(179)
Accounts payable	(2 956)	967	(1 989)
Balance at December 31, 2013	(3 320)	1 152	(2 168)
Derivatives	**(1 390)**	**1 309**	**(81)**
Accounts payable	**(1 642)**	**612**	**(1 030)**
Balance at December 31, 2014	**(3 032)**	**1 921**	**(1 111)**

Risk Management

The company is exposed to a number of different risks arising from financial instruments. These risk factors include market risks, comprising commodity price risk, foreign currency risk and interest rate risk, as well as liquidity risk and credit risk.

The company maintains a formal governance process to manage its financial risks. The company's Commodity Risk Management Committee (CRMC) is charged with the oversight of the company's trading and credit risk management activities. Trading activities are defined as activities intended to enhance the company's operations and enhance profitability through informed market calls, market diversification, economies of scale, improved transportation access, and leverage of assets, both physical and contractual. The CRMC, acting under the authority of the company's Board of Directors, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures.

The nature of the risks faced by the company and its policies for managing such risks remains unchanged from December 31, 2013.

1) Market Risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the company's financial assets, liabilities and expected future cash flows include commodity price risk, foreign currency exchange risk and interest rate risk.

(a) Commodity Price Risk

Suncor's financial performance is closely linked to crude oil prices (including pricing differentials for various product types) and, to a lesser extent, natural gas and refined product prices. The company may reduce its exposure to commodity price risk through a number of strategies. These strategies include entering into option contracts to limit exposure to changes in crude oil prices during transportation.

An increase of US$1.00 per barrel of crude oil as at December 31, 2014 would decrease pre-tax earnings for the company's outstanding derivative financial instruments by approximately $10 million (2013 – $2 million).

(b) Foreign Currency Exchange Risk

The company is exposed to foreign currency exchange risk on revenues, capital expenditures, or financial instruments that are denominated in a currency other than the company's functional currency (Canadian dollars). As crude oil is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. This exposure is partially offset through the issuance of U.S. dollar denominated debt. A 1% strengthening in the Cdn$ relative to the US$ as at December 31, 2014 would decrease pre-tax earnings by approximately $110 million (2013 – $90 million).

The company also has foreign operations whose functional currency is different than the company's functional currency. The main exposures relate to foreign operations whose functional currencies are in U.S. dollars, euros (€) or pound sterling (£). A 1% strengthening in the Cdn$ relative to the US$, € and £ as at December 31, 2014 would decrease Other Comprehensive Income by approximately $43 million, $22 million and $21 million, respectively (2013 – $43 million, $26 million, and $21 million, respectively).

(c) Interest Rate Risk

The company is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair values of its financial instruments. The primary exposure is related to its revolving-term debt of commercial papers.

To manage the company's exposure to interest rate volatility, the company may periodically enter into interest rate swap contracts to fix the interest rate of future debt issuances. As at December 31, 2014, the company had executed US$100 million in forward swaps. The proportion of floating interest rate exposure at December 31, 2014 was 6.5% of total debt outstanding. The weighted average interest rate on total debt for the year ended December 31, 2014 was 6.0%.

The company's net earnings are sensitive to changes in interest rates on the floating rate portion of the company's debt. To the extent interest expense is not capitalized, if interest rates applicable to floating rate instruments increased by 1%, it is estimated that the company's pre-tax earnings would decrease by approximately $11 million (2013 – $8 million). This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2014, and that the change in interest rates is effective from the beginning of the year.

2) Liquidity Risk

Liquidity risk is the risk that Suncor will not be able to meet its financial obligations when due. The company mitigates this risk by forecasting spending requirements as well as cash flow from operations, and maintaining sufficient cash, credit facilities, and debt shelf prospectuses to meet these requirements. Suncor's cash and cash equivalents and total credit facilities at December 31, 2014 were $5.5 billion and $6.7 billion, respectively. Of Suncor's $6.7 billion in total credit facilities, $2.4 billion was drawn down at December 31, 2014. In addition, Suncor has in place an unused capacity of $1.25 billion under a Canadian debt shelf prospectus, and an unused capacity of $1.25 billion under the U.S. debt shelf prospectus.

Surplus cash is invested into a range of short-dated money market securities. Investments are only permitted in high credit quality government or corporate securities. Diversification of these investments is maintained through counterparty credit limits.

The following table shows the timing of cash outflows related to trade and other payables and debt.

	December 31, 2013		
($ millions)	Trade and other payables[1]	Gross derivative liabilities[2]	Debt[3]
Within one year	6 911	353	1 959
1 to 3 years	64	11	1 402
3 to 5 years	—	—	4 064
Over 5 years	—	—	15 746
	6 975	364	23 171

	December 31, 2014		
($ millions)	**Trade and other payables[1]**	**Gross derivative liabilities[2]**	**Debt[3]**
Within one year	**5 623**	**1 390**	**1 621**
1 to 3 years	**23**	**—**	**1 604**
3 to 5 years	**50**	**—**	**4 280**
Over 5 years	**—**	**—**	**18 160**
	5 696	**1 390**	**25 665**

(1) Trade and other payables exclude net derivative liabilities of $81 million (2013 – $179 million)

(2) Gross derivative liabilities of $1 390 million (2013 – $364 million) are offset by gross derivative assets of $1 309 million (2013 – $185 million), resulting in a net amount of $81 million (2013 – $179 million).

(3) Debt includes short-term debt, long-term debt, finance leases and interest payments on fixed-term debt and commercial paper.

3) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. The company's credit policy is designed to ensure there is a standard credit practice throughout the company to measure and monitor credit risk. The policy outlines delegation of authority, the due diligence process required to approve a new customer or counterparty and the maximum amount of credit exposure per single entity. Before transactions begin with a new customer or counterparty, its creditworthiness is assessed, a credit rating is assigned and a maximum credit limit is allocated. The assessment process is outlined in the credit policy and considers both quantitative and qualitative factors. The company constantly monitors the exposure to any single customer or counterparty along with the financial position of the customer or counterparty. If it is deemed that a customer or counterparty has become materially weaker, the company will work to reduce the credit exposure and lower the credit limit allocated. Regular reports are generated to monitor credit risk and the Credit Committee meets quarterly to ensure compliance with the credit policy and review the exposures.

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. At December 31, 2014, substantially all of the company's trade receivables were current.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts owing to the company at the reporting date. At December 31, 2014, the company's exposure was $1.520 billion (December 31, 2013 – $225 million).

28. CAPITAL STRUCTURE FINANCIAL POLICIES

The company's primary capital management strategy is to maintain a conservative balance sheet, which supports a solid investment grade credit rating profile. This objective affords the company the financial flexibility and access to the capital it requires to execute on its growth objectives.

The company's capital is primarily monitored by reviewing the ratios of net debt to cash flow from operations [(1)] and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus total long-term debt less cash and cash equivalents divided by cash flow from operations for the year then ended.

Total debt to total debt plus shareholders' equity is calculated as short-term debt plus total long-term debt divided by short-term debt plus total long-term debt plus shareholders' equity. This financial covenant under the company's various banking and debt agreements shall not be greater than 65%.

The company's financial covenant is reviewed regularly and controls are in place to maintain compliance with the covenant. The company complied with financial covenants for the years ended December 31, 2014 and 2013. The company's financial measures, as set out in the following schedule, were unchanged from 2013. The company believes that achieving its capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment grade credit ratings. The company operates in a fluctuating business environment and ratios may periodically fall outside of management's targets.

($ millions)	Capital Measure Target	Dec 31 2014	Dec 31 2013
Components of ratios			
Short-term debt		**806**	798
Current portion of long-term debt		**34**	457
Long-term debt		**12 489**	10 203
Total debt		**13 329**	11 458
Less: Cash and cash equivalents		**5 495**	5 202
Net debt		**7 834**	6 256
Shareholders' equity		**41 603**	41 180
Total capitalization (total debt plus shareholders' equity)		**54 932**	52 638
Cash flow from operations[1]		**9 058**	9 412
Net debt to cash from operations	<2.0 times	**0.9**	0.7
Total debt to total debt plus shareholders' equity		**24%**	22%

(1) Cash flow from operations is expressed before changes in non-cash working capital, and is a non-GAAP financial measure.

29. JOINT ARRANGEMENTS

Joint Operations

The company's material joint operations as at December 31, 2014 are set out below:

Material Joint Operations	Principal activity	Country of incorporation and principal place of business	Ownership % 2014	Ownership % 2013
Oil Sands				
Operated by Suncor:				
Fort Hills Energy Limited Partnership	Oil sands development	Canada	40.80	40.80
Non-operated:				
Syncrude	Oil sands development	Canada	12.00	12.00
Joslyn	Oil sands development	Canada	36.75	36.75
Exploration and Production				
Operated by Suncor:				
Terra Nova	Oil and gas production	Canada	37.68	37.68
Non-operated:				
White Rose and the White Rose Extensions	Oil and gas production	Canada	26.13-27.50	26.13-27.50
Hibernia and the Hibernia South Extension Unit	Oil and gas production	Canada	19.51-20.00	19.51-20.00
Hebron	Oil and gas production	Canada	22.73	22.73
Harouge Oil Operations	Oil and gas production	Libya	49.00	49.00
Buzzard	Oil and gas production	United Kingdom	29.89	29.89

Golden Eagle Area Development	Oil and gas production	United Kingdom	26.69	26.69

Joint Ventures and Associates

The company does not have any joint ventures or associates that are considered individually material. Summarized aggregate financial information of the joint ventures and associates in the company's refining and marketing operations are shown below:

	Joint ventures		Associates	
($ millions)	**2014**	2013	**2014**	2013
Net earnings	**3**	9	**7**	10
Other comprehensive income (loss)	**6**	(2)	**—**	—
Total comprehensive income	**9**	7	**7**	10
Carrying amount as at December 31	**119**	120	**51**	46

30. SUBSIDIARIES

Material subsidiaries, each of which is wholly owned, either directly or indirectly, by the company as at December 31, 2014, are shown below:

Material Subsidiaries	Principal activity
Canadian Operations	
Suncor Energy Oil Sands Limited Partnership	This partnership holds most of the company's oil sands and in situ assets.
Suncor Energy Products Inc.	This subsidiary holds interests in the company's energy marketing and renewable energy businesses.
Suncor Energy Products Partnership	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Marketing Inc.	A subsidiary of Suncor Energy Products Inc. through which production from our upstream North American businesses is marketed. Through this subsidiary, we also administer Suncor's energy trading activities and power business, market certain third-party products, procure crude oil feedstock and natural gas for our downstream business, and procure and market NGLs and LPG for our downstream business.
U.S. Operations	
Suncor Energy (U.S.A.) Marketing Inc.	A subsidiary that procures and markets third-party crude oil, in addition to procuring crude oil feedstock for the company's refining operations.
Suncor Energy (U.S.A.) Inc.	A subsidiary through which the company's U.S. refining and marketing operations are conducted.
International Operations	
Suncor Energy UK Limited	A subsidiary through which the majority of the company's North Sea operations are conducted.
Suncor Energy Oil (North Africa) GmbH	A subsidiary through which the majority of the company's Libya operations are conducted.

The table does not include wholly owned subsidiaries that are immediate holding companies of the operating subsidiaries. For certain foreign operations of the company, there are restrictions on the sale or transfer of production licences, which would require approval of the applicable foreign government.

31. RELATED PARTY DISCLOSURES

Related Party Transactions

The company enters into transactions with related parties in the normal course of business, which includes purchases of feedstock, distribution of refined products, and sale of refined products and by-products. These transactions are with joint ventures and associated entities in the company's refining and marketing operations, including pipeline, refined product and petrochemical companies. A summary of the significant related party transactions as at and for the year ended December 31, 2014 and 2013 are as follows:

($ millions)	**2014**	2013
Sales	**1 543**	1 593
Purchases	**312**	245
Accounts receivable	**80**	92
Accounts payable and accrued liabilities	**8**	15

Compensation of Key Management Personnel

Compensation of the company's Board of Directors and members of the Executive Leadership Team for the years ended December 31 is as follows:

($ millions)	**2014**	2013
Salaries and other short-term benefits	**11**	14
Pension and other post-retirement benefits	**4**	4
Share-based compensation	**34**	35
	49	53

32. COMMITMENTS, CONTINGENCIES AND GUARANTEES

(a) Commitments

Future payments under the company's commitments, including operating leases for pipeline transportation agreements and for various premises, service stations and other property and equipment, are as follows:

	Payment due by period						
($ millions)	2015	2016	2017	2018	2019	2020 and beyond	**Total**
Commitments							
Product transportation and storage	694	630	604	558	497	3 790	**6 773**
Energy services	233	183	178	180	181	866	**1 821**
Drilling commitments	86	43	21	—	—	—	**150**
Exploration work commitments	146	26	—	141	108	253	**674**
Other	183	56	37	38	36	377	**727**
Operating leases	532	508	424	350	317	1 783	**3 914**
	1 874	1 446	1 264	1 267	1 139	7 069	**14 059**

Significant operating leases expire at various dates through 2035. For the year ended December 31, 2014, operating lease expense was $0.6 billion (2013 – $0.6 billion).

In addition to the commitments in the above table, the company has other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Such obligations include

commodity purchase obligations which are transacted at market prices. The company has also entered into various pipeline commitments of $5.7 billion with contract terms up to 25 years, which are awaiting regulatory approval. In the event regulatory approval is not obtained, the company has committed to reimbursing certain costs to the service provider.

(b) Contingencies

Legal and environmental contingent liabilities

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position, except the CRA dispute as disclosed in note 12.

The company may also have environmental contingent liabilities, beyond decommissioning and restoration liabilities recognized in note 24, which are reviewed individually and are reflected in the company's consolidated financial statements if material and more likely than not to be incurred. These contingent environmental liabilities primarily relate to the mitigation of contamination at sites where the company has had operations. For any unrecognized environmental contingencies, the company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash flow from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact is not expected to be material.

Operational risk

The company also has exposure to some operational risks, which is reduced by maintaining an insurance program.

The company carries property damage and business interruption insurance with varying coverage limits and deductible amounts based on the asset. As of December 31, 2014, Suncor's insurance program includes coverage of up to US$1.3 billion for oil sands risks, up to US$1.3 billion for offshore risks and up to US$600 million for refining risks. These limits are all net of deductible amounts or waiting periods and subject to certain price and volume limits. The company also has primary property insurance for US$300 million that covers all of Suncor's assets. As part of its normal course of operations, Suncor also carries risk mitigation instruments in the aggregate amount of $300 million on certain foreign operations.

Suncor believes its liability, property and business interruption insurance is appropriate to its business, although such insurance will not provide coverage in all circumstances or fully protect against prolonged outages. In the future, the insurance program may change due to market conditions or other business considerations.

(c) Guarantees

At December 31, 2014, the company provides loan guarantees to certain retail licensees and wholesale marketers. Suncor's maximum potential amount payable under these loan guarantees is $125 million.

The company has also agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 21) for added costs relating to withholding taxes. Similar indemnity terms apply to certain facility and equipment leases. There is no limit to the maximum amount payable under these indemnification agreements. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, the company has the option to redeem or terminate these contracts if additional costs are incurred.

The company also has guaranteed its working-interest share of certain joint venture undertakings related to transportation services agreements entered into with third parties. The guaranteed amount is limited to the company's share in the joint venture. As at December 31, 2014, the probability is remote that these guarantee commitments will impact the company.

33. VOYAGEUR UPGRADER PROJECT

Management applies judgment in determining whether an acquisition meets the definition of a business combination or an asset purchase. When a transaction meets the definition of a business combination, the acquired identifiable assets and assumed liabilities, including contingent liabilities, are measured and recognized at their fair value on the date of the acquisition, including tax assets and liabilities. Associated transaction costs are expensed when occurred.

Effective March 27, 2013, the company acquired Total E&P's interest in Voyageur Upgrader Limited Partnership (VULP) for $515 million and gained full control over the partnership assets. The transaction was accounted for as a business combination.

As VULP was in the development stage and therefore had no revenues and the majority of costs were capitalized, no significant net earnings were generated.

The fair value of consideration transferred and the assets acquired and liabilities assumed at the date of acquisition are summarized below:

($ millions)

Total purchase price	515
Allocation of purchase price:	
Property, plant and equipment	374
Deferred income taxes	312
Decommissioning and restoration provisions	(81)
Contracts and liabilities acquired	(90)
Net assets acquired	515

The fair value attributed to the property, plant and equipment acquired was based on an expected future cash flow approach for assets expected to be retained, with a risk-adjusted discount rate of 10%. For assets expected to be sold, the fair value was determined based on management's best estimate of the recoverable amount.

The fair value of the decommissioning and restoration provisions was determined based on management's best estimate of the costs to complete the reclamation activities, the timing of cash outflows, method of reclamation, the discount rate and management's anticipated use of the area in the future.

Following the acquisition, the company announced that it was not proceeding with the Voyageur upgrader project. The decision was a result of a joint strategic and economic review launched by the company and its then co-owner, Total E&P, in response to a change in market conditions that challenged the economics of the project. As a result of not proceeding with the upgrading portion of the project, a charge of $82 million was recorded to net earnings in 2013, including costs related to the acceleration of certain reclamation activities.

34. PROPERTY ACQUISITION

On July 17, 2014, the company completed a business combination of a sulphur recovery facility in its Refining and Marketing segment.

The purchase price allocation is based on management's best estimates of the fair value of the acquired assets and assumed liabilities. Upon finalization, adjustments to the initial estimates may be required.

The aggregate consideration for this business combination was allocated as follows:

($ millions)

Total purchase price	121
Preliminary allocation of purchase price:	
Property, plant and equipment	161
Net working capital	(1)
Deferred tax liabilities	(39)
Net assets acquired	121

All acquisition and transaction costs for this asset acquisition were expensed.

35. ASSET DISPOSITIONS

The company sold its Wilson Creek assets in central Alberta for $168.5 million before closing adjustments and other closing costs, with an effective date of July 1, 2014 and a closing date of September 30, 2014. The sale of these assets resulted in an after-tax gain of $61 million in the Exploration and Production segment.

During 2013, the company sold a significant portion of its natural gas business for $1.0 billion before closing adjustments and other closing costs. An after-tax gain of $130 million was recorded in the Exploration and Production segment upon closing of the sale.

36. PIONEER DISPOSITION

During 2014, the company announced that, along with The Pioneer Group Inc., it had reached an agreement to sell the assets of Pioneer Energy, including retail gas stations in Ontario and Manitoba. The company, as a 50% owner of Pioneer Energy, will receive $182.5 million before closing adjustments for its share of the assets and liabilities. The transaction is expected to close in the first half of 2015 and is subject to closing conditions including regulatory approval under the Competition Act. The investment is classified as assets available for sale and included in Other Assets. An unrealized fair value adjustment resulted in an $85 million after-tax increase to Other Comprehensive Income during the third quarter of 2014.

37. SUSPENDED EXPLORATORY WELL COSTS

($ millions)	**2014**	2013
Beginning of year	**342**	318
Additions	**4**	24
End of year	**346**	342

The following provides an aging of amounts capitalized as suspended exploratory wells at December 31 based on the completion date of the individual well.

($ millions)	**2014**	2013
Suspended exploratory well costs that have been capitalized for a period less than one year	**—**	9
Suspended exploratory well costs that have been capitalized for a period greater than one year	**346**	333
	346	342
Number of suspended exploratory wells that have been capitalized for a period greater than one year	**9**	8

Suspended capitalized costs for exploratory wells completed prior to the end of 2014 are associated with projects located in i) Norway (three wells), ii) Libya (five wells) and iii) East Coast Canada (one well). The projects are awaiting the completion of economic evaluations, including, but not limited to, results of additional appraisal drilling, additional geological and geophysical data, and development plan approval.

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EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2014
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EXHIBIT 99-2

**Management's Discussion and Analysis for the fiscal year ended December 31, 2014,
dated February 26, 2015**

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 26, 2015

This Management's Discussion and Analysis (this MD&A) should be read in conjunction with Suncor's December 31, 2014 audited Consolidated Financial Statements and the accompanying notes. Additional information about Suncor filed with Canadian securities regulatory authorities and the United States Securities and Exchange Commission (SEC), including quarterly and annual reports and the Annual Information Form dated February 26, 2015 (the 2014 AIF), which is also filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and our website, www.suncor.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

References to "we", "our", "Suncor", or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint arrangements, unless the context requires otherwise. For a list of abbreviations that may be used in this MD&A, refer to the Advisories – Common Abbreviations section of this MD&A.

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Basis of Presentation

Unless otherwise noted, all financial information has been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and Canadian generally accepted accounting principles (GAAP) as contained within Part 1 of the Canadian Institute of Chartered Professional Accountants Handbook.

Effective January 1, 2013, Suncor adopted new and amended accounting standards, described in the Accounting Policies and Critical Accounting Estimates section of this MD&A. Comparative figures presented in this document pertaining to Suncor's 2012 results have been restated while comparative figures pertaining to Suncor's results in 2011 have not been restated in accordance with the respective transitional provisions of the new and amended standards.

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.

Non-GAAP Financial Measures

Certain financial measures in this MD&A – namely operating earnings, cash flow from operations, return on capital employed (ROCE), Oil Sands cash operating costs, free cash flow, and last-in, first-out (LIFO) – are not prescribed by GAAP. Operating earnings, Oil Sands cash operating costs and LIFO are defined in the Advisories – Non-GAAP Financial Measures section of this MD&A and reconciled to GAAP measures in the Financial Information and Segment Results and Analysis sections of this MD&A. Cash flow from operations, ROCE and free cash flow are defined and reconciled to GAAP measures in the Advisories – Non-GAAP Financial Measures section of this MD&A.

Measurement Conversions

Crude oil and natural gas liquids volumes have been converted to mcfe on the basis of one bbl to six mcf in this MD&A. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Refer to the Advisories – Measurement Conversions section of this MD&A.

Common Abbreviations

For a list of abbreviations that may be used in this MD&A, refer to the Advisories – Common Abbreviations section of this MD&A.

Risks and Forward-Looking Information

The company's financial and operational performance is potentially affected by a number of factors, including, but not limited to, the factors described in the Risk Factors section of this MD&A.

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

1. FINANCIAL AND OPERATING SUMMARY

Financial Summary

Year ended December 31 ($ millions, except per share amounts)	2014	2013	2012
Operating revenues, net of royalties	**39 862**	39 593	38 107
Net earnings	**2 699**	3 911	2 740
per common share – basic	**1.84**	2.61	1.77
per common share – diluted	**1.84**	2.60	1.76
Operating earnings[1]	**4 620**	4 700	4 847
per common share – basic	**3.15**	3.13	3.14
Cash flow from operations[1]	**9 058**	9 412	9 733
per common share – basic	**6.19**	6.27	6.30
Dividends paid on common shares	**1 490**	1 095	756
per common share – basic	**1.02**	0.73	0.50
Weighted average number of common shares in millions – basic	**1 462**	1 501	1 545
Weighted average number of common shares in millions – diluted	**1 465**	1 502	1 549
ROCE[1][2] (%)			
For the twelve months ended	**8.6**	11.5	7.2
Capital Expenditures[3]	**6 530**	6 380	6 370
Sustaining	**3 014**	3 725	3 252
Growth	**3 516**	2 655	3 118
Free cash flow[1]	**2 097**	2 635	2 776
Balance Sheet (at December 31)			
Total assets	**79 671**	78 315	76 401
Long-term debt[4]	**12 523**	10 660	10 249
Net debt	**7 834**	6 256	6 639
Total liabilities	**38 068**	37 135	37 186

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

(2) ROCE excludes capitalized costs related to major projects in progress.

(3) Excludes capitalized interest.

(4) Includes current portion of long-term debt.

Operating Summary

Year ended December 31	2014	2013	2012
Production Volumes (mboe/d)			
Oil Sands	**421.9**	392.5	359.2
Exploration and Production	**113.0**	169.9	189.9
Total	**534.9**	562.4	549.1
Production Mix			
Crude oil and liquids / natural gas (%)	**99/1**	94/6	91/9
Average Price Realizations ($/boe)			
Oil Sands operations	**87.46**	82.83	81.69
Exploration and Production	**103.05**	91.44	84.05
Refinery crude oil processed (mbbls/d)	**427.5**	431.3	431.4
Refinery Utilization[1][2] (%)			
Eastern North America	**90**	91	89
Western North America	**95**	96	100
	93	94	95

(1) Refinery utilization is the amount of crude oil run through crude distillation units, expressed as a percentage of the capacity of these units.

(2) Refinery nameplate capacity increases:

- Effective January 1, 2014, Edmonton refinery from 140,000 bbls/d to 142,000 bbls/d;
- Effective January 1, 2013, Edmonton refinery from 135,000 bbls/d to 140,000 bbls/d;
- Effective January 1, 2012, Montreal refinery from 130,000 bbls/d to 137,000 bbls/d and the Commerce City refinery from 93,000 bbls/d to 98,000 bbls/d; and
- Prior years' utilization rates have not been recalculated and reflect the lower nameplate capacities.

Segment Summary

Year ended December 31 ($ millions)	2014	2013	2012
Net earnings (loss)			
Oil Sands	**1 776**	2 040	468
Exploration and Production	**653**	1 000	138
Refining and Marketing	**1 692**	2 022	2 137
Corporate, Energy Trading and Eliminations	**(1 422)**	(1 151)	(3)
Total	**2 699**	3 911	2 740
Operating earnings (loss)[1]			
Oil Sands	**2 771**	2 098	2 025
Exploration and Production	**857**	1 210	850
Refining and Marketing	**1 692**	2 022	2 152
Corporate, Energy Trading and Eliminations	**(700)**	(630)	(180)
Total	**4 620**	4 700	4 847
Cash flow from (used in) operations[1]			

Oil Sands	**5 400**	4 556	4 407
Exploration and Production	**1 909**	2 316	2 227
Refining and Marketing	**2 178**	2 618	3 138
Corporate, Energy Trading and Eliminations	**(429)**	(78)	(39)
Total	**9 058**	9 412	9 733

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

2. SUNCOR OVERVIEW

Suncor is an integrated energy company headquartered 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; we transport and refine crude oil, and we market petroleum and petrochemical products primarily in Canada. Periodically, we market third-party petroleum products. We also conduct energy trading activities focused principally on the marketing and trading of crude oil, natural gas and byproducts.

For a description of Suncor's business segments, refer to the Segment Results and Analysis section of this MD&A.

Suncor's Strategy

We are committed to delivering competitive and sustainable returns to shareholders by focusing on capital discipline, operational excellence and long-term profitable growth, and by leveraging our competitive differentiators: an industry-leading oil sands resource base, a proven integrated model, financial strength, industry expertise and a commitment to sustainability. Key components of Suncor's strategy include:

- Profitably operate and develop our resources – Suncor's growth portfolio is focused on projects, such as Fort Hills, that are expected to provide long-term profitability for the company. The company's significant resource base and industry expertise in oil sands has laid the groundwork for achieving this growth. Suncor's economies of scale have also allowed us to focus on near-term oil sands growth through low-cost debottlenecking and expansion projects.

- Optimize value through integration – From the ground to the gas station, Suncor optimizes its profit through each step of the value chain. As upstream production grows, securing access to global pricing through the company's refining operations and midstream logistics network helps to maximize profit on each upstream barrel.

- Achieve industry leading unit costs in each business segment – Through a focus on operational excellence, Suncor is aiming to get the most out of our operations. Driving down costs and a continued focus on improved productivity and reliability will help to achieve this.

- Industry leader in sustainable development – Suncor is focused on triple bottom line sustainability, which means leadership and industry collaboration in environmental performance, social responsibility and creating a strong economy.

2014 Highlights

Financial results summary.

- Net earnings for 2014 were $2.699 billion, compared to $3.911 billion in 2013.

- Operating earnings[(1)] for 2014 were $4.620 billion, compared to $4.700 billion in 2013.

- Cash flow from operations[(1)] for 2014 was $9.058 billion, compared to $9.412 billion in 2013.

- ROCE[(1)] (excluding major projects in progress) decreased to 8.6% for the twelve months ended December 31, 2014, compared to 11.5% for the twelve months ended December 31, 2013.

Return of cash to shareholders increases by more than 14%.

- Suncor continued to deliver on its commitment to shareholders by returning $3.2 billion through dividends and share repurchases.

- The company returned $1.7 billion through the purchase of 42 million common shares in 2014, at a weighted average price of $39.76 per share. Further repurchases have been suspended in response to the current lower crude price environment.

- The company returned $1.5 billion in dividends, reflecting a 40% increase to Suncor's quarterly dividend compared to the prior year, demonstrating our dedication to returning value to shareholders.

Suncor's commitment to capital discipline, operational excellence and long-term profitable growth generated $2.1 billion in free cash flow[(1)].

- Suncor's approach to prudent capital spending in 2014 resulted in the company finishing the year $300 million below its revised 2014 capital guidance of $6.8 billion, and ending the year with $5.5 billion in cash and cash equivalents.

(1) Operating earnings, cash flow from operations, ROCE, and free cash flow are non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

- In response to a declining price environment, Suncor announced a reduction to its 2015 capital program by $1 billion, including the deferral of some projects that have not been sanctioned, without impacting the company's continued safety, reliability and environmental performance.

- A decision was made with the co-owners of the Joslyn mining project to scale back certain development activities, reinforcing the company's disciplined approach to capital allocation.

- The sale of Wilson Creek assets in the Exploration and Production (E&P) segment and the agreement to sell Pioneer Energy retail assets combined with the acquisition of a sulphur recovery facility in the Refining and Marketing segment reinforced Suncor's continued focus on assets that are aligned with the company's long-term strategy.

Continued focus on cost management enabled Suncor to decrease Oil Sands cash operating costs per barrel by 9%.

- Suncor reduced annual cash operating costs per barrel [(1)] from $37.00/bbl in 2013 to $33.80/bbl in 2014.

- Suncor's 2015 cost reduction announcement also included a $600 million to $800 million targeted reduction in operating costs to maximize profitability on each barrel of production. The current pricing environment has reinforced the importance of Suncor's disciplined approach to cost management.

Suncor's strong balance sheet has effectively positioned the company to move forward on profitable long-term growth projects.

- The Fort Hills mining project continues on schedule and all critical milestones set for 2014 have been achieved. The project is expected to produce first oil as early as the fourth quarter of 2017 with a ramp up to 90% of its planned gross production capacity of 180,000 bbls/d within twelve months.

- Golden Eagle achieved first oil during 2014 and is expected to reach peak production of approximately 18,000 boe/d (net) during 2015.

- Investments in offshore developments, including Hebron and long-term exploration opportunities in East Coast Canada and the North Sea, provide Suncor with growth opportunities in established resource basins.

Continued investment in integration and market access strategies.

- The price volatility experienced in the latter half of 2014 reinforced the importance of Suncor's strategy to enhance marketing flexibility to maximize profitability.

- Refining and Marketing increased rail shipments of inland priced crudes to the Montreal refinery, which averaged 33,000 bbls/d in 2014.

- Crude by rail, combined with the anticipated reversal of Enbridge's Line 9, is expected to provide the company with the flexibility to supply its Montreal refinery with a full slate of inland priced crude in the latter part of 2015.

- The company also increased its midstream flexibility with new logistic arrangements, including an offloading agreement at a rail and marine terminal in Tracy, Quebec and increased storage capacity at the U.S. Gulf Coast. Suncor also completed marine shipments of crude to the U.S. Gulf Coast when conditions were favourable.

- Suncor began shipments of heavy crude on TransCanada's Gulf Coast Pipeline, which provided more than 70,000 bbls/d of access to U.S. Gulf Coast pricing for both light and heavy crudes.

- The company's integrated model and strong market access position resulted in Suncor capturing global-based pricing on volumes equivalent to 97% of its upstream production in 2014, compared to 88% in 2013.

Oil Sands operations grows production with strong Firebag performance.

- Oil Sands operations increased annual production in 2014 by 8%.

- Production levels at Firebag have increased by more than 65% since 2012, and the facility attained rates above nameplate capacity of 180,000 bbls/d in the fourth quarter of 2014.

- Strong infill well performance and optimized reservoir management strategies contributed to a record low steam-to-oil ratio (SOR) of 2.8 at Firebag for the year.

- Suncor achieved first oil at the MacKay River debottleneck project, providing low-cost capacity growth.

- Suncor continues to advance Oil Sands Base projects that are directed towards operational efficiencies and improved reliability.

A continued focus on operational excellence and improved reliability.

- Demonstrated reliability and continuous improvements of the company's refining facilities resulted in 93% overall refinery utilization despite planned maintenance. Modifications to the Montreal refinery were completed in 2014 and are expected to improve overall production yields.

- The company continues to focus on improving facility utilization and workforce productivity, including In Situ debottlenecks and increasing upgrader reliability to target a 90% utilization rate of 315,000 bbls/d by 2017.

(1) Cash operating costs per barrel is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

3. FINANCIAL INFORMATION

Net Earnings

Suncor's net earnings for 2014 were $2.699 billion, compared to $3.911 billion in 2013. Net earnings were impacted by the same factors that influenced operating earnings, which are described below. Other items affecting net earnings in 2014 and 2013 included:

- The after-tax unrealized foreign exchange loss on the revaluation of U.S. dollar denominated debt was $722 million in 2014, compared with a loss of $521 million in 2013.
- In 2014, Total E&P Canada Ltd. (Total E&P), the operator of the Joslyn mining project, together with Suncor and the other co-owners of the project, agreed to scale back certain development activities in order to focus on engineering studies to further optimize the Joslyn project development plan. As a result of Suncor's assessment of expected future net cash flows and the uncertainty of the project, including the timing of the development plans, Suncor recorded an after-tax impairment charge of $718 million.
- In the second quarter of 2014, as a result of the shut-in of production in Libya due to the closure of certain export terminals and the company's production forecasts for the remaining contract terms, the company performed an impairment test on its Libyan assets, resulting in an after-tax impairment charge of $297 million.
- The company recorded after-tax impairment charges of $223 million in 2014 in the Oil Sands segment following a review of certain assets that no longer fit with Suncor's growth strategies and which could not be repurposed or otherwise deployed. These assets included a pipeline and related compressor, as well as steam generator components.
- In 2014, the company recorded an after-tax gain of $61 million relating to the sale of its Wilson Creek oil and gas assets in E&P Canada.
- Suncor recorded a current income tax and associated interest charge of $54 million in 2014 related to the timing of tax depreciation deductions taken on certain capital expenditures in the Oil Sands segment in a prior period.
- In 2014, the company recorded after-tax earnings of $32 million for a 1.2 million barrels of oil reserves redetermination related to an interest in a Norwegian asset that Suncor previously owned.
- The fourth quarter of 2013 included after-tax impairment charges of $563 million in the E&P segment against its assets in Syria, Libya and E&P Canada. Concurrent with the impairment of its Syrian assets, the company recognized after-tax risk mitigation proceeds of $223 million, previously recorded as a long-term provision.
- Suncor recorded an after-tax charge of $58 million in 2013 as a result of not proceeding with the Voyageur upgrader project.
- In 2013, Suncor recorded an after-tax gain of $130 million relating to the sale of the company's conventional natural gas business in E&P Canada.

Operating Earnings

Consolidated Operating Earnings Reconciliation[1]

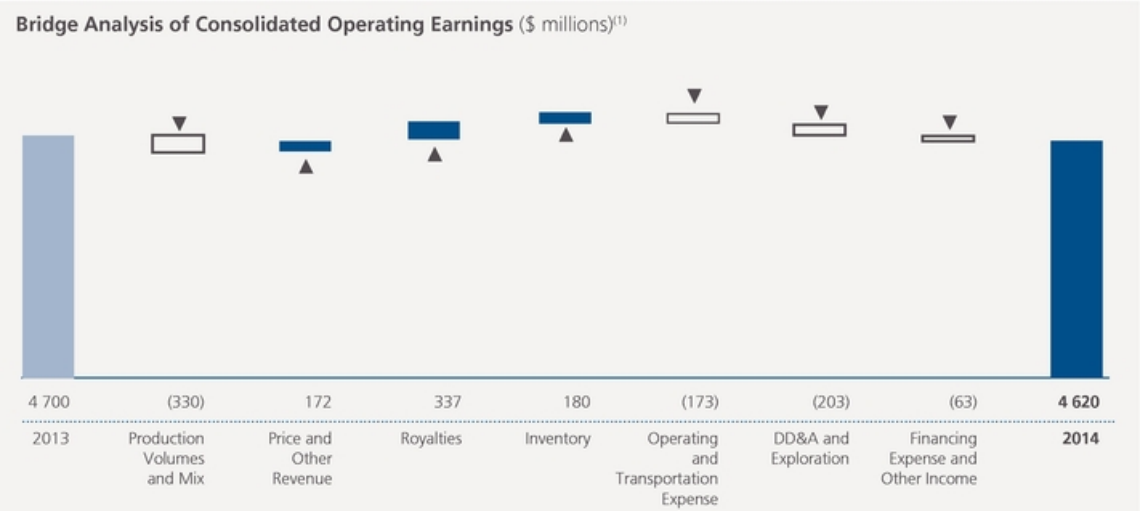
Year ended December 31 ($ millions)	2014	2013	2012
Net earnings as reported	**2 699**	3 911	2 740
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**722**	521	(157)
Impairments net of reversals and provisions[2]	**1 238**	563	689
Recognition of risk mitigation proceeds	**—**	(223)	—
Net impact of not proceeding with the Voyageur upgrader project[3]	**—**	58	1 487
Gain on significant disposals	**(61)**	(130)	—
Impact of income tax adjustments on deferred income taxes[4]	**54**	—	88
Reserves redetermination	**(32)**	—	—
Operating earnings[1]	**4 620**	4 700	4 847

(1) Non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

(2) In 2012, the company recorded an after-tax impairment of $517 million charged against assets in Syria, and after-tax charges of $172 million in E&P Canada including impairments against assets and a provision for estimated future commitments relating to unutilized pipeline capacity.

(3) In 2012, the company recorded an after-tax impairment charge of $1.487 billion against the Voyageur upgrader project.

(4) In 2012, the Province of Ontario approved a budget that froze the general corporate income tax rate at 11.5%, instead of the planned reduction to 10% by 2014. As a result, the company adjusted its deferred income tax balances, leading to a charge to net earnings of $88 million.



(1) For an explanation of the construction of this bridge analysis, see the Advisories – Non-GAAP Financial Measures section of this MD&A.

Suncor's consolidated operating earnings for 2014 were $4.620 billion, compared to $4.700 billion in 2013. The decrease was primarily due to lower operating earnings from the E&P segment as a result of volume decreases at Buzzard, the sale of the company's conventional natural gas business which took place in 2013 and lower contributions from Libya. In addition, the Refining and Marketing segment earnings decreased due to the lower downstream pricing environment. These factors were partially offset by higher production from the Oil Sands segment and higher price realizations for Oil Sands sales which benefited from favourable foreign exchange rates.

Cash Flow from Operations

Consolidated cash flow from operations for 2014 was $9.058 billion, compared to $9.412 billion in 2013. Cash flow from operations decreased primarily due to lower production and price realizations in E&P and lower margins in Refining and Marketing as well as the impacts of settling trading positions in Energy Trading, partially offset by higher production and average price realizations from Oil Sands operations.

Results for 2013 compared with 2012

Net earnings for 2013 were $3.911 billion, compared to $2.740 billion in 2012. The increase in net earnings was mainly due to the same factors impacting operating earnings and by the operating earnings adjustments described above.

Operating earnings for 2013 were $4.700 billion, compared to $4.847 billion in 2012. The decrease in operating earnings was mainly due to increased operating costs in Oil Sands as a result of increased production, higher DD&A and exploration expenses due to a larger asset base, lower refining margins, and reduced production in E&P as a result of the sale of the company's conventional natural gas business and the shut-in of production in Libya in 2013. These were partially offset by higher price realizations for upstream production, lower royalties due to the impact of lower production from Libya, and higher upstream production reflecting record production in Oil Sands.

Consolidated cash flow from operations for 2013 was $9.412 billion, compared to $9.733 billion in 2012. Cash flow from operations decreased primarily due to incremental current income tax expense related to the company's Canadian operations recorded in 2013 and higher operating expenses, partially offset by higher production volumes and higher price realizations.

Business Environment

Commodity prices, refining crack spreads and foreign exchange rates are important factors that affect the results of Suncor's operations.

Year ended December 31	**2014**	2013	2012
WTI crude oil at Cushing (US$/bbl)	**93.00**	97.95	94.20
ICE Brent crude oil at Sullom Voe (US$/bbl)	**99.50**	108.75	111.70
Dated Brent/Maya FOB price differential (US$/bbl)	**13.70**	11.65	12.15
MSW at Edmonton (Cdn$/bbl)	**86.10**	93.90	86.60
WCS at Hardisty (US$/bbl)	**73.60**	72.75	73.15
Light/heavy differential for WTI at Cushing less WCS at Hardisty (US$/bbl)	**19.40**	25.20	21.05
Condensate at Edmonton (US$/bbl)	**92.95**	101.70	100.75
Natural gas (Alberta spot) at AECO (Cdn$/mcf)	**4.50**	3.15	2.40
Alberta Power Pool Price	**49.65**	79.95	64.29
New York Harbor 3-2-1 crack (1) (US$/bbl)	**19.65**	23.90	32.90
Chicago 3-2-1 crack (1) (US$/bbl)	**17.40**	21.40	27.40
Portland 3-2-1 crack (1) (US$/bbl)	**20.15**	24.00	33.40
Gulf Coast 3-2-1 crack (1) (US$/bbl)	**16.50**	20.55	29.00
Exchange rate (US$/Cdn$)	**0.91**	0.97	1.00
Exchange rate (end of period) (US$/Cdn$)	**0.86**	0.94	1.01

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Suncor's sweet SCO price realizations are influenced primarily by the price of WTI at Cushing and by the supply and demand of sweet SCO from Western Canada. WTI decreased to US$93.00/bbl in 2014, compared to US$97.95/bbl in 2013.

Suncor produces a specific grade of sour SCO, the price realizations for which are influenced by various crude benchmarks including, but not limited to: MSW at Edmonton and WCS at Hardisty, and which can also be affected by prices negotiated for spot sales. Prices for WCS at Hardisty increased in 2014 compared to 2013, resulting in slightly higher realizations for sour SCO.

Bitumen production that Suncor does not upgrade is blended with diluent to facilitate delivery on pipeline systems. Net bitumen price realizations are therefore influenced by both prices for Canadian heavy crude oil (WCS at Hardisty is a common reference) and prices for diluent (Condensate at Edmonton and SCO). Bitumen price realizations can also be affected by bitumen quality and spot sales. Average prices for WCS at Hardisty increased slightly in 2014 compared to 2013 while Condensate at Edmonton decreased in comparison to 2013, resulting in higher realizations for bitumen.

Suncor's price realizations for production from East Coast Canada and E&P International assets are influenced primarily by the price for Brent crude. Brent crude pricing decreased over the prior year and averaged US$99.50/bbl in 2014, compared to US$108.75/bbl in 2013.

Suncor's price realizations for E&P Canada natural gas production are primarily referenced to Alberta spot at AECO. Natural gas is also used in the company's Oil Sands and Refining operations. The average AECO benchmark increased to $4.50/mcf in 2014, from $3.15/mcf in 2013.

Suncor's refining margins are influenced by 3-2-1 crack spreads, which are industry indicators approximating the gross margin on a barrel of crude oil that is refined to produce gasoline and distillate, and by light/heavy and light/sour crude differentials. More complex refineries can earn greater margins by processing less expensive, heavier crudes. Crack spreads do not necessarily reflect the margins of a specific refinery. Crack spreads are based on current crude feedstock prices whereas actual refining margins are based on first-in, first-out inventory accounting (FIFO), where a delay exists between the time that feedstock is purchased and when it is processed and sold to a third party. Specific refinery margins are further impacted by actual crude purchase costs, refinery configuration and refined products sales markets unique to that refinery. Average market crack spreads decreased in 2014, primarily influenced by the narrowing WTI to Brent, resulting in a negative impact to refining margins.

Excess electricity produced in Suncor's In Situ business is sold to the Alberta Electric System Operator (AESO), with the proceeds netted against the cash operating cost per barrel metric. The Alberta power pool price decreased to an average of $49.65/MWh in 2014 from $79.95/MWh in the prior year.

The majority of Suncor's revenues from the sale of oil and natural gas commodities are based on prices that are determined by or referenced to U.S. dollar benchmark prices. The majority of Suncor's expenditures are realized in Canadian dollars. A decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of commodities. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease revenue received from the sale of commodities. In 2014, the Canadian dollar weakened in relation to the U.S. dollar as the average exchange rate decreased to 0.91 from 0.97, which had a positive impact on price realizations for the company in 2014.

Conversely, many of Suncor's assets and liabilities, notably most of the company's debt, are denominated in U.S. dollars and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. A decrease in the value of the Canadian dollar relative to the U.S. dollar from the previous balance sheet date increases the amount of Canadian dollars required to settle U.S. dollar denominated obligations.

Economic Sensitivities[1][2]

The following table illustrates the estimated effects that changes in certain factors would have had on 2014 net earnings and cash flow from operations if the listed changes had occurred.

(Estimated change, in $ millions)	Net Earnings	Cash Flow From Operations
Crude oil +US$1.00/bbl	115	115
Natural gas +Cdn$0.10/mcf	(15)	(15)
Light/heavy differential +US$1.00/bbl	15	15
3-2-1 crack spreads +US$1.00/bbl	120	120
Foreign exchange +$0.01 US$/Cdn$[3] related to operating activities	(145)	(145)
Foreign exchange on U.S. denominated debt +$0.01 US$/Cdn$[3]	95	—

(1) Each line item in this table shows the effects of a change in that variable only, with other variables being held consistent.

(2) Changes for a variable imply that all such similar variables are impacted, such that Suncor's average price realizations increase uniformly. For instance, "Crude oil +US$1.00/bbl" implies that price realizations influenced by WTI, Brent, SCO, WCS, par crude at Edmonton and condensate all increase by US$1.00/bbl.

(3) The difference between estimates for net earnings and cash flow from operations are due primarily to the revaluation of U.S. dollar denominated debt that is included within net earnings but not within cash flow from operations.

4. SEGMENT RESULTS AND ANALYSIS

Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in the Athabasca oil sands of northeast Alberta, recovers bitumen from mining and in situ operations and either upgrades this production into SCO for refinery feedstock and diesel fuel, or blends the bitumen with diluent for direct sale to market. The Oil Sands segment includes:

- **Oil Sands operations** refer to Suncor's wholly owned and operated mining, extraction, upgrading, in situ and related logistics and storage assets in the Athabasca oil sands region. Oil Sands operations consist of:

    - **Oil Sands Base** operations include the Millennium and North Steepbank mining and extraction operations, 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 Suncor's Tailings Reduction Operations process (TRO_{TM}) assets.

    - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities, cogeneration units and hot bitumen infrastructure, including insulated pipelines, diluent import capabilities and a cooling and blending facility, and related storage assets. In Situ production is either upgraded by Oil Sands Base, or blended with diluent and marketed directly to customers.

- **Oil Sands ventures** operations include Suncor's 40.8% interest in the Fort Hills mining project, where Suncor is the operator, and its 36.75% interest in the Joslyn North mining project, where Total E&P is the operator. The company also holds a 12.0% interest in the Syncrude oil sands mining and upgrading operation.

EXPLORATION AND PRODUCTION

Suncor's Exploration and Production (E&P) segment consists of offshore operations off the east coast of Canada and in the North Sea, and onshore assets in North America, Libya and Syria.

- **E&P Canada** operations include Suncor's 37.675% working interest in Terra Nova, which Suncor operates. Suncor also holds a 20.0% 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. Suncor also holds interests in several exploration licences offshore Newfoundland and Labrador and Nova Scotia. E&P Canada also includes Suncor's working interests in unconventional natural gas properties in northeast B.C.

- **E&P International** operations include Suncor's 29.89% working interest in Buzzard and its 26.69% interest in Golden Eagle. Both projects are located in the U.K. sector of the North Sea and are operated by another company. Suncor also holds interests in several exploration licences offshore the U.K. and Norway. Suncor owns, pursuant to Exploration and Production Sharing Agreements (EPSAs), working interests in the exploration and development of oilfields in the Sirte Basin in Libya. Suncor also owns, pursuant to a Production Sharing Contract (PSC), an interest in the Ebla gas development in the Ash Shaer and Cherrife areas in Syria. Suncor's operations in Syria were suspended indefinitely in 2011, due to political unrest in the country.

REFINING AND MARKETING

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

- **Refining and Supply** operations refine crude oil and intermediate feedstock into a broad range of petroleum and petrochemical products. Refining and Supply consists of:

    - **Eastern North America** operations which include a refinery located in Montreal, Quebec, a refinery located in Sarnia, Ontario, and a lubricants business located in Mississauga, Ontario that manufactures and blends products which are marketed worldwide.
    - **Western North America** operations which include refineries located in Edmonton, Alberta and Commerce City, Colorado.
    - Other Refining and Supply assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the U.S.

- **Downstream Marketing** operations sell refined petroleum products to retail, commercial and industrial customers through a combination of company-owned, Petro-Canada 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. Lubricant products are marketed worldwide through company-operated locations and distributor networks.

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 marketing, supply and trading activities, and other activities not directly attributable to any other operating segment.

- **Renewable Energy** interests include seven wind facilities across Canada, including Adelaide which is the most recent addition to the portfolio, and the St. Clair ethanol plant in Ontario. An eighth wind farm, Cedar Point, is planned to commence commercial operations later in 2015.
- **Energy Trading** activities primarily involve the marketing, supply and trading of crude oil, natural gas, power and byproducts, and the use of midstream infrastructure and financial derivatives to optimize related trading strategies.
- **Corporate** activities include 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 product between the company's segments and insurance for a portion of the company's operations by the **Corporate** captive insurance entity.

OIL SANDS

2014 Highlights

- Oil Sands operations increased production by 8% in 2014 compared to 2013, driven primarily by increased Firebag production.
- Record low SOR at Firebag of 2.8 for 2014, primarily due to optimized reservoir management strategies and strong infill well performance.
- The company's continued focus on cost management, combined with increased production, enabled Suncor to decrease its cash operating costs per barrel by $3.20/bbl to $33.80/bbl in 2014, compared to $37.00/bbl the prior year.
- First oil was achieved from wells associated with the MacKay River debottleneck project.
- Fort Hills construction continued to ramp up with detailed engineering work approximately 65% complete and construction approximately 20% complete by the end of the fourth quarter. First oil is expected as early as the fourth quarter of 2017.
- A decision was made with the other co-owners of the Joslyn mining project to scale back certain development activities at the Joslyn mining project, reinforcing Suncor's disciplined approach to capital allocation and commitment to driving higher returns.
- Suncor maximized the value of Oil Sands production, through additional crude by rail shipments to the Montreal refinery and increased sales to the U.S. Gulf Coast during favourable market conditions.

Strategy and Investment Update

Oil Sands operations has established a large physical asset base providing the opportunity for production growth through low-cost debottlenecks, expansions and increased reliability. Hot bitumen infrastructure has added operational flexibility by enabling the transportation of hot bitumen from Firebag to Suncor's cooling and blending facilities, which can then be sold directly to market without the need for upgrading.

Suncor continues to work closely with the Fort Hills mining project co-owners on engineering, procurement and construction activities. As operator of the Fort Hills project, Suncor is developing the mine using traditional open-pit truck and shovel techniques, and solvent-based extraction technology that will allow the mine to produce a bitumen product that can be sold directly to the market.

Sustaining capital for Oil Sands operations continues to focus on safe, reliable and sustainable operations. The company's operational excellence initiatives continue to target improving facility utilization and workforce productivity, including a focus on upgrader reliability, that are expected to achieve steady production growth while reducing operating costs.

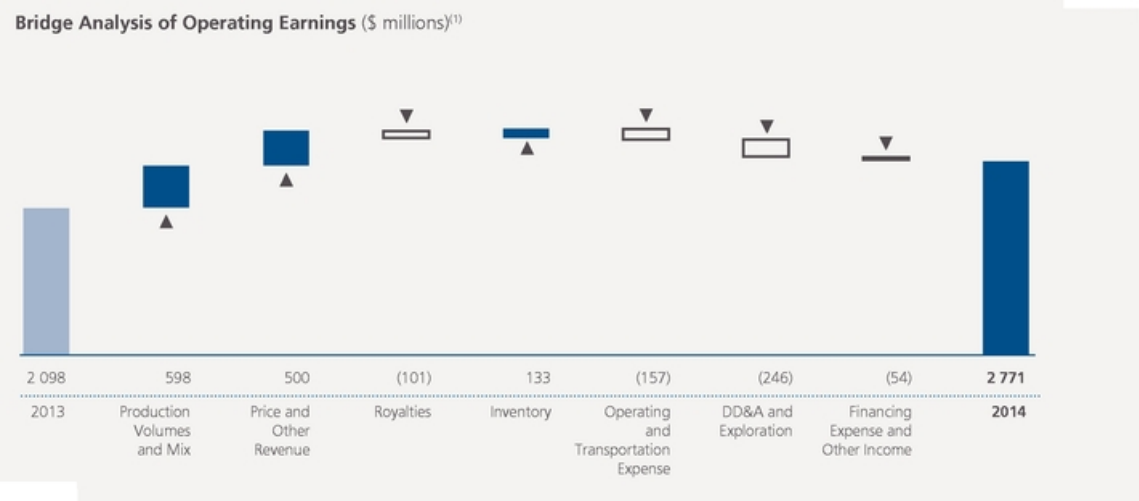
The company also continues to progress debottlenecking and infill drilling programs at both Firebag and MacKay River to support steady production growth and sustainment.

Growth capital for Oil Sands operations in 2015 is expected to include the construction of on-site midstream assets that will be used to support production, including hot bitumen cooling and blending facilities, and related storage assets. In response to the current crude price environment, a sanction decision on the MacKay River expansion project has been deferred.

Financial Highlights

Year ended December 31 ($ millions)	2014	2013	2012
Gross revenues	**14 561**	13 089	11 502
Less: Royalties	**(982)**	(859)	(684)
Operating revenues, net of royalties	**13 579**	12 230	10 818
Net earnings	**1 776**	2 040	468
Adjusted for:			
Net impact of not proceeding with the Voyageur upgrader project	**—**	58	1 487
Impairments	**941**	—	—
Impact of income tax adjustments on deferred income taxes	**54**	—	70
Operating earnings[1]	**2 771**	2 098	2 025
Oil Sands operations	**2 696**	1 870	1 807
Oil Sands ventures	**75**	228	218
Cash flow from operations[1]	**5 400**	4 556	4 407

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.



(1) For an explanation of the construction of this bridge analysis, see the Advisories – Non-GAAP Financial Measures section of this MD&A.

Oil Sands operations contributed $2.696 billion to operating earnings in 2014, while Oil Sands ventures contributed $75 million. Operating earnings for Oil Sands operations increased compared to the prior year primarily due to higher production volumes and prices, partially offset by higher DD&A, operating and royalty expenses.

Operating earnings for Oil Sands ventures decreased primarily due to lower production and higher operating expenses related to planned and unplanned maintenance at Syncrude.

Cash flow from operations for the Oil Sands segment was $5.400 billion in 2014, compared to $4.556 billion in 2013. The increase was primarily due to higher production volumes and prices, partially offset by higher royalty and operating and transportation expenses.

Production Volumes[1]

Year ended December 31 (mbbls/d)	**2014**	2013	2012
Upgraded product (SCO)	**289.1**	282.6	276.7
Non-upgraded bitumen	**101.8**	77.9	48.1
Oil Sands operations	**390.9**	360.5	324.8
Oil Sands ventures – Syncrude	**31.0**	32.0	34.4
Total	**421.9**	392.5	359.2

(1) Bitumen from Oil Sands Base operations is upgraded, while bitumen from In Situ operations is upgraded or sold directly to customers. Yields of SCO from Suncor's upgrading processes are approximately 79% of bitumen feedstock input.

The increase in production in Oil Sands operations in 2014, compared to 2013, was primarily due to increased production at Firebag following the commissioning of hot bitumen infrastructure assets that was completed in the third quarter of 2013, and lower planned maintenance in the current year as the prior year included an Upgrader 1 turnaround. Current year production was impacted by planned coker maintenance in the spring and fall of 2014, unplanned maintenance in upgrading and extraction during the third and fourth quarters of 2014, and a weather-related site-wide power outage in the third quarter of 2014.

Bitumen Production from Operations

Year ended December 31	**2014**	2013	2012
Oil Sands Base			
Bitumen Production (mbbls/d)	**274.4**	269.8	266.2
Bitumen ore mined (thousands of tonnes per day)	**408.5**	413.6	412.3
Bitumen ore grade quality (bbls/tonne)	**0.67**	0.65	0.65
In Situ bitumen production (mbbls/d)			
Firebag	**172.0**	143.4	104.0
MacKay River	**27.0**	28.5	27.0
Total In Situ production	**199.0**	171.9	131.0
In Situ steam-to-oil ratio			
Firebag	**2.8**	3.3	3.4
MacKay River	**2.9**	2.6	2.4

Bitumen production from Oil Sands Base operations increased to an average of 274,400 bbls/d in 2014, compared to 269,800 bbls/d in 2013, primarily due to the commissioning of the hot bitumen infrastructure in 2013, which resulted in increased takeaway capacity and unlocked previously constrained production in mining. However, this was partially offset by unplanned extraction, upgrading, and utilities maintenance in the third and fourth quarters of 2014. In 2013, bitumen production was reduced in the second quarter of 2013 as the company scaled back mine production to coincide with limited upgrader availability during the Upgrader 1 turnaround.

Bitumen production from In Situ operations averaged 199,000 bbls/d in 2014, increasing from 171,900 bbls/d in 2013 primarily due to increased Firebag production. Production at MacKay River averaged 27,000 bbls/d in 2014, slightly below 28,500 bbls/d in 2013, primarily due to unplanned maintenance completed in the first quarter of 2014, partially offset by additional production from the MacKay River debottleneck project.

Firebag attained a record low SOR of 2.8 in 2014, down from 3.3 in 2013, primarily due to strong infill well performance and optimized reservoir management strategies. The SOR at MacKay River increased to 2.9 from 2.6 in 2013, primarily due to early steam requirements for recently commissioned wells associated with the MacKay River debottleneck project.

Suncor's share of Syncrude production and sales volumes averaged 31,000 bbls/d in 2014, compared to 32,000 bbls/d in 2013. Production in 2014 was impacted by unplanned maintenance on one of its three cokers in the second quarter of 2014 and increased planned maintenance in 2014.

Sales Volumes and Mix

Year ended December 31	**2014**	2013	2012
Oil Sands sales volumes (mbbls/d)			
Sweet SCO	**99.7**	91.5	93.8
Diesel	**30.7**	23.5	24.5
Sour SCO	**158.9**	166.0	161.1
Upgraded product (SCO)	**289.3**	281.0	279.4
Non-upgraded bitumen	**101.4**	76.0	44.5
	390.7	357.0	323.9

Sales volumes for Oil Sands operations increased to 390,700 bbls/d in 2014, compared to 357,000 bbls/d in 2013, reflecting the same factors that led to the overall increase in production volumes. The sales mix improved in 2014, compared to 2013, primarily due to lower planned and unplanned maintenance in the current year. The sales mix in 2013 was impacted by planned maintenance on Upgrader 1.

Sales volumes of non-upgraded bitumen increased in 2014, compared to 2013, mainly due to higher production at Firebag and the increased operational flexibility provided by

the hot bitumen infrastructure commissioned in the third quarter of 2013.

Inventory

The inventory variance factor increased operating earnings primarily due to a smaller inventory build in 2014 relative to the inventory build in 2013, which was related to the addition of new infrastructure to the company's storage and logistics network.

Price Realizations

Year ended December 31 Net of transportation costs, but before royalties ($/bbl)	**2014**	2013	2012
Oil Sands operations			
Sweet SCO and diesel	**109.02**	104.22	96.95
Sour SCO and non-upgraded bitumen	**76.66**	72.67	72.93
Crude sales basket (all products)	**87.46**	82.83	81.69
Crude sales basket, relative to WTI	**(15.28)**	(18.09)	(12.44)
Oil Sands ventures			
Syncrude – Sweet SCO	**99.32**	99.82	92.69
Syncrude, relative to WTI	**(3.42)**	(1.10)	(1.50)

Sweet SCO and diesel price realizations were positively impacted by favourable exchange rates, partially offset by the decrease in the WTI benchmark price. Sour SCO and bitumen prices increased in 2014 primarily due to the higher WCS benchmark price and favourable foreign exchange rates. These increases for both sweet and sour SCO resulted in average price realizations for Oil Sands operations of $87.46/bbl in 2014, compared to $82.83/bbl in 2013.

Suncor's average price realization for Syncrude sales in 2014 of $99.32/bbl was comparable to the average price realization of $99.82/bbl in 2013, as the impacts of the weaker Canadian dollar in 2014 partially offset the decrease in WTI benchmark prices.

Royalties

Royalties were higher in 2014 relative to 2013, primarily due to higher production and slightly higher prices for WCS that influenced the company's regulated bitumen valuation methodology.

Expenses and Other Factors

Operating expenses for 2014 were higher relative to 2013. Factors contributing to the change in operating expenses included:

- Non-production costs were higher in 2014 compared to 2013, primarily due to higher prices for feedstock costs used in the secondary upgrading process, higher costs associated with research and future growth activities, as well as higher expenses related to a gas swap arrangement involving a third-party processor.
- Operating expenses at Syncrude were higher for 2014 than 2013 as a result of higher natural gas prices and higher maintenance expenditures.
- A decrease in cash operating costs for Oil Sands operations. See the Cash Operating Cost Reconciliation for further details.

Transportation expense increased in 2014, relative to 2013, primarily due to increased sales volumes, including incremental costs associated with increased pipeline access.

DD&A expense for 2014 was higher than 2013, mainly due to a larger asset base as a result of Firebag well pads and additional infill wells commissioned in 2014, and the commissioning of associated hot bitumen assets in the latter half of 2013.

Cash Operating Costs Reconciliation[(1)]

Year ended December 31	**2014**	2013	2012
Operating, selling and general expense (OS&G)	**6 042**	5 852	5 422
Syncrude OS&G	**(593)**	(536)	(513)
Non-production costs[(2)]	**(442)**	(282)	(385)

Other[3]	**(187)**	(165)	(129)
Oil Sands cash operating costs ($ millions)	**4 820**	4 869	4 395
Oil Sands cash operating costs ($/bbl)	**33.80**	37.00	37.05

(1) Cash operating costs and cash operating costs per barrel are non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this document.

(2) Significant non-production costs include share-based compensation adjustments, research, the expense recorded as part of a gas swap arrangement involving a third-party processor and feedstock costs for natural gas used to create hydrogen for secondary upgrading processes.

(3) Other includes the impacts of changes in inventory valuation and operating revenues associated with excess capacity, primarily power from cogeneration units that was deducted from total cash operating costs.

Oil Sands cash operating costs per barrel averaged $33.80/bbl in 2014, compared to $37.00/bbl in 2013, primarily due to higher production volumes and lower cash

operating costs in 2014. Total cash operating costs decreased in 2014, primarily due to lower operating and maintenance costs in upgrading and mining, partially offset by higher natural gas costs due to higher In Situ consumption and prices.

Planned Maintenance

There are no major turnarounds scheduled for 2015. The company plans to complete routine maintenance on two coker units throughout the year. The impact of this maintenance has been reflected in the company's 2015 guidance.

EXPLORATION AND PRODUCTION

2014 Highlights

- Significant growth projects advanced through major milestones in 2014, including the achievement of first oil at the Golden Eagle project in the fourth quarter. The gravity-based structure at the Hebron project was successfully moved from dry dock into its deepwater construction site.
- Suncor completed the sale of the Wilson Creek assets in central Alberta for $168.5 million, before closing adjustments and other closing costs, highlighting Suncor's continued focus on assets that are aligned with the company's long-term strategy.
- The company signed a farm-in agreement with Shell Canada to acquire a 20% interest in a deepwater exploration opportunity in the Shelburne Basin offshore Nova Scotia. Through this agreement, Suncor has committed to participate in two exploration wells commencing in the second half of 2015.
- Suncor was a successful joint bidder with ExxonMobil Canada for exploration rights off the coast of Newfoundland (30% working interest). The bid comes with an exploration commitment over the next six to nine years on an emerging oil play.

Strategy and Investment Update

The Exploration and Production segment focuses on high-margin projects that deliver significant returns, cash flow and long-term value. Suncor is currently evaluating exploration and development opportunities off the east coast of Canada, Norway and in the U.K. North Sea to provide diverse and lower cost conventional production. Building on the major milestones reached in 2014, drilling activities are expected to continue on the Golden Eagle project through 2015, and the Hebron project remains on target for first oil in 2017.

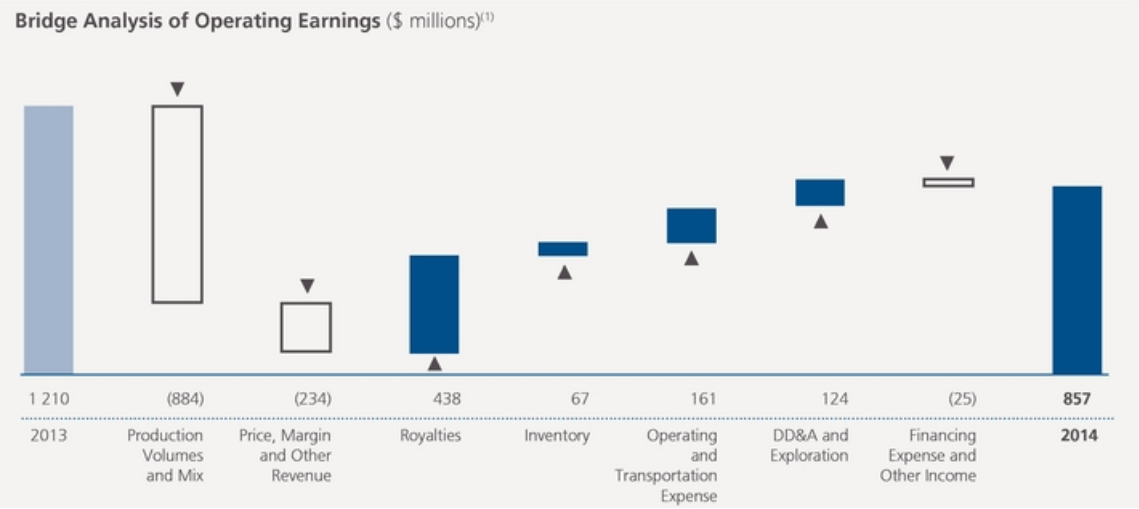
The company has multiple field extension projects underway which leverage existing facilities and infrastructure. The HSEU project commenced water injection in late 2014 with production expected to ramp up in the last half of 2015. Following the completion of subsea facilities for the South White Rose Extension (SWRX), drilling is expected to continue in 2015, with first oil anticipated in the second quarter of 2015. The HSEU and SWRX projects are expected to provide incremental production and extend the productive life of the existing fields. The co-owners of the White Rose Extension Project (WREP) have agreed to defer the project sanction decision in light of the current lower crude price environment.

Suncor has a portfolio of 27 Norway and U.K. North Sea licences for possible exploration opportunities. Discoveries currently under appraisal in Norway include the operated Beta project, where a fourth appraisal well is planned in 2015, and the non-operated Butch project, where further evaluation activities will continue in 2015.

Financial Highlights

Year ended December 31 ($ millions)	2014	2013	2012
Gross revenues	**4 715**	6 363	6 476
Less: Royalties	**(672)**	(1 146)	(1 631)
Operating revenues, net of royalties	**4 043**	5 217	4 845
Net earnings	**653**	1 000	138
Adjusted for:			
Impairments (net of reversals) and provisions	**297**	563	689
Recognition of risk mitigation proceeds	**—**	(223)	—
Gain on significant disposals	**(61)**	(130)	—
Impact of income tax rate adjustments on deferred income taxes	**—**	—	23
Reserves redetermination	**(32)**	—	—
Operating Earnings[1]	**857**	1 210	850
E&P Canada	**502**	643	312
E&P International	**355**	567	538
Cash flow from operations[1]	**1 909**	2 316	2 227

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.



(1) For an explanation of the construction of this bridge analysis, see the Advisories – Non-GAAP Financial Measures section of this MD&A.

Operating earnings in 2014 for E&P Canada were $502 million, compared to $643 million for 2013, and were lower primarily due to lower production as a result of the sale of the conventional natural gas business in 2013, and lower oil price realizations in 2014. Operating earnings for E&P International were $355 million for 2014, compared to $567 million for 2013, and were lower primarily due to decreased production at Buzzard, lower price realizations and lower contributions from Libya.

Cash flow from operations was $1.909 billion in 2014, compared to $2.316 billion in 2013, and decreased primarily due to lower production volumes and lower price realizations, partially offset by lower operating expenses as a result of the sale of the conventional natural gas business.

Production Volumes

Year ended December 31	**2014**	2013	2012
E&P Canada			
Terra Nova (mbbls/d)	**17.3**	14.2	8.8
Hibernia (mbbls/d)	**23.1**	27.1	26.1
White Rose (mbbls/d)	**14.6**	14.9	11.6
North America Onshore (mboe/d)	**3.6**	37.3	53.9
	58.6	93.5	100.4
E&P International			
Buzzard (mboe/d)	**47.1**	55.8	48.0
Golden Eagle (mboe/d)	**0.6**	—	—
Libya (mbbls/d)	**6.7**	20.6	41.5
	54.4	76.4	89.5
Total Production (mboe/d)	**113.0**	169.9	189.9
Production Mix (liquids/gas) (%)	**97/3**	80/20	74/26

E&P Canada production averaged 58,600 boe/d in 2014, compared to 93,500 boe/d in 2013.

- Production from Terra Nova averaged 17,300 bbls/d in 2014, compared to 14,200 bbls/d in 2013. In 2014, production was impacted by a four-week planned maintenance program, while 2013 was impacted by a ten-week off-station maintenance program to repair a mooring chain and perform preventive maintenance on the remaining eight chains.
- Production from Hibernia averaged 23,100 bbls/d in 2014, compared to 27,100 bbls/d in 2013. Production decreased in 2014 primarily due to natural declines from older wells.
- Production from White Rose averaged 14,600 bbls/d in 2014, consistent with 2013 production.
- Production from North America Onshore averaged 3,600 boe/d in 2014, compared to 37,300 boe/d in 2013. Production decreased primarily due to the sale of the conventional natural gas business in September 2013.

E&P International production averaged 54,400 boe/d in 2014, compared to 76,400 boe/d in 2013.

- Production from Buzzard averaged 47,100 boe/d in 2014, compared to 55,800 boe/d in 2013. Production decreased due to higher maintenance activity in 2014 and natural declines.
- Production from Golden Eagle averaged 600 boe/d in 2014, as first oil was achieved in the fourth quarter of 2014 and production continued to ramp up at the end of 2014.
- Production from Libya averaged 6,700 bbls/d in 2014, compared to 20,600 bbls/d in 2013. Production was lower in 2014 as operations have been substantially shut-in since July 2013 due to political unrest in the country. Production started to ramp up in the latter half of 2014 after the Libya National Oil Company (NOC) removed force majeure in July 2014 on oil exports from terminals, used by Suncor. However, further political unrest in December 2014 has resulted in the NOC declaring force majeure on oil exports from these terminals once again resulting in the company's operations being substantially shut in at year end. The timing of a return to normal production levels remains uncertain.

Price Realizations

Twelve months ended December 31 **Net of transportation costs, but before royalties**	**2014**	2013	2012
Exploration and Production			
E&P Canada – Crude oil and natural gas liquids ($/bbl)	**105.98**	109.71	108.36
E&P Canada – Natural gas ($/mcfe)	**4.49**	3.42	2.17

E&P International ($/boe)	**104.12**	107.57	108.22
E&P average price ($/boe)	**103.05**	91.44	84.05

Average price realizations for crude oil from E&P Canada and E&P International were lower than 2013, consistent with the decrease in benchmark prices for Brent crude in the last half of 2014, partially offset by favourable foreign exchange rates.

Royalties

Royalties were lower in 2014, compared with 2013, primarily due to lower production from Libya and North America Onshore.

Inventory

The inventory variance factor increased operating earnings primarily due to a smaller inventory build in 2014 relative to the inventory build in 2013.

Expenses and Other Factors

Operating expenses were lower in 2014 than in 2013, primarily due to the sale of the conventional natural gas assets and lower share-based compensation expense in 2014.

DD&A and exploration expenses were lower in 2014, primarily due to lower production in North America

Onshore and Libya, and lower depletion rates on the company's east coast Canada assets. Exploration expenses were higher in 2014 as a result of seismic purchases in Norway and off the East Coast of Canada. During 2014, Suncor expensed $104 million in exploration activities ($36 million after-tax) related to wells in Norway and the U.K., compared to $82 million in exploration expenditures ($46 million after-tax) in 2013, primarily related to wells in the U.K. and Libya.

Financing expense and other income increased in 2014 relative to 2013, primarily due to foreign exchange losses in E&P International, partially offset by lower accretion on the decommissioning and restoration provision in North America Onshore following the sale of the company's conventional natural gas assets.

Other Items

Sale of Oil and Natural Gas Assets

On September 30, 2014, Suncor completed the sale of its Wilson Creek oil and gas assets in central Alberta for $168.5 million before closing adjustments and other closing costs. The sale had an effective date of July 1, 2014, and resulted in an after-tax gain on the sale of $61 million.

On September 26, 2013, Suncor completed the sale of its conventional natural gas business in Western Canada for proceeds of $1 billion, before closing adjustments and other closing costs. The sale had an effective date of January 1, 2013, and resulted in an after-tax gain on the sale of $130 million.

Planned Maintenance of Operated Assets

A planned ten-week maintenance event at Terra Nova has been scheduled to commence in the second quarter of 2015. The impact of this maintenance has been reflected in the company's 2015 guidance.

REFINING AND MARKETING

2014 Highlights

- The Refining and Marketing segment continues to be a key component of the company's integrated model and generated $1.692 billion in operating earnings in 2014.
- Strong refinery utilizations allowed Suncor to reduce the impacts of a decreasing upstream crude price environment by optimizing the profit realized on a portion of Suncor's upstream production.
- Suncor lowered feedstock costs at the Montreal refinery through increased rail shipments of inland crudes in addition to marine shipments of lower priced crudes from the U.S. Gulf Coast when market conditions were favourable.
- Suncor agreed to the sale of its 50% interest in certain assets and liabilities of Pioneer Energy for $182.5 million, before closing adjustments and other costs, highlighting the company's continued focus on core assets that are aligned with Suncor's long-term strategy. This sale is expected to close in the first half of 2015.
- The company completed the acquisition of a sulphur recovery facility that has been integrated into the Montreal refinery operations and is expected to secure the refinery's long-term sulphur recovery needs.

Strategy and Investment Update

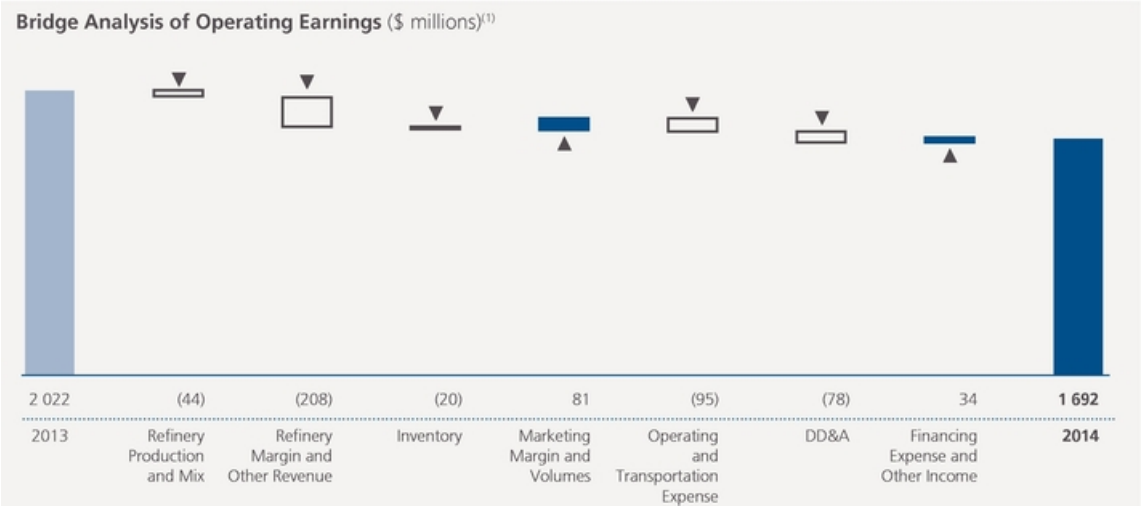
Suncor continues to invest in the profitable growth of its four refineries and further integrating the Montreal refinery with market access initiatives to supply it with discounted North American inland crudes. Crude by rail shipments to the Montreal refinery averaged 33,000 bbls/d in 2014. Crude by rail, combined with the anticipated reversal of Enbridge's Line 9, is expected to provide the company with the flexibility to supply its Montreal refinery with a full slate of inland priced crude. The Montreal refinery, also received marine shipments of lower priced crudes from the U.S. Gulf Coast when market conditions were favourable. During 2014, Suncor completed a project to modify the hydrocracking unit at the Montreal refinery, which is expected to improve overall product yields in 2015, and continues to evaluate further investment opportunities to increase the heavy crude processing capability at the Montreal refinery.

Suncor's Petro-Canada branded outlets maintained its position as a leading retailer by market share in major urban areas of Canada. Suncor will continue to leverage the strong brand to increase non-petroleum revenues through the company's network of convenience stores and car washes, and expand the lubricants product offering, including global expansion in the U.S., Europe and China.

Financial Highlights

Year ended December 31 ($ millions)	2014	2013	2012
Operating revenues	**26 627**	26 658	26 220
Net earnings	**1 692**	2 022	2 137
Operating earnings[1]	**1 692**	2 022	2 152
Refining and Product Supply	**1 385**	1 758	1 877
Marketing	**307**	264	275
Cash flow from operations[1]	**2 178**	2 618	3 138

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.



(1) For an explanation of the construction of this bridge analysis, see the Advisories – Non-GAAP Financial Measures section of this MD&A.

Refining and Supply operations contributed $1.385 billion to operating earnings in 2014, a decrease compared with $1.758 billion in 2013. The decrease was primarily due to the impacts of inventory revaluation in a declining crude price environment, lower benchmark crack spreads and higher transportation and operating expenses, partially offset by stronger price realizations relative to the benchmarks, and favourable foreign exchange rates.

Marketing operations contributed $307 million to operating earnings in 2014, compared to $264 million in 2013, due mainly to stronger retail, wholesale and lubricant margins.

Cash flow from operations was $2.178 billion in 2014, compared to $2.618 billion in 2013, due to the same factors that impacted operating earnings.

Volumes

Year ended December 31	2014	2013	2012
Crude oil processed (mbbls/d)			
Eastern North America	**199.2**	201.7	197.7
Western North America	**228.3**	229.6	233.7
Total	**427.5**	431.3	431.4
Refinery utilization[(1)(2)] (%)			
Eastern North America	**90**	91	89
Western North America	**95**	96	100
Total	**93**	94	95
Refined Product Sales (mbbls/d)			
Gasoline	**235.6**	247.4	252.8
Distillate	**207.5**	209.8	195.0
Other	**88.6**	85.7	90.7
	531.7	542.9	538.5

(1) Effective January 1, 2014, the company increased the nameplate capacity of the Edmonton refinery from 140,000 bbls/d to 142,000 bbls/d. Prior year utilization rates have not been recalculated and reflect the lower nameplate capacity.

(2) Refinery utilization is the amount of crude oil run through crude distillation units, expressed as a percentage of the capacity of these units.

Refinery utilization in Eastern North America averaged 90% in 2014, comparable to 91% in 2013 as both years were impacted by similar planned maintenance events at Montreal and Sarnia.

Refinery utilization in Western North America averaged 95% in 2014, compared to 96% in 2013. The slight decrease from the prior year was primarily due to more maintenance events in 2014 at the Edmonton refinery in addition to a third-party hydrogen supply constraint.

Total sales of refined petroleum products decreased to an average of 531,700 bbls/d in 2014, compared to 542,900 bbls/d in 2013, primarily due to lower throughput volumes as a result of an increase in planned maintenance activities.

Prices and Margins

For Refining and Product Supply, prices and margins for refined products were lower in 2014 compared to 2013.

- In 2014, the impact of FIFO inventory accounting, as used by the company, relative to an estimated LIFO basis of accounting, had a negative impact on net earnings of approximately $290 million after-tax, compared to a positive impact of approximately $79 million after-tax in 2013, due to the decrease in crude feedstock costs in the second half of 2014.
- The Brent and WTI differential narrowed throughout 2014 relative to the prior year, contributing to a decline in benchmark crack spreads across all regions in which the company sells refined products compared to the prior year. However, this was partially offset by the impact of the weakening Canadian dollar and stronger price realizations relative to the benchmarks.
- Refining margins were negatively impacted by the narrowing of inland crude differentials, which increased feedstock costs relative to the benchmark crude prices.

Marketing margins increased primarily due to higher margins for retail, wholesale, and lubricants channels.

Expenses and Other Factors

Operating expenses were higher in 2014 compared to 2013, primarily due to higher energy input costs, higher transportation costs due to higher finished product delivery rates, environmental expenses related to a reclamation provision, and higher maintenance costs. DD&A expense increased in 2014 due to asset additions and costs associated with planned maintenance events in 2014 and 2013. In addition, an impairment was recorded in the second quarter of 2014 related to the construction of a sulphur recovery plant that was no longer required after the acquisition of an existing facility.

Other Items

Disposition of Pioneer Energy Assets

On September 17, 2014, Suncor announced that, along with The Pioneer Group Inc., it had reached an agreement to sell certain assets and liabilities of Pioneer Energy. Suncor, as a 50% owner of Pioneer Energy, is expected to receive $182.5 million before closing adjustments for its share of the assets and liabilities. The transaction is expected to close in the first half of 2015 and is subject to closing conditions, including regulatory approval under the *Competition Act* (Canada).

Planned Maintenance

The company has scheduled planned maintenance events at the Commerce City refinery in the first quarter of 2015 with an expected duration of four weeks. The Edmonton refinery has a five-week planned maintenance event in the second quarter of 2015. The Sarnia refinery has a two-week planned maintenance event in the second quarter of 2015. The Montreal refinery has a one-week planned maintenance event in the third quarter of 2015 and a three-week planned maintenance event in the fourth quarter of 2015. The impact of this maintenance has been reflected in the company's 2015 guidance.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

2014 Highlights

- The Energy Trading business increased the flexibility of Suncor's logistics network by securing rail off-loading facilities with market access into Canadian and U.S. coastal markets, positioning the company to capture global prices on both its current production and future growth.
- The company increased access to U.S. Gulf Coast pricing for both light and heavy crudes by securing capacity on TransCanada's Gulf Coast Pipeline. Investments in storage capacity near the U.S. Gulf Coast increased the company's flexibility to optimize the price received for crude shipments.
- The company completed construction of the 40 MW (gross capacity) Adelaide wind farm in the fourth quarter of 2014.

Strategy and Investment Update

The Energy Trading business supports the company's production by securing market access, optimizing price realizations, managing inventory levels and managing the impacts of external market factors, such as pipeline disruptions or outages at refining customers, while generating trading earnings through established strategies. The Energy Trading business continues to evaluate additional pipeline agreements to support planned production growth.

The Cedar Point wind project continues to progress through the regulatory process and is expected to be operational by the end of 2015. Cedar Point and Adelaide are located in Ontario, and are expected to add 140 MW of gross installed capacity, increasing the capacity of Suncor's wind projects by 55%. The focus for the ethanol operations will be to maintain safe and reliable operations and improve plant profitability through technology improvements.

Financial Highlights

Year ended December 31 ($ millions)	**2014**	2013	2012
Net loss	**(1 422)**	(1 151)	(3)
Adjusted for:			
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**722**	521	(157)
Impact of income tax rate adjustments on deferred income taxes	**—**	—	(20)
Operating (loss) earnings[(1)]	**(700)**	(630)	(180)
Renewable Energy	**78**	72	57
Energy Trading	**66**	116	147
Corporate	**(850)**	(785)	(468)
Eliminations	**6**	(33)	84
Cash flow used in operations[(1)]	**(429)**	(78)	(39)

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Renewable Energy

Year ended December 31	**2014**	2013	2012
Power generation marketed (net gigawatt hours)	**411**	430	429
Ethanol production (thousands of m^3)	**412**	415	413

Suncor's renewable energy assets contributed operating earnings of $78 million in 2014, compared to $72 million in 2013, and increased primarily due to stronger margins on ethanol sales driven by lower feedstock prices partially offset by lower ethanol byproduct revenues in 2014.

Energy Trading

Energy Trading activities contributed operating earnings of $66 million in 2014, compared to $116 million in 2013. The decrease in operating earnings was primarily due to lower gains in the U.S. crude trading strategies due to narrowing differentials, partially offset by higher gains in the natural gas trading strategies.

Corporate

Corporate had an operating loss of $850 million in 2014, compared with an operating loss of $785 million in 2013. The increase in operating loss was primarily due to increased expenditures relating to a company-wide process

improvement initiative, partially offset by lower share-based compensation expense in 2014. Cash flow from operations was higher in 2013 due to an incremental tax recovery related to the company's Canadian operations and the result of settling trading losses in 2014. Suncor capitalized $431 million of its borrowing costs in 2014 as part of the cost of major development assets and construction projects in progress, compared to $397 million in the prior year.

Eliminations

Eliminations reflect the elimination of profit on crude oil sales from Oil Sands and East Coast Canada to Refining and Marketing. Consolidated profits are only realized when the company sells the products produced from intersegment purchases of crude feedstock to third parties. In 2014, $6 million of after-tax intersegment profit was realized, compared to $33 million of profit that was eliminated in 2013.

5. FOURTH QUARTER 2014 ANALYSIS

Financial and Operational Highlights

Three months ended December 31 ($ millions, except as noted)	2014	2013
Net earnings (loss)		
Oil Sands	**180**	469
Exploration and Production	**198**	(101)
Refining and Marketing	**173**	458
Corporate, Energy Trading and Eliminations	**(467)**	(383)
Total	**84**	443
Operating earnings (loss)[1]		
Oil Sands	**180**	400
Exploration and Production	**198**	239
Refining and Marketing	**173**	458
Corporate, Energy Trading and Eliminations	**(165)**	(124)
Total	**386**	973
Cash flow from (used in) operations[1]		
Oil Sands	**875**	1 110
Exploration and Production	**401**	552
Refining and Marketing	**240**	534
Corporate, Energy Trading and Eliminations	**(24)**	154
Total	**1 492**	2 350
Production volumes (mboe/d)		
Oil Sands	**419.3**	446.5
Exploration and Production	**138.3**	111.6
Total	**557.6**	558.1

(1) Non-GAAP financial measures. Operating earnings and cash flow from operations are reconciled below. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Net Earnings

Suncor's consolidated net earnings for the fourth quarter of 2014 were $84 million, compared to $443 million for the prior year quarter. Net earnings were primarily affected by the same factors that influenced operating earnings described in the segmented analysis described below. Other items affecting net earnings over these periods included:

- The after-tax unrealized foreign exchange loss on the revaluation of U.S. dollar denominated debt was $302 million for the fourth quarter of 2014 compared to $259 million for the fourth quarter of 2013.
- In the fourth quarter of 2013, the company recorded after-tax impairment charges of $563 million in the Exploration and Production segment against its assets in Syria, Libya, and E&P Canada. Concurrent with the impairment of its Syrian assets, the company recognized after-tax risk mitigation proceeds of $223 million, previously recorded as a long-term provision.
- In the fourth quarter of 2013, the company recorded an after-tax recovery of $69 million to reduce the previously estimated costs of not proceeding with the Voyageur upgrader project due to an acceleration of project closure activities and a redeployment of resources.

Cash Flow from Operations

Consolidated cash flow from operations was $1.492 billion for the fourth quarter of 2014 compared to $2.350 billion for the prior year quarter. Cash flow from operations was impacted by the same factors that affected operating earnings in the segmented analysis described below.

Segmented Analysis

Oil Sands

Operating earnings for the fourth quarter of 2014 were $180 million, compared to $400 million in the prior year quarter and decreased primarily due to lower Oil Sands production resulting from unplanned maintenance activities and lower price realizations, partially offset by a decrease in mining and upgrading maintenance costs and lower royalty expenses.

Production volumes at Oil Sands operations averaged 384,200 bbls/d in the fourth quarter of 2014, compared to 409,600 bbls/d in the prior year quarter. The decrease was driven primarily by unplanned maintenance at Upgrader 2 and on utility assets impacting upgrading and extraction. This decrease was partially offset by strong Firebag production which achieved above nameplate capacity in the fourth quarter of 2014.

Suncor's share of Syncrude production decreased slightly to an average of 35,100 bbls/d in the fourth quarter of 2014 from 36,900 bbls/d in the fourth quarter of 2013.

Exploration and Production

Exploration and Production operating earnings were $198 million in the fourth quarter of 2014, compared to $239 million in the fourth quarter of 2013. Operating earnings decreased primarily due to lower price realizations and lower production at Buzzard, partially offset by higher production at Terra Nova and higher earnings from Libya.

Production volumes were 138,300 boe/d in the fourth quarter of 2014, compared to 111,600 boe/d in the fourth quarter of 2013. The increase was primarily due to a temporary ramp up of production in Libya which has since been substantially shut in by the end of the fourth quarter, a ten-week off-station maintenance program at the Terra Nova facility that was completed in the prior year quarter, and the start up of production from Golden Eagle, partially offset by natural declines at Hibernia and Buzzard.

Refining and Marketing

For the fourth quarter of 2014, Refining and Marketing operating earnings were $173 million, compared to operating earnings of $458 million for the fourth quarter of 2013. The decrease was primarily due to the impacts of inventory revaluation in a declining crude price environment, less favourable inland crude price differentials, and a small relative build of finished product inventory in comparison to the prior year quarter. This was partially offset by strong refining margins in Western North America relative to the benchmarks and favourable foreign exchange rates.

Refinery crude throughput increased in the fourth quarter of 2014, resulting in an average refinery utilization of 95%, compared to 91% in the prior year quarter. Both quarters were impacted by planned maintenance events at the Sarnia and Montreal refineries; however, the planned maintenance in the fourth quarter of 2014 had a smaller impact on throughput volumes although it did result in less favourable product yields.

Corporate, Energy Trading and Eliminations

Operating loss for Corporate, Energy Trading and Eliminations in the fourth quarter of 2014 was $165 million, compared to a $124 million loss in the fourth quarter of 2013. The increase in operating loss was due primarily to larger foreign exchange losses on working capital as a result of the strengthening U.S. dollar, larger losses on the company's crude trading strategies in the fourth quarter of 2014 and decreased operating earnings in renewable energy as a result of decreasing ethanol byproduct revenues. These factors were partially offset by a share-based compensation expense recovery in the fourth quarter.

6. QUARTERLY FINANCIAL DATA

Financial Summary

Three months ended ($ millions, unless otherwise noted)	**Dec 31 2014**	Sept 30 2014	June 30 2014	Mar 31 2014	Dec 31 2013	Sept 30 2013	June 30 2013	Mar 31 2013
Total production (mboe/d)								
Oil Sands	**419.3**	441.1	403.1	424.4	446.5	423.6	309.4	389.0
Exploration and Production	**138.3**	78.2	115.3	120.9	111.6	171.4	190.7	207.1
	557.6	519.3	518.4	545.3	558.1	595.0	500.1	596.1
Revenues and other income								
Operating revenues, net of royalties	**8 899**	10 175	10 446	10 342	9 814	10 288	9 648	9 843
Other income	**192**	98	203	135	380	85	66	173
	9 091	10 273	10 649	10 447	10 194	10 373	9 714	10 016
Net earnings (loss)	**84**	919	211	1 485	443	1 694	680	1 094
per common share – basic (dollars)	**0.06**	0.63	0.14	1.01	0.30	1.13	0.45	0.72
per common share – diluted (dollars)	**0.06**	0.62	0.14	1.01	0.30	1.13	0.45	0.71
Operating earnings(1)	**386**	1 306	1 135	1 793	973	1 426	934	1 367
per common share – basic(1) (dollars)	**0.27**	0.89	0.77	1.22	0.66	0.95	0.62	0.90
Cash flow from operations(1)	**1 492**	2 280	2 406	2 880	2 350	2 528	2 250	2 284
per common share – basic(1) (dollars)	**1.03**	1.56	1.64	1.96	1.58	1.69	1.49	1.50
ROCE(1) (%) for the twelve months ended	**8.6**	9.4	10.1	12.6	11.5	8.6	8.1	7.1
Common share information (dollars)								
Dividend per common share	**0.28**	0.28	0.23	0.23	0.20	0.20	0.20	0.13
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**36.90**	40.53	45.50	38.61	37.24	36.83	31.00	30.44
New York Stock Exchange (US$)	**31.78**	36.15	42.63	34.96	35.05	35.78	29.49	30.01

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this document. ROCE excludes capitalized costs related to major projects in progress. Operating earnings for each quarter are defined in the Non-GAAP Financial Measures Advisory section and reconciled to GAAP measures in the consolidated Financial Information and Segment Results and Analysis sections of each quarterly Report to Shareholders issued by Suncor (Quarterly Reports) in respect of the relevant quarter of 2014. Cash flow from operations and ROCE for each quarter are defined and reconciled to GAAP measures in the Advisories – Non-GAAP Financial Measures section of each Quarterly Report issued by Suncor in respect of the relevant quarter for 2014.

Business Environment

Three months ended (average for the period ended, except as noted)		Dec 31 2014	Sept 30 2014	June 30 2014	Mar 31 2014	Dec 31 2013	Sept 30 2013	June 30 2013	Mar 31 2013
WTI crude oil at Cushing	US$/bbl	**73.15**	97.20	103.00	98.70	97.45	105.85	94.20	94.35
ICE Brent crude oil at Sullom Voe	US$/bbl	**77.00**	103.40	109.75	107.80	109.35	109.70	103.35	112.65
Dated Brent/Maya FOB price differential	US$/bbl	**10.05**	12.50	13.85	18.45	20.05	10.35	5.50	10.60
MSW at Edmonton	Cdn$/bbl	**67.05**	89.50	97.10	90.70	89.05	105.25	92.90	88.45
WCS at Hardisty	US$/bbl	**58.90**	77.00	82.95	75.55	65.25	88.35	75.05	62.40
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**14.25**	20.20	20.05	23.15	32.20	17.50	19.15	31.95
Condensate at Edmonton	US$/bbl	**70.55**	93.45	105.15	102.65	94.20	103.80	103.30	107.20
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.60**	4.00	4.65	5.70	3.50	2.40	3.50	3.20
Alberta Power Pool Price	Cdn$/MWh	**30.55**	63.90	42.30	61.75	48.40	83.90	123.35	64.10
New York Harbor 3-2-1 crack (1)	US$/bbl	**16.15**	20.50	21.55	20.40	19.60	19.25	25.60	31.20
Chicago 3-2-1 crack (1)	US$/bbl	**14.40**	17.50	19.40	18.35	12.00	15.80	30.70	27.10
Portland 3-2-1 crack (1)	US$/bbl	**12.45**	24.60	26.10	17.40	15.35	19.60	30.60	30.55
Gulf Coast 3-2-1 crack (1)	US$/bbl	**10.15**	19.10	19.55	17.15	13.45	15.95	23.95	28.80
Exchange rate	US$/Cdn$	**0.88**	0.92	0.92	0.91	0.95	0.96	0.98	0.99
Exchange rate (end of period)	US$/Cdn$	**0.86**	0.89	0.94	0.90	0.94	0.97	0.95	0.98

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Significant or Unusual Items Impacting Net Earnings

Trends in Suncor's quarterly earnings and cash flow from operations are driven primarily by production volumes, which can be significantly impacted by major maintenance events – such as planned coker maintenance in the spring and fall of 2014, unplanned maintenance in upgrading and extraction during the second and fourth quarters of 2014, a weather-related site-wide power outage in the third quarter of 2014, maintenance that occurred at Upgrader 1 in Oil Sands in the second quarter of 2013, maintenance that occurred at Terra Nova in the fourth quarter of 2013, as well as third-party outages that impacted Oil Sands in the second, third and fourth quarters of 2013.

Trends in Suncor's quarterly earnings and cash flow from operations are also affected by changes in commodity prices, price differentials, refining crack spreads and foreign exchange rates, as described in the Financial Information section of this MD&A.

In addition to the impacts of changes in production volumes and business environment, net earnings over the last eight quarters were affected by the following events or significant one-time adjustments:

- In the third quarter of 2014, the company recorded an after-tax gain of $61 million relating to the sale of its Wilson Creek oil and gas assets in E&P Canada.
- In the third quarter of 2014, the company recorded a current income tax and associated interest charge of $54 million related to the timing of tax depreciation deductions taken on certain capital expenditures incurred in the Oil Sands segment in a prior period.
- In the second quarter of 2014, Total E&P, the operator of the Joslyn mining project, together with Suncor and the other co-owners of the project agreed to scale back certain development activities in order to focus on engineering studies to further optimize the Joslyn project development plan. As a result of Suncor's assessment of expected future net cash flows and the uncertainty of the project, including the timing of the development plans, Suncor recorded an after-tax impairment charge of $718 million against property, plant and equipment and exploration and evaluation assets.
- In the second quarter of 2014, as a result of the continued closure of certain Libyan export terminals and the company's production plans during the remaining term of the production sharing agreements, Suncor estimated the net recoverable value of its assets in Libya based on an assessment of expected future net cash flows over a range of possible outcomes. As a result of this assessment, the company recorded an after-tax impairment charge of $297 million against property, plant and equipment and exploration and evaluation assets.
- In the second quarter of 2014, the company recorded after-tax impairment charges of $223 million in the Oil Sands segment following a review of certain assets that no longer fit with Suncor's previously revised growth strategies and which could not be repurposed or otherwise deployed. Such assets included a pipeline and related compressor, as well as steam generator components.
- In the second quarter of 2014, the company recorded after-tax earnings of $32 million related to an agreement reached by Suncor to receive a reserves redetermination of 1.2 million barrels of oil related to an interest in a Norwegian asset that Suncor previously owned.
- In 2013, the company recorded after-tax impairment charges of $563 million against E&P assets as follows: Syria – $422 million, Libya – $101 million and E&P Canada – $40 million. Concurrent with the impairment of its Syrian assets, the company recognized after-tax risk mitigation proceeds of $223 million, previously recorded as a long-term provision.
- The first and fourth quarters of 2013 included a net after-tax charge of $58 million as a result of not proceeding with the Voyageur upgrader project, which included costs related to decommissioning and restoration of the Voyageur site and contract cancellations.
- The third quarter of 2013 included an after-tax gain of $130 million relating to the sale of the company's conventional natural gas business in E&P Canada.

7. CAPITAL INVESTMENT UPDATE

Capital and Exploration Expenditures by Segment

Year ended December 31 ($ millions)	**2014**	2013	2012
Oil Sands	**3 826**	4 311	4 957
Exploration and Production	**1 819**	1 483	1 261
Refining and Marketing	**1 021**	890	644
Corporate, Energy Trading and Eliminations	**295**	93	95
Total	**6 961**	6 777	6 957
Less: capitalized interest on debt	**(431)**	(397)	(587)
	6 530	6 380	6 370

Capital and Exploration Expenditures by Type[(1)(2)(3)]

Year ended December 31, 2014 ($ millions)	Sustaining	Growth	**Total**
Oil Sands Base	*997*	*166*	***1 163***
In Situ	*746*	*128*	***874***
Oil Sands Ventures	*269*	*1 235*	***1 504***
Oil Sands	2 012	1 529	**3 541**
Exploration and Production	73	1 612	**1 685**
Refining and Marketing	797	212	**1 009**
Corporate, Energy Trading and Eliminations	132	163	**295**
	3 014	3 516	**6 530**

(1) Capital expenditures in this table exclude capitalized interest on debt.

(2) Growth capital expenditures include capital investments that result in i) an increase in production levels at existing Oil Sands Operations and Refining and Marketing operations; ii) new facilities or operations that increase overall production; iii) new infrastructure and logistics that are required to support higher production levels; iv) new reserves or a positive change in the company's reserves profile in Exploration and Production operations; or v) margin improvement, by increasing revenues or reducing costs.

(3) Sustaining capital expenditures include capital investments that i) ensure compliance or maintain relations with regulators and other stakeholders; ii) improve efficiency and reliability of operations or maintain productive capacity by replacing component assets at the end of their useful lives; iii) deliver existing proved developed reserves for Exploration and Production operations; or iv) maintain current production capacities at existing Oil Sands Operations and Refining and Marketing operations.

In 2014, Suncor spent $6.530 billion on property, plant and equipment and exploration activities, and capitalized $431 million of interest on debt towards major development assets and construction projects. Activity in 2014 included the following:

Oil Sands Base

Oil Sands Base capital expenditures were $1.163 billion, of which $997 million was directed towards sustaining activities as the company continued to progress reliability, safety and environmental sustainment projects. Projects included the construction of assets to support TRO$_{TM}$, the construction of a water treatment plant that is expected to reduce freshwater use, and the commissioning of a booster pump station to maintain high pressures to move tailings efficiently. Additional sustaining capital expenditures were related to planned maintenance in the spring and fall of 2014.

Oil Sands Base growth capital of $166 million included the construction of on-site midstream assets that are currently being used to support production in Oil Sands operations, including hot bitumen cooling and blending facilities, and related storage assets.

In Situ

In Situ sustaining capital expenditures were $874 million, of which $746 million was directed towards sustaining capital expenditures. Sustaining capital in 2014 was focused on the ongoing design and construction of well pads that are expected to maintain existing production levels at Firebag and MacKay River in future years as production from existing well pads decline.

Growth capital of $128 million in 2014 was focused on completing the MacKay River debottlenecking project, as well as new well pads related to the project. First oil from this project was achieved in the third quarter of 2014.

Oil Sands Ventures

Oil Sands ventures growth capital expenditures were $1.235 billion in 2014, including the Fort Hills mining project expenditures, which were directed towards design engineering, site preparation, procurement of long-lead items and field construction activities. All critical milestones were substantially achieved on the Fort Hills project in 2014. Overall aggregate engineering and procurement progress is approximately 65% complete. Construction activities are approximately 20% complete and included substantial completion of the foundations for the ore processing facility and primary extraction area, in addition to the completion of water treatment facilities.

Suncor's share of capital expenditures for the Syncrude joint operation in 2014 was $269 million of sustaining capital, which included expenditures for mine train replacement at the Mildred Lake mining area, and construction of a centrifuge plant for tailing management.

Exploration and Production

Exploration and Production capital and exploration expenditures were $1.685 billion in 2014, of which $1.612 billion was directed towards growth and exploration.

Growth spending included $245 million for Golden Eagle as spending ramped up to achieve first oil in late October. Growth spending for Hebron was $712 million in 2014, which focused on detailed engineering and construction of the gravity-based structure and topsides which were successfully moved from dry dock to its deepwater construction site in the third quarter of 2014. First oil is expected at Hebron in 2017.

Growth spending of approximately $256 million primarily focused on advancing the multiple low cost field extension projects currently underway which leverage existing facilities and infrastructure at East Coast Canada. Spending at the HSEU project has been primarily focused on development drilling activities as well as commencing water injection at the end of 2014, with production ramping up in the last half of 2015. At the SWRX project, expenditures were primarily focused on procurement, construction, and installation activities in 2014; first oil is expected in the second quarter of 2015. The HSEU and SWRX projects are expected to provide incremental production and extend the productive life of the existing fields. A sanction decision for the White Rose Extension Project has been deferred by the co-owners in light of the current crude price environment.

During 2014, the company participated in the drilling of two appraisal wells on the Butch prospect in Norway. Both wells were deemed to be non-commercial and charged to exploration expense in 2014.

Sustaining capital expenditures focused primarily on the planned maintenance programs for East Coast Canada assets.

Refining and Marketing

Refining and Marketing spent $1.009 billion on capital expenditures in 2014, of which $797 million was directed to sustaining activities focused on planned maintenance events at the company's refineries as wells at its retail business.

Growth spending of $212 million included work that was completed in the fourth quarter of 2014 to modify the hydrocracking unit at the Montreal refinery. These modifications are expected to improve overall product yields at the refinery. Further spending included completing facilities to enable the Montreal refinery to receive more inland crudes.

Significant Growth Projects Update[1][4]

At December 31, 2014	Working Interest (%)	Description	Cost Estimate ($ millions)	Project Spend to date ($ millions)	Expected First Oil Date[3]
Operated					
Fort Hills	40.80	73.4 mbbls/d (net)	5 500	1 315	Q4 2017
Non-operated[2]					
Golden Eagle	26.69	18.7 mboe/d (net)	1 000 (+/-10%)	715	Q4 2014
Hebron	22.73	34.2 mboe/d (net)	2 800 (+/-10%)	1 229	Q4 2017

(1) Cost Estimate and Project Spend to date figures reflect post-sanction estimates and expenditures, excluding capitalized interest.

(2) Cost estimates are based on the most recent estimate provided by the operator.

(3) Expenditures to complete the project may extend beyond the first oil date.

(4) The Capital Investment Update section contains forward-looking information. See the Advisories – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

The table above summarizes major growth projects that have been sanctioned for development by the company. Other potential material growth projects have not yet received a final investment decision by the company or its Board of Directors.

The Fort Hills mining project will be developed using traditional open-pit truck and shovel techniques, and solvent-based extraction technology that will allow the mine to produce bitumen product that is sold directly to market. The project is scheduled to produce first oil as early as the fourth quarter of 2017 and achieve 90% of its planned gross production capacity of 180,000 bbls/d within twelve months. Project activities in 2015 are expected to focus on the completion of detailed engineering on the secondary extraction and utilities areas, the continued ramp up of procurement spending, and field construction activities across all areas.

The Golden Eagle facilities are designed for 70,000 boe/d of gross production capacity from a combined production, utilities, and accommodation platform, in addition to a separate well head platform. First oil was achieved in late 2014 following the installation of the combined platform and the commencement of development drilling. Activity in 2015 will include further development drilling as production ramps up to its peak production rate.

The co-owners for the Hebron project sanctioned development on December 31, 2012. The Hebron field includes a gravity-based structure design supporting an expected gross oil production rate of 150,000 bbls/d. Project activity in 2015 is expected to focus on construction of the gravity-based structure and topsides.

Other Capital Projects

Suncor also anticipates 2015 capital expenditures to be directed to the following projects and initiatives:

Oil Sands Operations

For 2015, plans for sustaining capital continue to focus on planned maintenance, tailings management operations offsetting natural production declines, and maintaining production capacity at existing facilities. Sustaining expenditures include new well pads for In Situ assets and equipment replacement for the mine.

Growth capital consists primarily of continuing the construction of midstream assets that will support Oil Sands operations, including hot bitumen cooling and blending facilities, and related storage assets.

Oil Sands Ventures

Sustaining capital expenditures in 2015 for Syncrude are expected to focus on planned maintenance, development of tailings management facilities, improvements to utilities facilities and capital to complete mine train replacements.

Exploration and Production

In addition to further spending to advance the HSEU and SWRX projects, Suncor continues to evaluate the operated Beta prospect with plans for an appraisal well in 2015. Evaluation activities will also continue on the non-operated Butch licence following the drilling in 2014. The company also expects to drill at six exploration locations in the North

Sea and on the east coast of Canada in 2015. Two of these locations will be operated by Suncor.

Refining and Marketing

The company expects that Sustaining capital will focus on planned maintenance events and routine asset replacement.

Renewable Energy

Growth capital will be focused on progressing projects within the company's renewable business including the Cedar Point project that received regulatory approval in August 2014. There is currently an appeal of this permit in progress and the final decision of that appeal is expected in early March 2015. Detailed engineering is concluding and construction is expected to be completed in 2015. The project is expected to add 100 MW of gross installed capacity. Suncor has also invested in biodiesel technology to capture a production cost advantage, through interests in both a technology company and the retrofit of a biodiesel plant, which is expected to be completed by the end of 2015.

8. FINANCIAL CONDITION AND LIQUIDITY

Liquidity and Capital Resources

At December 31 ($ millions, except as noted)	2014	2013	2012
Net cash from (used in)			
Operating activities	**8 936**	10 100	8 859
Investing activities	**(6 863)**	(6 533)	(6 644)
Financing activities	**(1 872)**	(2 832)	(1 592)
Foreign exchange gain (loss) on cash and cash equivalents	**92**	82	(19)
Increase in cash and cash equivalents	**293**	817	604
Cash and Cash equivalents, end of year	**5 495**	5 202	4 385
Return on Capital Employed (%)[1][2]			
Excluding major projects in progress	**8.6**	11.5	7.2
Including major projects in progress	**7.5**	9.9	5.8
Net debt to cash flow from operations[2] (times)	**0.9**	0.7	0.7
Interest coverage on long-term debt (times)			
Earnings basis[3]	**6.6**	9.5	7.9
Cash flow from operations basis[2][4]	**15.5**	16.8	17.7

(1) Non-GAAP financial measure. ROCE is reconciled in the Advisories – Non-GAAP Financial Measures section of this MD&A.

(2) Cash flow from operations and metrics that use cash flow from operations are non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

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

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

Cash Flow from Operating Activities

Cash from operating activities was $8.936 billion in 2014 compared to $10.1 billion in 2013. The decrease was primarily due to lower production in the Exploration and Production segment and declining price realizations in the last half of 2014 in both the Exploration and Production and Refining and Marketing segments.

Cash Flow used in Investment Activities

Cash flow used in investing activities was $6.863 billion in 2014 compared to $6.533 billion in 2013. The increase in net cash flow used in 2014 was primarily due to lower divestiture proceeds as 2013 included the proceeds from the disposal of a significant portion of the company's natural gas business as both periods had similar expenditures. Investing activities in 2014 also included proceeds received from the disposition of the Wilson Creek assets in the Exploration and Production segment and the acquisition of a sulphur recovery facility in the Refining and Marketing segment.

Cash Flow used in Financing Activities

Cash flow used in financing activities was $1.872 billion in 2014 compared to $2.832 billion in 2013. The decrease in cash flow used in 2014 was primarily due to the issuance of $750 million in U.S. dollar debt and $750 million in Canadian dollar debt, partially offset by the repayment of $400 million in U.S. dollar debt and an increase in dividends paid.

Capital Resources

Suncor's capital resources consist primarily of cash flow from operations, cash and cash equivalents, and available lines of credit. Suncor's management believes the company will have the capital resources to fund its planned 2015 capital spending program of $6.2 to $6.8 billion and meet working capital requirements through existing cash balances and short-term investments, cash flow from operations, available committed credit facilities, issuing commercial paper and issuing long-term notes or debentures. The company's cash flow from operations depends on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates. As a result of the decline in commodity prices, on January 13, 2015, Suncor announced a reduction to its 2015 budgeted capital spending and operating cost reduction targets to preserve liquidity and capital resources. If additional capital is required, the

company believes financing will be available at commercial terms and rates.

The company has invested excess cash in short-term financial instruments that are presented as cash and cash equivalents on the Consolidated Balance Sheets. The objectives of the company's short-term investment portfolio are to ensure the preservation of capital, maintain adequate liquidity to meet Suncor's cash flow requirements and deliver competitive returns consistent with the quality and diversification of investments within acceptable risk parameters. The maximum weighted average term to maturity of the short-term investment portfolio does not exceed six months, and all investments are with counterparties with investment grade debt ratings.

Available Sources of Liquidity

Cash and Cash Equivalents

Included in the cash and cash equivalents of $5.495 billion at December 31, 2014 are short-term investments with weighted average terms to maturity of approximately 44 days. In 2014, the company earned approximately $34 million of interest income on this portfolio.

Financing Activities

Management of debt levels continues to be a priority for Suncor given the company's long-term growth plans. Suncor's management believes a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels.

Suncor's interest on debt (before capitalized interest) in 2014 was $739 million which was comparable to $703 million in 2013.

Unutilized lines of credit at December 31, 2014 were $4.275 billion, compared to $4.536 billion at December 31, 2013.

A summary of available and unutilized credit facilities is as follows:

($ millions)	2014
Fully revolving for a period of one year after term-out date (April 2016)	2 000
Fully revolving and expires in 2016	1 550
Fully revolving for a period of four years and expires in April 2019	3 000
Can be terminated at any time at the option of the lenders	138
Total credit facilities	6 688
Credit facilities supporting outstanding commercial paper	(806)
Credit facilities supporting standby letters of credit	(1 607)
Total unutilized credit facilities	4 275

Total Debt to Total Debt Plus Shareholders' Equity

Suncor is subject to financial and operating covenants related to its bank debt and public market debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. The company is in compliance with its financial covenant that requires total debt to not exceed 65% of its total debt plus shareholders' equity. At December 31, 2014, total debt to total debt plus shareholders' equity was 24% (December 31, 2013 – 22%). The company is currently in compliance with all operating covenants as at December 31, 2014.

At December 31 ($ millions, except as noted)	2014	2013
Short-term debt	**806**	798
Current portion of long-term debt	**34**	457
Long-term debt	**12 489**	10 203
Total debt	**13 329**	11 458
Less: Cash and cash equivalents	**5 495**	5 202
Net debt	**7 834**	6 256
Shareholders' equity	**41 603**	41 180
Total debt plus shareholders' equity	**54 932**	52 638

Total debt to total debt plus shareholders' equity (%)	**24**	22

Change in Net Debt

($ millions)	
Net debt – December 31, 2013	6 256
Increase in net debt	1 578
Net debt – December 31, 2014	7 834
Change in net debt	
Cash flow from operations	9 058
Capital and exploration expenditures and other investments	(7 025)
Acquisition	(121)
Proceeds from divestitures	224
Dividends less proceeds from exercise of share options	(1 243)
Repurchase of common shares	(1 671)
Change in non-cash working capital	(63)
Foreign exchange on cash, debt and other balances	(737)
	(1 578)

At December 31, 2014, Suncor's net debt was $7.834 billion, compared to $6.256 billion at December 31, 2013. During 2014, net debt increased by $1.578 million, largely due to cash returned to shareholders in the form of share repurchases and dividends, and the impact of the weakening Canadian dollar relative to the U.S. dollar on the valuation of U.S. denominated debt, partially offset by cash flow from operations that exceeded capital and exploration expenditures.

For the year ended December 31, 2014, the company's net debt to cash flow from operations measure was 0.9 times, which met management's target of less than 2.0 times.

Credit Ratings

The following information regarding the company's credit ratings is provided as it relates to the company's cost of funds and liquidity. In particular, the company's ability to access unsecured funding markets and to engage in certain activities on a cost-effective basis is primarily dependent upon maintaining a strong credit rating. A lowering of the company's credit rating may also have potentially adverse consequences for the company's funding capacity or access to the capital markets, may affect the company's ability, and the cost, to enter into normal course derivative or hedging transactions, and may require the company to post additional collateral under certain contracts.

The company's long-term senior debt ratings are:

Long-Term Senior Debt	Rating	Long-Term Outlook
Standard & Poor's	A-	Stable
Dominion Bond Rating Service	A (low)	Stable
Moody's Investors Service	A3	Stable

The company's commercial paper ratings are:

Commercial Paper	Cdn Program Rating	US Program Rating
Standard & Poor's	A-1 (low)	A-2
Dominion Bond Rating Service	R-1 (low)	R-1 (low)
Moody's Investors Service	Not rated	P-2

Refer to the Description of Capital Structure – Credit Ratings section of Suncor's 2014 AIF for a description of credit ratings listed above.

Common Shares

Outstanding Shares

December 31, 2014 (thousands)

Common shares	1 444 119
Common share options – exercisable and non-exercisable	27 464
Common share options – exercisable	18 084

As at February 23, 2015, the total number of common shares outstanding was 1,445,044,453, and the total number of exercisable and non-exercisable common share options outstanding was 33,376,928. Once exercisable, each outstanding common share option is convertible into one common share.

Share Repurchases

On August 5, 2014, Suncor renewed its normal course issuer bid to continue to purchase shares under its previously announced buyback program (the 2014 NCIB) through the facilities of the Toronto Stock Exchange, New York Stock Exchange and/or alternative trading platforms. Pursuant to the 2014 NCIB, Suncor may purchase for cancellation up to approximately $1.1 billion worth of its common shares between August 5, 2014 and August 4, 2015 and has agreed that it will not purchase more than 44,045,388 common shares, which was equal to approximately 3% of Suncor's issued and outstanding common shares at the time of program renewal.

During 2014, the company repurchased 42,026,992 common shares at an average price of $39.76 per share, for a total repurchase cost of $1.671 billion.

Shareholders may obtain a copy of the company's Notice of Intention to make a Normal Course Issuer Bid in relation to the 2014 NCIB, without charge, by contacting Investor Relations.

Further repurchases under the program have been suspended at this time in response to the lower crude price environment.

Since commencing its share buyback program in 2011, Suncor has purchased 155.5 million common shares for a total return to shareholders of $5.297 billion under this program.

At December 31 ($ millions, except as noted)	**2014**	2013	2012	2011
Share repurchase activities (thousands of common shares)				
Shares repurchased directly	**42 027**	49 492	46 862	17 128
Shares repurchased through exercise of put options	**—**	—	—	—
	42 027	49 492	46 862	17 128
Share repurchase cost ($ millions)				
Repurchase cost	**1 671**	1 675	1 452	500
Option premiums received	**—**	—	(1)	—
	1 671	1 675	1 451	500
Weighted average repurchase price per share, net of option premiums (dollars per share)	**39.76**	33.84	30.96	29.19

Contractual Obligations, Commitments, Guarantees, and Off-Balance Sheet Arrangements

In addition to the enforceable and legally binding obligations in the table below, Suncor has other obligations for goods and services that were entered into in the normal course of business, which may terminate on short notice, including commitments for the purchase of commodities for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase.

The company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources.

In the normal course of business, the company is obligated to make future payments, including contractual obligations and non-cancellable commitments.

	Payment due by period						
($ millions)	2015	2016	2017	2018	2019	2020 and beyond	Total
Fixed and revolving term debt[(1)]	**1 509**	**690**	**690**	**3 536**	**519**	**16 003**	**22 947**
Finance lease obligations	**112**	**113**	**111**	**108**	**109**	**2 123**	**2 676**
Decommissioning and restoration costs[(2)]	**381**	**458**	**345**	**357**	**311**	**7 048**	**8 900**
Operating lease agreements, pipeline capacity and energy services commitments[(3)]	**1 728**	**1 420**	**1 264**	**1 126**	**1 031**	**6 816**	**13 385**
Exploration work commitments	**146**	**26**	**—**	**141**	**108**	**253**	**674**
Other long-term obligations[(4)]	**129**	**15**	**8**	**8**	**8**	**34**	**202**
Total	**4 005**	**2 722**	**2 418**	**5 276**	**2 086**	**32 277**	**48 784**

(1) Includes debt that is redeemable at Suncor's option and interest payments on fixed-term debt.

(2) Represents the undiscounted amount of decommissioning and restoration costs.

(3) The company has also entered into various pipeline commitments which are awaiting regulatory approval. In the event regulatory approval is not obtained, Suncor has committed to reimbursing certain costs to the service provider.

(4) Includes the Libya ESPA signature bonus and merger consent, and Fort Hills purchase obligations. See the Other Long-Term Liabilities note to the audited Consolidated Financial

Statements.

Transactions with Related Parties

The company enters into transactions with related parties in the normal course of business. These transactions primarily include sales to associated entities in the company's Refining and Marketing segment. For more information on these transactions and for a summary of Compensation of Key Management Personnel, refer to note 31 to the 2014 audited Consolidated Financial Statements.

Financial Instruments

Suncor periodically enters into derivative contracts for risk management purposes. The derivative contracts hedge risks related to purchases and sales of commodities, to manage exposure to interest rates and to hedge risks specific to individual transactions. For the year ended December 31, 2014, the pre-tax earnings impact for risk management activities was a gain of $176 million (2013 – pre-tax loss of $18 million).

The company's Energy Trading business uses crude oil, natural gas, refined products and other derivative contracts to generate net earnings. For the year ended December 31, 2014, the pre-tax earnings impact for Energy Trading activities was a gain of $173 million (2013 – pre-tax gain of $176 million).

Assets Available for Sale relate to the company's investment in Pioneer Energy. As a result of the third-party agreement to sell the company's share of its assets of Pioneer Energy, Suncor increased the fair value of its investment in Pioneer Energy by $98 million to $183 million in the third quarter of 2014 based on the agreed upon selling price.

Gains or losses related to derivatives are recorded as Other Income in the Consolidated Statements of Comprehensive Income.

($ millions)	Assets Available for Sale	Energy Trading	Risk Management	Total
Fair value of contracts, outstanding – January 1, 2013	—	(43)	(1)	(44)
Fair value of contracts realized during the year	—	(271)	18	(253)
Changes in fair value during the year	—	176	(18)	158
Fair value of contracts, outstanding – December 31, 2013	—	(138)	(1)	(139)
Fair value of contracts realized during the year	—	(15)	(65)	(80)
Changes in fair value during the year	—	173	176	349
Assets available for sale	183	—	—	183
Fair value outstanding – December 31, 2014	183	20	110	313

The fair value of derivative contracts are recorded in the Consolidated Balance Sheets.

Fair value of derivative contracts at December 31 ($ millions)	2014	2013
Accounts receivable	**211**	225
Accounts payable	**(81)**	(364)
Assets available for sale	**183**	—
	313	(139)

Risks Associated with Derivative Financial Instruments

Suncor may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to fulfil their obligations under these contracts. The company minimizes this risk by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties. Suncor's exposure is limited to those counterparties holding derivative contracts with net positive fair values at a reporting date.

Suncor's risk management activities are subject to periodic reviews by management to determine appropriate hedging requirements based on the company's tolerance for exposure to market volatility, as well as the need for stable cash flow to finance future growth. Energy Trading activities are governed by a separate risk management group that reviews and monitors practices and policies and provides independent verification and valuation of these activities.

For further details on our derivative financial instruments, including assumptions made in the calculation of fair value, a sensitivity analysis of the effect of changes in commodity prices on our derivative financial instruments, and additional discussion of exposure to risks and mitigation activities, see the Financial Instruments and Risk Management note in our 2014 audited Consolidated Financial Statements.

9. ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Changes in Accounting Policies

Suncor's significant accounting policies are described in notes 3 to the audited Consolidated Financial Statements for the year ended December 31, 2014.

Effective January 1, 2014, the company adopted the following new and amended IFRS standards and interpretations.

Offsetting Financial Assets and Financial Liabilities

International Accounting Standard (IAS) 32 *Financial Instruments: Presentation* amendments clarified the requirements for offsetting financial assets and liabilities. The amendments clarified that the right to offset must be available on the current date and cannot be contingent on a future event. The adoption of this standard did not have a material impact on the company's consolidated financial statements.

Levies

International Financial Reporting Interpretations Committee (IFRIC) 21 *Levies* clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that a levy liability is accrued progressively only if the activity that triggers payment occurs over a period of time, and that a liability should not be recognized before the specified minimum threshold to trigger that liability is reached. This interpretation did not have a material impact to the company's consolidated financial statements.

Recently Announced Accounting Standards

The standards and interpretations that are issued, but not yet effective up to the date of issuance of the company's financial statements, and that may have an impact on the disclosures and financial position of the company, are disclosed below. The company intends to adopt these standards and interpretations, if applicable, when they become effective.

Accounting for Acquisitions of Interests in Joint Operations

In May 2014, the IASB issued amendments to IFRS 11 *Joint Arrangements* to clarify that the acquirer of an interest in a joint operation in which the activity constitutes a business is required to apply all of the principles of business combinations accounting in IFRS 3 *Business Combinations*. Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the company in the event it increases or decreases its ownership share in an existing joint operation or invests in a new joint operation.

Sale or Contribution of Assets between an Investor and its Associate or Joint Venture

In September 2014, the IASB issued amendments to address an inconsistency between the requirements in IFRS 10 *Consolidated Financial Statements* and those in IAS 28 *Investments in Associates and Joint Ventures* regarding the sale or contribution of assets between an investor and its associate or joint venture. The amendment clarified that a full gain or loss is recognized when a transaction involves a business. A partial gain or loss is recognized when a transaction involves assets that do not constitute a business. Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the company in the event that it has transactions with Associates or Joint Ventures.

Disclosure Initiative

In December 2014, the IASB issued narrow-focus amendments to IAS 1 *Presentation of Financial Statements* to clarify existing requirements related to materiality, order of notes, subtotals, accounting policies and disaggregation. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amended standard is not expected to have a material impact on the company's disclosure.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers.* It replaces existing revenue recognition guidance and provides a single, principles based five-step model to be applied to all contracts with customers. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2017, with earlier application permitted. The company is currently assessing the impact of this standard.

Financial Instruments: Recognition and Measurement

In July 2014, IFRS 9 *Financial Instruments* was issued as a complete standard including the requirements previously issued related to classification and measurement of financial assets and liabilities and additional amendments to introduce a new expected loss impairment model for financial assets including credit losses. Retrospective application of this standard with certain exemptions is effective for fiscal years beginning on or after January 1,

2018, with earlier application permitted. The company is currently assessing the impact of this standard.

Significant Accounting Estimates and Judgments

The preparation of financial statements in accordance with GAAP requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues, expenses, gains, losses, and disclosures of contingencies. These estimates and judgments are subject to change based on experience and new information.

Significant accounting estimates are those estimates that require management to make assumptions about matters that are highly uncertain at the time the estimate is made, and those estimates where changes in significant assumptions that are within a range of reasonably possible outcomes would have a material impact on the company's financial condition, changes in financial condition or financial performance.

Significant judgments are those judgments made by management in the process of applying the company's accounting policies and that have the most significant impact on the amounts recognized in the Consolidated Financial Statements.

Significant accounting estimates and judgments are reviewed annually by the Audit Committee of the Board of Directors. The following are the Significant accounting estimates used in the preparation of Suncor's December 31, 2014 audited Consolidated Financial Statements.

Oil and Gas Reserves and Resources

Measurements of depletion, depreciation, impairment, and decommissioning and restoration obligations are determined in part based on the company's estimate of oil and gas reserves and resources. The estimation of reserves and resources is an inherently complex process and involves the exercise of professional judgment. All reserves and certain resources have been evaluated at December 31, 2014 by independent qualified reserves evaluators. Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Estimates reflect market and regulatory conditions existing at December 31, 2014, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Oil and Gas Activities

The company is required to apply judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the initial costs of these activities are capitalized.

Exploration and Evaluation Costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The company is required to make judgments about future events and circumstances and applies estimates to assess the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop the project. Level of drilling success, or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures are important judgments when making this determination.

Project Development

Management uses judgment to determine when exploration and evaluation assets are reclassified to Property, Plant and Equipment. This decision considers several factors, including the existence of reserves, appropriate approvals from regulatory bodies and the company's internal project approval processes.

Determination of Cash Generating Units (CGU)

A CGU is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations.

Asset Impairment and Reversals

Management applies judgment in assessing the existence of impairment and impairment reversal indicators based on various internal and external factors.

The recoverable amount of CGUs and individual assets is determined based on the higher of fair value less costs of disposal or value-in-use calculations. The key estimates the company applies in determining the recoverable amount normally include estimated future commodity prices, expected production volumes, future operating and development costs, discount rates, tax rates, refining margins, and the timing of cash flows. In determining the recoverable amount, management may also be required to make judgments regarding the likelihood of occurrence of a future event. Changes to these estimates and judgments

will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value.

Regardless of any indication of impairment, the company must complete an annual impairment assessment for any CGU, or group of CGUs, whose net carrying value includes indefinite-life intangible assets or an allocation of goodwill. For Suncor, this includes impairment assessments of the Oil Sands segment and the Refining and Marketing segment. For 2014, the company completed this review as at October 31, 2014, and determined that the underlying CGUs were not impaired.

During the fourth quarter of 2014, an impairment indicator existed due to a significant decline in benchmark crude prices, and as such, the company completed impairment assessments for its CGUs in the Oil Sands and Exploration and Production segments as at December 31, 2014 and determined that the underlying CGUs were not impaired.

Refer to note 10 to the 2014 audited Consolidated Financial Statements for impairments recorded during 2014.

Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of Exploration and Evaluation assets and Property, Plant and Equipment. Management applies judgment in assessing the existence and extent, as well as the expected method of reclamation of the company's decommissioning and restoration obligations at the end of each reporting period. Management also uses judgment to determine whether the nature of the activities performed is related to decommissioning and restoration activities or operating activities.

In addition, these provisions are based on estimated costs, which take into account the anticipated method and extent of restoration, technological advances and the possible future use of the site. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience, prices and closure plans. The estimated timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to estimates related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

Suncor's provision for decommissioning and restoration costs increased by $0.9 billion in 2014 to $8.9 billion (undiscounted). The most significant change in the provision related to a change in the discount rate, increased disturbance and an increase in certain cost estimates in the Oil Sands and Exploration and Production segments. The provision also increased due to a decrease in the average credit-adjusted discount rate (2014 – 3.92%; 2013 – 4.51%).

Employee Future Benefits

The company provides benefits to employees, including pensions and other post-retirement benefits. The cost of defined benefit pension plans and other post-retirement benefits received by employees is estimated based on actuarial valuation methods that require professional judgment. Estimates typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, the return on plan assets, mortality rates and future medical costs. Changes to these estimates may have a material impact on the amounts presented.

The fair value of plan assets is determined using market values. The estimated rate of return on plan assets in the portfolio considers the current level of returns on fixed income assets, the historical level of risk premium associated with other asset classes and the expected future returns on all asset classes. The discount rate assumption is based on the year-end interest rates for high-quality bonds that mature at times concurrent with the company's benefit obligations. The estimated rate for compensation increases is based on management's judgment.

Actuarial valuations are subject to management's judgment. Actuarial gains and losses comprise changes to assumptions related to discount rates, expected return on plan assets and annual rates for compensation increases. They are accounted for on a prospective basis and may have a material impact on the amounts presented.

Other Provisions

The determination of other provisions, including, but not limited to, provisions for royalty disputes, onerous contracts, litigation and constructive obligations, is a complex process that involves judgments about the outcomes of future events, the interpretation of laws and regulations, and estimates on timing and amount of expected future cash flows and discount rates.

The company is involved in litigation and claims in the normal course of operations. As at December 31, 2014, management believes the result of any settlements related to such litigation or claims would not materially affect the financial position of the company.

Income Taxes

Management evaluates tax positions, annually or when circumstances require, which involves judgment and could be subject to differing interpretations of applicable tax legislation. The company recognizes a tax provision when a payment to tax authorities is considered probable. However, the results of audits and reassessments and

changes in the interpretations of standards may result in changes to those positions and potentially a material increase or decrease in the company's assets, liabilities and net earnings.

Deferred Income Taxes

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's judgment of the likelihood of a future outflow, estimates of the expected settlement amount, timing of reversals, and the tax laws in the jurisdictions in which the company operates.

Control and Significant Influence

Control is defined as the power to govern the financial and operating decisions of an entity so as to obtain benefits from its activities, and significant influence is defined as the power to participate in the financial and operating decisions of the investee. The assessment of whether the company has control, joint control, or significant influence over another entity requires judgment of the impact it has over the financial and operating decisions of the entity and the extent of the benefits it obtains.

Joint Arrangements

The classification of joint arrangements structured through separate vehicles as either joint ventures or joint operations requires significant judgment and depends on the legal form and contractual terms of the arrangement as well as other facts and circumstances. These include whether there is exclusive dependence on the parties to the joint arrangement for cash flows through the sale of product and funding of operations, and to assess the rights of the economic benefits of the assets and obligation for funding the liabilities of the arrangements. A joint arrangement whereby the parties take their share of substantially all of the output of the joint arrangement would be an indicator for classification as a joint operation, regardless of structure of the arrangement, and accounted for by recognizing the company's share of assets and liabilities jointly owned and incurred, and the recognition of its share of revenue and expenses of the joint operation.

Fair Value of Financial Instruments

The fair value of financial instruments is determined whenever possible based on observable market data. If not available, the company uses third-party models and valuation methodologies that utilize observable market data, including forward commodity prices, foreign exchange rates and interest rates to estimate the fair value of financial instruments, including derivatives. In addition to market information, the company incorporates transaction-specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk.

Functional Currency

The designation of the company's functional currency is a management judgment based on the composition of revenue and costs in the locations in which it operates.

10. RISK FACTORS

Suncor is committed to a proactive program of enterprise risk management intended to enable decision-making through consistent identification of risks inherent to its assets, activities and operations. Some of these risks are common to operations in the oil and gas industry as a whole, while some are unique to 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.

Volatility of Commodity Prices

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 prices for all of these commodities can be influenced by global and regional supply and demand factors, which are factors that are beyond our control and can result in a high degree of price volatility.

Crude oil prices are also affected by, among other things, global economic health and global economic growth (particularly in emerging markets), pipeline constraints, regional and international supply and demand imbalances, political developments, compliance or non-compliance with quotas agreed upon by Organization of Petroleum Exporting Countries (OPEC) members, decisions by OPEC not to impose quotas on its 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.

Refined petroleum products prices and refining margins are also affected by, among other things, crude oil prices, the availability of crude oil and other feedstock, 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.

In addition, oil and natural gas producers in North America, and particularly in Canada, may receive discounted prices for their production relative to certain international prices, due to constraints on the ability to transport and sell such products to international markets. A failure to resolve such constraints may result in continued discounted or reduced commodity prices realized by oil and natural gas producers such as Suncor.

Through the latter half of 2014 and into 2015, world oil prices have declined significantly. A prolonged period of low and/or volatile prices could affect the value of our upstream and downstream assets and the level of spending on growth projects, and could result in the curtailment of production from some properties and/or the impairment of that property's 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, and may also lead to the impairment of assets, or the cancellation or deferral of Suncor's growth projects.

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 greenhouse gas (GHG) emissions 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, or interpretation thereof, could impact Suncor's existing and planned projects as well as impose costs on compliance, resulting in increased capital expenditures and operating expenses. Changes in government policy or regulation can also have an indirect impact on Suncor, including opposition to new North American pipeline systems, such as the Keystone XL or the Northern Gateway proposals. The result of such changes can also lead to additional compliance costs and staffing and resource levels, and also increase exposure to other risks to Suncor's business, including environmental or safety non-compliance and permit approvals.

Income Taxes

Pursuant to the previously disclosed 2013 proposal letter from the Canada Revenue Agency (CRA), in 2014, the company received a Notice of Reassessment (NOR) from the CRA, regarding the income tax treatment of realized losses in 2007 on the settlement of certain derivative contracts. The total amount of the NOR including tax,

penalty and interest was approximately $920 million. Also during the year:

- The company received NORs related to the derivative contracts from Quebec and Ontario for approximately $42 million and $100 million, respectively. The Alberta NOR (approximately $124 million) was received in the first quarter of 2015.
- The company provided security to the CRA and the Provinces of Quebec and Ontario for approximately $610 million.
- The company filed Notices of Objection with the CRA and the Provinces of Quebec and Ontario.
- The company filed a Notice of Appeal with the Tax Court of Canada.

If the company is unsuccessful in defending its tax filing position, it could be subject to an earnings and cash impact of up to $1.2 billion.

Royalties

Royalties can be impacted by changes in crude oil and natural gas pricing, production volumes, 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. The final determination of these events may have a material impact on royalties payable to provincial and local governments and on the company's royalties expense.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Operational Outages and Major Environmental or Safety Incidents

Each of Suncor's primary operating businesses – Oil Sands, E&P, and Refining and Marketing – demands significant levels of investment in the design, operation and maintenance of facilities, and, therefore, carries the additional economic risk associated with operating reliably or enduring a protracted operational outage.

The company's 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, fines, civil suits or criminal charges against the company.

Generally, Suncor's operations are subject to operational hazards and risks such as fires, explosions, blow-outs, power outages, severe winter climate conditions and other extreme weather conditions, rail car incident or derailment 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 Suncor's 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. The company is also subject to operational risks such as sabotage, terrorism, trespass, theft and malicious software or network attacks.

In addition to the foregoing factors that affect Suncor's business generally, each business unit is susceptible to additional risks due to the nature of its business, as follows:

- Oil Sands operations are susceptible to loss of production, slowdowns, shutdowns or restrictions on our ability to produce higher value products, due to the failure of any one or more of its interdependent component systems.
- 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 in the 2014 AIF. Refer also to Significant Risk Factors and Uncertainties Affecting Reserves Data.
- E&P offshore operations occur in areas subject to hurricanes and other extreme weather conditions, such as winter storms, pack ice, icebergs and fog. The occurrence of any of these events could result in production shut-ins, the suspension of drilling operations, damage to or destruction of the equipment involved and injury or death of rig personnel. Suncor's offshore operations could also be affected by the actions of Suncor's 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 the company's 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.

- Suncor's Refining and Marketing operations are also 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.

Although the company maintains 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 Suncor operations.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Regulatory Approval and Compliance

Before proceeding with most major projects, including significant changes to existing operations, Suncor must obtain various federal, provincial or state permits and regulatory approvals. Suncor must also obtain licences to operate certain assets. These processes can involve, among other things, stakeholder consultation, environmental impact assessments and public hearings, and may be subject to conditions, including security deposit obligations and other commitments. Suncor can also be indirectly impacted by a third party's inability to obtain regulatory approval for a shared infrastructure project. Compliance can also be affected by the loss of skilled staff, inadequate internal processes and compliance auditing.

As part of ongoing operations, the company is also required to comply with a large number of Environment, Health and Safety regulations under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations. Failure to comply with these regulations may result in the imposition of fines and penalties, production constraints, reputational damage, operating and growth permit applications, censure, liability for cleanup costs and damages, and the loss of important licences and permits.

Failure to obtain, comply with or maintain regulatory permits and approvals, or failure to obtain them on a timely basis or on satisfactory terms, could result in delays, abandonment or restructuring of projects and increased costs, all of which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Project Execution

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.

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, in accordance with design, and at the agreed cost; and
- Commissioning and startup – a failure of the facility to meet agreed performance targets, including operating costs, efficiency, yield and maintenance costs.

Project execution can also be impacted by:

- Failure to comply with Suncor's project implementation model;
- The availability, scheduling and cost of materials, equipment and qualified personnel;
- The complexities associated with integrating and managing contractor staff and suppliers in a confined construction area;
- Our ability to obtain the necessary environmental and other regulatory approvals;
- The impact of general economic, business and market conditions and our ability to finance growth, including major growth projects in progress, if commodity prices were to decline and stay at low levels for an extended period;
- The impact of weather conditions;
- Risks relating to restarting projects placed in safe mode, including increased capital costs;
- The effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment;
- Risk associated with offshore fabrication and logistics;
- Risks relating to scheduling, resources and costs, including the availability and cost of materials, equipment and qualified personnel;
- The accuracy of project cost estimates, as actual costs for major projects can vary from estimates, and these differences can be material;
- Our ability to complete strategic transactions; and

- The commissioning and integration of new facilities within our existing asset base could cause delays in achieving guidance, targets and objectives.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Fossil Fuel Industry Reputation

Suncor works within an environment characterized by concerns over climate change, with environmental limits seen as a legitimate constraint on economic growth and increased activism and public opposition to fossil fuels. In addition, the social value proposition of resource deployment is being challenged.

Future laws and regulations may impose significant liabilities on a failure to comply with their requirements. Concerns over climate change and fossil fuel extraction could lead governments to enact additional or more stringent laws and regulations applicable to Suncor.

Changes in environmental regulation could impact 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.

Climate Change

Suncor continues to actively monitor the international and domestic efforts to address climate change. While it currently appears that GHG regulations and targets will continue to become more stringent, and while Suncor will continue efforts to reduce the intensity of its GHG emissions, the absolute GHG emissions of our company are expected to rise as we pursue a prudent and planned growth strategy. Increases in GHG emissions may impact the profitability of our projects, as Suncor may be subject to incremental levies and taxes.

Land Reclamation

There are risks associated specifically with the company's ability to reclaim 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 the volumes of fluid fine tailings. The inability of TRO$_{TM}$ or any other methods of technology and/or the increase in time to reclaim tailings ponds could increase Suncor's decommissioning and restoration cost estimates.

Alberta's Land-Use Framework

The implementation of, and compliance with, the terms of the Lower Athabasca Regional Plan (LARP) may adversely impact our current properties and projects in northern Alberta due to, among other things, environmental limits and thresholds. Due to the cumulative nature of the plan, the impact of the LARP on Suncor's operations may be outside of the control of the company, as Suncor's operations could be impacted as a result of restrictions imposed due to the cumulative impact of development, by the operators in the area and not solely in relation to Suncor's direct impact.

Alberta Environment Water Licences

We currently rely on fresh water, which is obtained under licences from Alberta Environment, to provide domestic and utility water at our Oil Sands operations. Water licences, like all regulatory approvals, contain conditions to be met in order to maintain compliance with the licence. There can be no assurance that the licences to withdraw water will not be rescinded or that additional conditions will not be added to these licences. There can be no assurance that the company will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of the company's projects may rely on securing licences for additional water withdrawal, and there can be no assurance that these licences will be granted or that they will be granted on terms favourable to Suncor.

There is a risk that future laws or changes to existing laws or regulations could cause capital expenditures and operating expenses to increase or the demand for our products to decrease. There is also a risk that Suncor could face litigation initiated by third parties relating to climate change.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Change Capacity

In order to achieve Suncor's business objectives, the company must operate efficiently, reliably and safely, and, at the same time, deliver growth and sustaining projects safely, on budget and on schedule. The ability to achieve these two sets of objectives is critically important to Suncor to deliver value to shareholders and stakeholders. These objectives also demand a large number of improvement initiatives that compete for resources, and may negatively impact the company should there be inadequate consideration of the cumulative impacts of prior and parallel initiatives on people, processes and systems. There is also a risk that these objectives may exceed Suncor's capacity to adopt and implement change. The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Cost Management

Suncor is exposed to the risk of escalating operating costs in both its Oil Sands business and other businesses. Suncor's inability to successfully manage costs may constrain its ability to execute high-quality projects that deliver lower operating costs. Factors contributing to these risks include, but are not limited to, the skills and resource shortage and the long-term success of existing and new in situ technologies. The risk of escalating operating costs in both its Oil Sands business and other businesses could have

a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Market Access

Suncor anticipates higher production of bitumen in future years, due mainly to production growth from debottlenecking at MacKay River and growth projects at Fort Hills. The markets for bitumen blends or heavy crude are more limited than those for light crude, making them more susceptible to supply and demand changes and imbalances (whether as a result of pipeline constraints or otherwise). Heavy crude oil generally 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, and this price differential can be amplified due to supply and demand imbalances.

There is a risk that constrained market access for oil sands production due to insufficient pipeline takeaway capacity, growing inland production and refinery outages, creates risk of widening differentials that could impact the profitability of product sales which could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Information Security

The efficient operation of Suncor's 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. There is a risk that any significant interruption or the failure of these systems to perform as anticipated for any reason could disrupt our business and could result in decreased performance, production, or increased costs, and could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Financial Risks

Energy Trading and Risk Management Activities and the Exposure to Counterparties

The nature of Suncor's energy trading and risk management activities, which may make use of derivative financial instruments to hedge its commodity price and other market risks, creates exposure to significant financial risks, which include, but are not limited to, the following:

- Unfavourable movements in commodity prices, interest rates or foreign exchange could result in a financial or opportunity loss to the company;
- A lack of counterparties, due to market conditions or other circumstances, could leave us unable to liquidate or offset a position, or unable to do so at or near the previous market price;
- We may not receive funds or instruments from our counterparty at the expected time or at all;
- The counterparty could fail to perform an obligation owed to us;
- Loss as a result of human error or deficiency in our systems or controls; and
- Loss as a result of contracts being unenforceable or transactions being inadequately documented.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Exchange Rate Fluctuations

Our Consolidated Financial Statements are presented in Canadian dollars. The majority of Suncor's revenues from the sale of oil and natural gas are based on prices that are determined by, or referenced to, U.S. dollar benchmark prices, while the majority of Suncor's expenditures are realized in Canadian dollars. The company also holds substantial amounts of U.S. dollar debt. Suncor's results, therefore, can be affected significantly by the exchange rates between the Canadian dollar and the U.S. dollar. The company also undertakes operations administered through international subsidiaries and, so, to a lesser extent, Suncor's results can be affected by the exchange rates between the Canadian dollar and the euro, and the Canadian dollar and the British pound. These exchange rates may vary substantially and may give rise to favourable or unfavourable foreign currency exposure.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Interest Rate Risk

We are exposed to fluctuations in short-term Canadian and U.S. interest rates as Suncor maintains a portion of its debt capacity in revolving and floating rate bank facilities and commercial paper, and invests surplus cash in short-term debt instruments. We are also exposed to interest rate risk when debt instruments are maturing and require refinancing, or when new debt capital needs to be raised. Unfavourable changes in interest rates could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Issuance of Debt and Debt Covenants

Suncor expects that future capital expenditures will be financed out of cash generated from operations and borrowings. This ability is dependent on, among other factors, commodity prices, the overall state of the capital markets and investor appetite for investments in the energy industry generally and our securities in particular. To the extent that external sources of capital become limited or unavailable or available on unfavourable terms, our ability to make capital investments and maintain existing properties may be constrained.

If we finance capital expenditures in whole or in part with debt, that may increase our debt levels above industry standards for oil and gas companies of similar size. Depending on future development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms, including higher interest rates and fees. Neither the articles of Suncor (the Articles) nor its bylaws limit the amount of indebtedness that we may incur; however, we are subject to covenants in our existing bank facilities and seek to avoid an unfavourable cost of debt. The level of our indebtedness, from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise and could negatively affect our credit ratings.

We are required to comply with financial and operating covenants under existing credit facilities and debt securities. We routinely review the covenants based on actual and forecast results and have the ability to make changes to our development plans, capital structure and/or dividend policy to comply with covenants under the credit facilities. If Suncor does not comply with the covenants under its credit facilities and debt securities, there is a risk that repayment could be accelerated and/or the company's access to capital could be restricted or only be available on unfavourable terms.

Rating agencies regularly evaluate the company and our subsidiaries. Their ratings of our long-term and short-term debt are based on a number of factors, including our financial strength, as well as factors not entirely within our control, including conditions affecting the oil and gas industry generally, and the wider state of the economy. Credit ratings may be important to customers or counterparties when we compete in certain markets and when we seek to engage in certain transactions, including transactions involving over-the-counter derivatives. There is a risk that one or more of our credit ratings could be downgraded, which could potentially limit our access to private and public credit markets and increase cost of borrowing.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Other Risk Factors

A detailed discussion of additional risk factors is presented in our most recent Annual Information Form / Form 40-F, filed with the Canadian and U.S. securities regulators, respectively.

11. OTHER ITEMS

Control Environment

Based on their evaluation as of December 31, 2014, Suncor's Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934, as amended (the Exchange Act)), are effective to ensure that information required to be disclosed by the company in reports that are filed or submitted to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2014, there were no changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) that occurred during the year ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Management will continue to periodically evaluate the company's disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

As a result of political unrest in Syria, Suncor is not able to monitor the status of the Syrian assets, including whether certain facilities have suffered damages. Suncor is continually assessing the control environment in Syria to the extent permitted by applicable law and does not consider the changes in the country to have had a material impact on the company's overall internal control over financial reporting.

The effectiveness of our internal control over financial reporting as at December 31, 2014 was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2014.

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

Corporate Guidance

In response to a declining crude price outlook, Suncor issued an update to its 2015 corporate guidance. Suncor's press release dated January 13, 2015, which is also available on suncor.com and sedar.com, provides further details and advisories regarding this update to its corporate guidance.

12. ADVISORIES

Non-GAAP Financial Measures

Certain financial measures in this MD&A – namely operating earnings, ROCE, cash flow from operations, free cash flow, Oil Sands cash operating costs and LIFO – are not prescribed by GAAP. These non-GAAP financial measures are included because management uses the information to analyze business performance, leverage and liquidity. These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. Except as otherwise indicated, these non-GAAP measures are calculated and disclosed on a consistent basis from period to period. Specific adjusting items may only be relevant in certain periods.

Effective January 1, 2013, Suncor adopted new and amended accounting standards; as such, non-GAAP measures for 2012 have been restated while comparative figures pertaining to Suncor's results for 2011 have not been restated in accordance with the respective transitional provisions of the new and amended standards.

Operating Earnings

Operating earnings is a non-GAAP financial measure that adjusts net earnings for significant items that are not indicative of operating performance. Management uses operating earnings to evaluate operating performance, because management believes it provides better comparability between periods. Operating earnings for each segment are reconciled to net earnings in the Financial Information section of the MD&A.

Bridge Analyses of Operating Earnings

Throughout this MD&A, the company presents charts that illustrate the change in operating earnings from the comparative period through key variance factors. These factors are analyzed in the Operating Earnings narratives following the bridge analyses in that particular section of the MD&A. These bridge analyses are presented because management uses this presentation to analyze performance.

- The factor for Volumes and Mix is calculated based on production volumes and mix for the Oil Sands and Exploration and Production segments and throughput volumes and mix for the Refining and Marketing segment.
- The factor for Price, Margin and Other Revenue includes upstream price realizations before royalties, refining and marketing margins, other operating revenues, and the net impacts of sales and purchases of third-party crude, including product purchased for use as diluent in the company's Oil Sands operations and subsequently sold as part of diluted bitumen.
- The factor for Royalties includes royalties in Libya that represent the difference between gross revenues, which is based on the company's working-interest share of production, and the net revenue attributable to Suncor under the terms of the respective contracts.
- The factor for Inventory reflects the opportunity cost of building production volumes in inventory or the additional margin earned by drawing down inventory produced in previous periods. The calculation of the Inventory factor in a bridge analysis permits the company to present the factor for Volumes and Mix based on production volumes, rather than based on sales volumes.
- The factor for Operating and Transportation Expense includes project startup costs, operating, selling and general expense (adjusted for impacts of changes in inventory), and transportation expense.
- The factor for Financing Expense and Other Income includes financing expenses, other income, operational foreign exchange gains and losses, changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in statutory income tax rates, and other income tax adjustments.

Return on Capital Employed (ROCE)

ROCE is a non-GAAP financial measure that management uses to analyze operating performance and the efficiency of Suncor's capital allocation process. Average capital employed is calculated as a twelve-month average of the capital employed balance at the beginning of the twelve-month period and the month-end capital employed balances throughout the remainder of the twelve-month period. Figures for capital employed at the beginning and end of the

twelve-month period are presented to show the changes in the components of the calculation over the twelve-month period.

The company presents two ROCE calculations – one including and one excluding the impacts on capital employed of major projects in progress. Major projects in progress includes accumulated capital expenditures and capitalized interest for significant projects still under construction or in the process of being commissioned, and acquired assets that are still being evaluated. Management uses ROCE excluding the impacts of major projects in progress on capital employed to assess performance of operating assets.

Year ended December 31 ($ millions, except as noted)		**2014**	2013	2012
Adjustments to net earnings				
Net earnings		**2 699**	3 911	2 740
Add after-tax amounts for:				
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt		**722**	521	(157)
Net interest expense		**229**	228	42
	A	**3 650**	4 660	2 625
Capital employed – beginning of twelve-month period				
Net debt		**6 256**	6 639	6 976
Shareholders' equity		**41 180**	39 215	38 592
		47 436	45 854	45 568
Capital employed – end of twelve-month period				
Net debt		**7 834**	6 256	6 639
Shareholders' equity		**41 603**	41 180	39 215
		49 437	47 436	45 854
Average capital employed	B	**48 797**	46 981	45 353
ROCE – including major projects in progress (%)	A/B	**7.5**	9.9	5.8
Average capitalized costs related to major projects in progress	C	**6 203**	6 502	8 729
ROCE – excluding major projects in progress (%)	A/(B-C)	**8.6**	11.5	7.2

Cash Flow from Operations and Free Cash Flow

Cash flow from operations is a non-GAAP financial measure that adjusts a GAAP measure – cash flow provided by operating activities – for changes in non-cash working capital, which management uses to analyze operating performance and liquidity. Changes to non-cash working capital can include, among other factors, the timing of offshore feedstock purchases and payments for fuel and income taxes, which management believes reduces comparability between periods.

	Oil Sands			Exploration and Production			Refining and Marketing		
Year ended December 31 ($ millions)	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Net earnings (loss)	**1 776**	2 040	468	**653**	1 000	138	**1 692**	2 022	2 137
Adjustments for:									
Depreciation, depletion, amortization and impairment	**4 035**	2 439	3 964	**1 349**	1 804	1 857	**635**	530	464
Deferred income taxes	**(139)**	358	266	**(115)**	(130)	28	**(43)**	64	529
Accretion of liabilities	**140**	114	109	**44**	60	62	**7**	6	4
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of derivative contracts	**(34)**	—	—	**—**	—	—	**(82)**	1	(1)
Loss (gain) on disposal of assets	**3**	—	(29)	**(82)**	(130)	(1)	**(11)**	(7)	(13)
Share-based compensation	**22**	7	95	**8**	28	14	**4**	19	48
Exploration expenses	**—**	—	—	**104**	82	145	**—**	—	—
Settlement of decommissioning and restoration liabilities	**(324)**	(388)	(380)	**(20)**	(15)	(32)	**(20)**	(20)	(21)
Other	**(79)**	(14)	(86)	**(32)**	(383)	16	**(4)**	3	(9)
Cash flow from (used in) operations	**5 400**	4 556	4 407	**1 909**	2 316	2 227	**2 178**	2 618	3 138
Decrease (increase) in non-cash working capital	**1 252**	1 225	(781)	**201**	656	(205)	**(278)**	566	(460)
Cash flow provided by (used in) operating activities	**6 652**	5 781	3 626	**2 110**	2 972	2 022	**1 900**	3 184	2 678

Year ended December 31 ($ millions)	Corporate, Energy Trading and Eliminations			Total		
	2014	2013	2012	**2014**	2013	2012
Net (loss) earnings	**(1 422)**	(1 151)	(3)	**2 699**	3 911	2 740
Adjustments for:						
Depreciation, depletion, amortization and impairment	**121**	119	161	**6 140**	4 892	6 446
Deferred income taxes	**73**	90	(94)	**(224)**	382	729
Accretion of liabilities	**7**	12	7	**198**	192	182
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**839**	605	(181)	**839**	605	(181)
Change in fair value of derivative contracts	**(154)**	94	11	**(270)**	95	10
Gain on disposal of assets	**—**	—	(1)	**(90)**	(137)	(44)
Share-based compensation	**72**	160	57	**106**	214	214
Exploration expenses	**—**	—	—	**104**	82	145
Settlement of decommissioning and restoration liabilities	**—**	—	—	**(364)**	(423)	(433)
Other	**35**	(7)	4	**(80)**	(401)	(75)
Cash flow (used in) from operations	**(429)**	(78)	(39)	**9 058**	9 412	9 733
(Increase) decrease in non-cash working capital	**(1 297)**	(1 759)	572	**(122)**	688	(874)
Cash flow (used in) provided by operating activities	**(1 726)**	(1 837)	533	**8 936**	10 100	8 859

Free cash flow is a non-GAAP financial measure that is calculated by deducting capital and exploration expenditures from cash flow from operations. Free cash flow reflects cash available for distribution to shareholders and to fund financing activities. Management uses free cash flow to measure financial performance and liquidity. The following is a reconciliation of free cash flow for Suncor's last three years of operations.

($ millions)	**2014**	2013	2012
Cash flow from operations	**9 058**	9 412	9 733
Capital and exploration expenditures	**(6 961)**	(6 777)	(6 957)
Free Cash Flow	**2 097**	2 635	2 776

Oil Sands Cash Operating Costs

Oil Sands cash operating costs and cash operating costs per barrel are non-GAAP financial measures, which are calculated by adjusting Oil Sands segment operating, selling and general expense (a GAAP measure based on sales volumes) for i) costs pertaining to Syncrude operations; ii) non-production costs that management believes do not relate to the production performance of Oil Sands operations, including, but not limited to, share-based compensation adjustments, costs related to the remobilization or deferral of growth projects, research, the expense recorded as part of a non-monetary arrangement involving a third-party processor, and feedstock costs for natural gas used to create hydrogen for secondary upgrading processes; iii) revenues associated with excess capacity, including excess power generated and sold that is recorded in operating revenue; and iv) the impacts of changes in inventory levels, such that the company is able to present cost information based on production volumes.

Impact of First-in, First-out Inventory Valuation on Refining and Marketing Net Earnings

GAAP requires the use of a FIFO valuation methodology. For Suncor, this results in a lag between the sales prices for refined products, which reflects current market conditions, and the amount recorded as the cost of sale for the related refinery feedstock, which reflects market conditions at the time when the feedstock was purchased.

Suncor prepares and presents an estimate of the impact of using a FIFO inventory valuation methodology compared to a LIFO methodology, because management uses the information to analyze operating performance and compare itself against refining peers that are permitted to use LIFO inventory valuation under United States GAAP (U.S. GAAP).

The company's estimate is not derived from a standardized calculation and, therefore, may not be directly comparable to similar measures presented by other companies, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP or U.S. GAAP.

Measurement Conversions

Certain crude oil and natural gas liquids volumes have been converted to mcfe or mmcfe on the basis of one bbl to six mcf. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Any figure presented in mcfe, mmcfe, boe or mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or natural gas liquids 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, conversion on a 6:1 basis may be misleading as an indication of value.

Operating Earnings Reconciliations – Fourth Quarter 2014 and 2013

Three months ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Net earnings (loss) as reported	**180**	469	**198**	(101)	**173**	458	**(467)**	(383)	**84**	443
Unrealized foreign exchange loss on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**302**	259	**302**	259
Net impact of not proceeding with the Voyageur upgrader project	**—**	(69)	**—**	—	**—**	—	**—**	—	**—**	(69)
Impairments (net of reversals) and provisions	**—**	—	**—**	563	**—**	—	**—**	—	**—**	563
Recognition of risk mitigation proceeds	**—**	—	**—**	(223)	**—**	—	**—**	—	**—**	(223)
Operating earnings (loss)	**180**	400	**198**	239	**173**	458	**(165)**	(124)	**386**	973

Cash Flow from Operations Reconciliations – Fourth Quarter 2014 and 2013

Three months ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Net earnings (loss)	**180**	469	**198**	(101)	**173**	458	**(467)**	(383)	**84**	443
Adjustments for:										
Depreciation, depletion, amortization and impairment	**709**	680	**297**	915	**162**	149	**32**	31	**1 200**	1 775
Deferred income taxes	**84**	35	**(83)**	—	**(10)**	(84)	**60**	41	**51**	(8)
Accretion of liabilities	**34**	30	**11**	10	**2**	2	**—**	2	**47**	44
Unrealized foreign exchange loss on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**352**	304	**352**	304
Change in fair value of derivative contracts	**(32)**	1	**(2)**	1	**(68)**	2	**(54)**	154	**(156)**	158
Gain on disposal of assets	**—**	—	**—**	—	**(10)**	(3)	**—**	—	**(10)**	(3)
Share-based compensation	**(5)**	17	**(1)**	7	**(2)**	10	**(4)**	47	**(12)**	81
Exploration expenses	**—**	—	**8**	23	**—**	—	**—**	—	**8**	23
Settlement of decommissioning and restoration liabilities	**(70)**	(75)	**(3)**	1	**(10)**	(7)	**—**	—	**(83)**	(81)
Other	**(25)**	(47)	**(24)**	(304)	**3**	7	**57**	(42)	**11**	(386)
Cash flow from (used in) operations	**875**	1 110	**401**	552	**240**	534	**(24)**	154	**1 492**	2 350
Decrease (increase) in non-cash working capital	**1 542**	(963)	**137**	91	**317**	340	**(1 473)**	518	**523**	(14)
Cash flow provided by (used in) operating activities	**2 417**	147	**538**	643	**557**	874	**(1 497)**	672	**2 015**	2 336

Common Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

Measurement

bbl	barrel
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcf/d	millions of cubic feet of natural gas per day
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
m^3	cubic metres
MW	Megawatts
MWh	Megawatt hour

Places and Currencies

U.S.	United States
U.K.	United Kingdom
B.C.	British Columbia
$ or Cdn$	Canadian dollars
US$	United States dollars
£	Pounds sterling
€	Euros

Financial and Business Environment

DD&A	Depreciation, depletion and amortization
WTI	West Texas Intermediate
WCS	Western Canadian Select
SCO	Synthetic crude oil

Forward-Looking Information

The MD&A contains certain forward-looking statements and forward-looking information (collectively, forward-looking statements) within the meaning of applicable Canadian and U.S. securities laws and other information based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of information available at the time the statement was made and consider Suncor's experience and its perception of historical trends, including expectations and assumptions concerning: the accuracy of reserves and resources estimates; commodity prices and interest and foreign exchange rates; capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and third-party approvals. In addition, all other statements and other information that address expectations or projections about the future, and other statements and information about Suncor's strategy for growth, expected and future expenditures or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and the expected impact of future commitments are forward- looking statements. Some of the forward-looking statements and information may be identified by words like "expects", "anticipates", "will", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", "continue", "should", "may", "aiming" and similar expressions.

Forward-looking statements in this MD&A include references to:

Suncor's expectations about production volumes and the performance and costs of its assets, including that:

- *The Fort Hills mining project will be developed using traditional open-pit truck and shovel techniques, and solvent-based extraction technology that will allow the mine to produce a bitumen product that can be sold directly to market. The project is scheduled to produce first oil as early as the fourth quarter of 2017 with a ramp up to 90% of its planned gross production capacity of 180,000 bbls/d (73,400 bbls/d net to Suncor) within twelve months. Project activities in 2015 are expected to focus on the completion of detailed engineering on the secondary extraction and utilities areas, the continued ramp up of procurement spending, and field construction activities across all areas. Suncor's share of the estimated post-sanction project cost is $5.5 billion;*

- *Golden Eagle is expected to reach peak production of approximately 18,000 boe/d (net to Suncor) in 2015. The field development plan for*

Golden Eagle includes stand-alone facilities designed for 70,000 boe/d of gross production capacity. Activity in 2015 will include further development drilling as production ramps up to its peak production rate. Suncor's share of the post-sanction costs is estimated at $1 billion (+/-10%);

- *Suncor has a target to increase upgrader reliability to a 90% utilization rate of 315,000 bbls/d by 2017;*
- *The Hebron field includes a gravity-based structure design supporting a gross oil production rate of*

150,000 bbls/d (34,200 boe/d net to Suncor). Project activity in 2015 is expected to focus on construction of the gravity-based structure and topsides. Suncor's share of the estimated project cost is $2.8 billion (+/-10%). First oil at the Hebron project is expected in 2017; and

- *Cedar Point, which is expected to commence operations by the end of 2015, and Adelaide, both based in Ontario, are expected to add 140 MW of gross installed capacity, increasing the capacity of Suncor's wind projects by 55%.*

The anticipated duration and impact of planned maintenance events, including that:

- *There are no major turnarounds scheduled for 2015 in Oil Sands. The company plans to complete routine maintenance on two coker units throughout the year;*
- *A planned ten-week maintenance event at Terra Nova has been scheduled for the second quarter of 2015; and*
- *The company has scheduled planned maintenance events at the Commerce City refinery in the first quarter of 2015 with an expected duration of four weeks. The Edmonton refinery has a five-week planned maintenance event in the second quarter of 2015. The Sarnia refinery has a two-week planned maintenance event in the second quarter of 2015. The Montreal refinery has a one-week planned maintenance event in the third quarter of 2015 as well as a three-week planned maintenance event in the fourth quarter of 2015.*

Suncor's expectations about capital expenditures, and growth and other projects, including:

- *The HSEU's production is expected to ramp up in the last half of 2015. Drilling is expected to continue in 2015 with first oil at SWRX expected in the second quarter of 2015. The HSEU and SWRX projects are expected to provide incremental production and extend the productive life of the existing fields;*
- *The fourth appraisal well is planned for the Beta project in 2015, while further evaluation activities are expected to continue on the Butch prospect in 2015;*
- *Suncor expects to drill at six exploration locations in the North Sea and on the east coast of Canada in 2015 (two operated by Suncor);*
- *Suncor reached an agreement to sell the company's 50% interest in certain assets and liabilities of Pioneer Energy for $182.5 million, before adjustments and other costs, which is expected to close in the first half of 2015;*
- *The sulphur recovery facility integrated into the Montreal refinery is expected to secure the refinery's long-term sulphur recovery needs and improve overall production yields;*
- *The company's operational excellence initiatives, including debottlenecking and infill drilling programs at both Firebag and MacKay River, are expected to achieve steady production growth while reducing operating costs;*
- *For 2015, Oil Sands operations plans for sustaining capital continue to focus on planned maintenance, tailings management operations offsetting natural production declines, and maintaining production capacity of existing facilities, including new well pads for In Situ assets and equipment replacement for the mine;*
- *The company's plans for growth capital for Oil Sands operations in 2015 include continuing construction of midstream assets that will support production, including hot bitumen cooling and blending facilities, and related storage assets;*
- *Oil Sands ventures sustaining capital expenditures in 2015 for Syncrude are expected to focus on planned maintenance, development of tailings management facilities, improvements to utilities facilities and capital to complete mine train replacements;*
- *Sustaining capital for Refining and Marketing will focus on planned maintenance events and routine asset replacement;*
- *Growth capital for renewable energy will be focused on progressing projects within the company's renewable business including the Cedar Point project. Construction of the Cedar Point project is expected to be completed and commercial operations are expected to begin later in 2015. The project is expected to add 100 MW of gross installed capacity. The final decision on an appeal of the company's permit for the Cedar Point project is expected in early March 2015. Suncor has also invested in biodiesel technology to capture a production cost advantage, through interests in both a technology company and the retrofit of a biodiesel plant, which is expected to be completed by the end of 2015; and*
- *The focus for the ethanol operations will be to maintain safe and reliable operations and improve plant profitability through technology improvements.*

Also:

- *Suncor's strategies and commitment to delivering competitive and sustainable returns to shareholders by focusing on capital discipline, operational excellence and long-term profitable growth, and by leveraging its competitive differentiators;*

- *Suncor's projects, such as Fort Hills, are expected to provide long-term profitability for the company;*
- *Suncor's expectation that it will drive down costs and focus on improved productivity and reliability, which is expected to help Suncor get the most out of its operations;*
- *The company's reductions in its 2015 capital program of $1 billion, including the deferral of some projects that have not been sanctioned, which is not expected to impact the company's continued safety, reliability and environmental performance;*
- *Suncor's $600 million to $800 million targeted reduction in operating costs;*
- *The anticipated reversal of Enbridge's Line 9, combined with existing rail access, is expected to provide the company with the flexibility to supply the Montreal refinery with a full slate of inland priced crude in the latter part of 2015;*
- *Suncor's construction of a water treatment plant that is expected to reduce freshwater use;*
- *The company's belief that it does not have any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources;*
- *Suncor's management believes the company will have the capital resources to fund its planned 2015 capital spending program of $6.2 to $6.8 billion and meet working capital requirements through existing cash balances and short-term investments, cash flow from operations, available committed credit facilities, issuing commercial paper and issuing long-term notes or debentures;*
- *If additional capital is required, the company believes additional financing will be available at commercial terms and rates; and*
- *Our belief that a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels.*

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

The financial and operating performance of the company's reportable operating segments, specifically Oil Sands, Exploration and Production, and Refining and Marketing, may be affected by a number of factors.

Factors that affect our Oil Sands segment include, but are not limited to, volatility in the prices for crude oil and other production, and the related impacts of fluctuating light/heavy and sweet/sour crude oil differentials; changes in the demand for refinery feedstock and diesel fuel, including the possibility that refiners that process our proprietary production will be closed, experience equipment failure or other accidents; our ability to operate our Oil Sands facilities reliably in order to meet production targets; the output of newly commissioned facilities, the performance of which may be difficult to predict during initial operations; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; our dependence on pipeline capacity and other logistical constraints, which may affect our ability to distribute our products to market; our ability to finance Oil Sands growth and sustaining capital expenditures; the availability of bitumen feedstock for upgrading operations, which can be negatively affected by poor ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage, and in situ reservoir and equipment performance, or the unavailability of third-party bitumen; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; our ability to complete projects, including planned maintenance events, both on time and on budget, which could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Alberta's Wood Buffalo region and the surrounding area (including housing, roads and schools); risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; changes to royalty and tax legislation and related agreements that could impact our business; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and changes to environmental regulations or legislation.

Factors that affect our Exploration and Production segment include, but are not limited to, volatility in crude oil and natural gas prices; operational risks and uncertainties associated with oil and gas activities, including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, and pollution and other environmental risks; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; adverse weather conditions, which could disrupt output from producing assets or impact drilling programs,

resulting in increased costs and/or delays in bringing on new production; political, economic and socio-economic risks associated with Suncor's foreign operations, including the unpredictability of operating in Libya and that operations in Syria continue to be impacted by sanctions or political unrest; risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and market demand for mineral rights and producing properties, potentially leading to losses on disposition or increased property acquisition costs.

Factors that affect our Refining and Marketing segment include, but are not limited to, fluctuations in demand and supply for refined products that impact the company's margins; market competition, including potential new market entrants; our ability to reliably operate refining and marketing facilities in order to meet production or sales targets; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; risks and uncertainties affecting construction or planned maintenance schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period; and the potential for disruptions to operations and construction projects as a result of our relationships with labour unions or employee associations that represent employees at our refineries and distribution facilities.

Additional risks, uncertainties and other factors that could influence the financial and operating performance of all of Suncor's operating segments and activities include, but are not limited to, changes in general economic, market and business conditions, such as commodity prices, interest rates and currency exchange rates; fluctuations in supply and demand for Suncor's products; the successful and timely implementation of capital projects, including growth projects and regulatory projects; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; actions by government authorities, including the imposition or reassessment of taxes or changes to fees and royalties, such as the NORs received by Suncor from the CRA, Ontario, Alberta and Quebec, relating to the settlement of certain derivative contracts, including the risk that: (i) Suncor may not be able to successfully defend its original filing position and ultimately be required to pay increased taxes, interest and penalty as a result; or (ii) Suncor may be required to post cash instead of security in relation to the NORs; changes in environmental and other regulations; the ability and willingness of parties with whom we have material relationships to perform their obligations to us; outages to third-party infrastructure that could cause disruptions to production; the occurrence of unexpected events such as fires, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; the potential for security breaches of Suncor's information systems by computer hackers or cyberterrorists, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; our ability to find new oil and gas reserves that can be developed economically; the accuracy of Suncor's reserves, resources and future production estimates; market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; maintaining an optimal debt to cash flow ratio; the success of the company's risk management activities using derivatives and other financial instruments; the cost of compliance with current and future environmental laws; risks and uncertainties associated with closing a transaction for the purchase or sale of an oil and gas property, including estimates of the final consideration to be paid or received, the ability of counterparties to comply with their obligations in a timely manner and the receipt of any required regulatory or other third-party approvals outside of Suncor's control that are customary to transactions of this nature; and the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering that is needed to reduce the margin of error and increase the level of accuracy. The foregoing important factors are not exhaustive.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout this MD&A, including under the heading Risk Factors, and the company's 2014 AIF dated February 26, 2015 and Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

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EXHIBIT 99-2

Management's Discussion and Analysis for the fiscal year ended December 31, 2014, dated February 26, 2015

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EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

CONSENT OF INDEPENDENT AUDITOR

We hereby consent to inclusion in this Annual Report on Form 40-F for the year ended December 31, 2014 and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-10 (File No. 333-196501) of Suncor Energy Inc., of our report dated February 24, 2015 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in the Annual Report.

We also consent to reference to us under the heading "Interests of Experts" in the Annual Information Form incorporated by reference in this Annual Report on Form 40-F which is incorporated by reference in the Registration Statements referred to above.

"PricewaterhouseCoopers LLP"
Chartered Accountants
Calgary, Alberta
February 26, 2015

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EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

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EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces and Territories of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the following reports (the "**Reports**") prepared by GLJ Petroleum Consultants Ltd. ("**GLJ**"):

- Reserves Assessment and Evaluation of In Situ Oil Sands Properties dated February 20, 2015 — Summary; and
- Reserves Evaluation and Resources Assessment of Oil Sands Mining Properties dated February 20, 2015 — Summary,

which provide GLJ's reports on proved and probable reserves evaluations and assessment of contingent resource pursuant to Canadian disclosure requirements of Suncor Energy Inc.'s Canadian mining and in-situ leases that were evaluated as at December 31, 2014.

We hereby consent to being named and to the use of, reference to and excerpts and information derived from the said Reports by Suncor Energy Inc. in its:

1. Annual Report on Form 40-F for the year ended December 31, 2014 (the " **Form 40-F**") and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-10 (File No. 333-196501) of Suncor Energy Inc., of our Reports;
2. Annual Report for the year ended December 31, 2014 (the " **Annual Report**") to be filed with the securities regulatory authorities of each of the provinces of Canada; and
3. Annual Information Form dated February 26, 2015 (the "**AIF**"), which is incorporated by reference into the following prospectuses (collectively, the "**Prospectuses**"): (i) the short form base shelf prospectus of Suncor dated June 11, 2014 relating to the sale and issue of debt securities from time to time in the aggregate principal amount of U.S. $2,000,000,000, and (ii) the short form base shelf prospectus of Suncor dated June 11, 2014 relating to the sale and issue of Series 5 medium term notes, from time to time, in the aggregate principal amount of up to CDN $2,000,000,000.

We have read the Form 40-F, Annual Report, AIF and Prospectuses and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the Reports.

Yours very truly,

GLJ PETROLEUM CONSULTANTS LTD.

"GLJ Petroleum Consultants Ltd."

Caralyn P. Bennett, P. Eng.
Vice President

Dated: February 26, 2015
Calgary, Alberta
CANADA

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EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.
LETTER OF CONSENT

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EXHIBIT 99-5

Consent of Sproule Associates Limited, Sproule Unconventional Limited and Sproule International Limited

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces and Territories of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the following reports (the "**Reports**") prepared by Sproule Associates Limited, Sproule Unconventional Limited and Sproule International Limited:

- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the Newfoundland Offshore Areas dated February 20, 2015;
- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the North America Onshore Properties dated February 20, 2015;
- Evaluation of the P&NG Resources of Suncor Energy Inc. in the Montney Formation, Kobes Area, British Columbia dated February 20, 2015;
- Evaluation of the P&NG Reserves of Suncor Energy Inc., North Sea Properties dated February 20, 2015;
- Evaluation of the P&NG Reserves of Suncor Energy Inc., Libya Properties dated February 20, 2015; and
- Evaluation of the P&NG Reserves of Suncor Energy Inc., Other International Properties, Volume 3 — Ash Shaer Field, Syria dated February 16, 2012 ("**Syria Reserves Assessment**").

which provide our reports on proved and probable reserves evaluations and assessment of contingent resources pursuant to Canadian disclosure requirements of Suncor Energy Inc.'s Canadian onshore and offshore conventional assets and international operations that were evaluated as at December 31, 2014, except in the case of the Syria Reserves Assessment, which is as at December 31, 2011.

We hereby consent to being named and to the use of, reference to and excerpts and information derived from the said Reports by Suncor Energy Inc. in its:

1. Annual Report on Form 40-F for the year ended December 31, 2014 (the " **Form 40-F**") and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-10 (File No. 333-196501) of Suncor Energy Inc., of our Reports;

2. Annual Report for the year ended December 31, 2014 (the " **Annual Report**") to be filed with the securities regulatory authorities of each of the provinces of Canada; and

3. Annual Information Form dated February 26, 2015 (the "**AIF**"), which is incorporated by reference into the following prospectuses (collectively, the "**Prospectuses**"): (i) the short form base shelf prospectus of Suncor dated June 11, 2014 relating to the sale and issue of debt securities from time to time in the aggregate principal amount of U.S. $2,000,000,000, and (ii) the short form base shelf prospectus of Suncor dated June 11, 2014 relating to the sale and issue of Series 5 medium term notes, from time to time, in the aggregate principal amount of up to CDN $2,000,000,000.

We have read the Form 40-F, Annual Report, AIF and Prospectuses and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the Reports.

Sincerely,

Sproule Associates Limited,
Sproule Unconventional Limited and
Sproule International Limited

"Sproule Associates Limited",
"Sproule Unconventional Limited" and
"Sproule International Limited"

Harry J. Helwerda, P.Eng., FEC, FGC (Hon.)
President and Director

Dated: February 26, 2015
Calgary, Alberta, Canada

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EXHIBIT 99-5

Consent of Sproule Associates Limited, Sproule Unconventional Limited and Sproule International Limited
LETTER OF CONSENT

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EXHIBIT 99-6

CERTIFICATION

I, Steven W. Williams, certify that:

1. I have reviewed this annual report on Form 40-F of Suncor Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ STEVEN W. WILLIAMS

Steven W. Williams
President and Chief Executive Officer

DATE: February 26, 2015

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EXHIBIT 99-6

CERTIFICATION

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EXHIBIT 99-7

CERTIFICATION

I, Alister Cowan, certify that:

1. I have reviewed this annual report on Form 40-F of Suncor Energy Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ ALISTER COWAN

Alister Cowan
Executive Vice President and Chief Financial Officer

DATE: February 26, 2015

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EXHIBIT 99-7

CERTIFICATION

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EXHIBIT 99-8

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, STEVEN W. WILLIAMS, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ STEVEN W. WILLIAMS

Steven W. Williams
President and Chief Executive Officer
Suncor Energy Inc.

DATE: February 26, 2015

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EXHIBIT 99-8

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

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EXHIBIT 99-9

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, ALISTER COWAN, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ ALISTER COWAN

Alister Cowan
Executive Vice President and Chief Financial Officer
Suncor Energy Inc.

DATE: February 26, 2015

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EXHIBIT 99-9

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

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EXHIBIT 99-10

SUPPLEMENTARY OIL AND GAS DISCLOSURES (unaudited)

The following disclosures are presented in accordance with United States Financial Accounting Standards Board ("FASB") Topic 932 — "Extractive Activities — Oil and Gas" and Subpart 1200 of Regulation S-K ("Subpart 1200") promulgated by the United States Securities and Exchange Commission. Disclosures pertaining to the audited consolidated financial statements as at and for the year ended December 31, 2014 (the "2014 Financial Statements") of Suncor Energy Inc. ("Suncor" or the "Company") were prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and Canadian generally accepted accounting principles contained within Part 1 of the Chartered Professional Accountants Canada Handbook, which differ in material respects from financial statements prepared in accordance with United States generally accepted accounting principles. The 2014 Financial Statements are attached as Exhibit 99.1 to Suncor's annual report on Form 40-F for the year ended December 31, 2014 (the "Form 40-F").

Reserves Data

Reserve estimates included herein are estimates only and can be significantly impacted by a variety of internal and external factors. For more information to the risks involved when estimating reserves, see the discussion in the "Statement of Reserves Data and Other Oil and Gas Information — Significant Risk Factors and Uncertainties Affecting Reserves Data" section in Suncor's 2014 Annual Information Form (the "2014 AIF"), which is contained in the Form 40-F. Readers should also see Suncor's Management's Discussion and Analysis for the year ended December 31, 2014, which is attached as Exhibit 99.2 to the Form 40-F (the "2014 Management's Discussion and Analysis").

The reserve data presented herein may differ in relation to the format and the basis from which volumes are economically determined under Subpart 1200 and National Instrument 51-101 — "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), as disclosed in the 2014 AIF. Subpart 1200 requires disclosure of net proved reserves, after royalties, using the average of the first-day-of-the-month prices for the twelve month period prior to the end of the reporting period, whereas NI 51-101 requires disclosure of gross and net reserves, estimated using forecast prices and costs.

Net Proved Oil and Gas Reserves [1][2]

The majority of Suncor's oil and gas reserves are in Canada. In order to align with the Company's segmented information in the 2014 Financial Statements, the 2014 Management's Discussion and Analysis and the 2014 AIF, the Company presents the following supplementary oil and gas disclosures by showing amounts associated with its Oil Sands segment, which are exclusively in Canada and produce synthetic crude oil ("SCO") and bitumen, separate from other Canadian operations, which are

aggregated with Suncor's international operations (collectively, "Exploration and Production") and produce crude oil, natural gas and natural gas liquids ("NGLs").

At December 31, (net reserves, constant prices and costs)	SCO (mmbbls)		Bitumen (mmbbls)		Crude Oil and NGLs[3] (mmbbls)		Natural Gas (bcf)		Total (mmboe)	
	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013
Proved Developed										
Oil Sands	1 700	1 804	143	153	—	—	—	—	1 843	1 957
Exploration and Production	—	—	—	—	170	171	36	38	176	177
	1 700	1 804	143	153	170	171	36	38	2 019	2 134
Proved Undeveloped										
Oil Sands	452	516	1 444	1 566	—	—	—	—	1 897	2 082
Exploration and Production	—	—	—	—	64	46	1	6	64	47
	452	516	1 444	1 566	64	46	1	6	1 961	2 129
Proved										
Oil Sands	2 152	2 320	1 588	1 719	—	—	—	—	3 740	4 040
Exploration and Production	—	—	—	—	234	216	37	44	241	223
	2 152	2 320	1 588	1 719	234	216	37	44	3 981	4 263

Reconciliation of Net Proved Oil and Gas Reserves

(net reserves, constant prices and costs)	Balance December 31 2012	Revisions of Previous Estimates[4]	Improved Recovery	Acquisitions	Extensions and Discoveries[5]	Production	Dispositions	Balance December 31 2013
Oil Sands								
SCO (mmbbls)	2 333	30	1	—	69	(112)	—	2 320
Bitumen (mmbbls)	885	1	1	—	856	(23)	—	1 719
Exploration and Production								
Crude oil and NGLs[3] (mmbbls)	251	12	—	—	2	(37)	(12)	216
Natural gas (bcf)	546	10	—	—	6	(61)	(457)	44
Total (mmboe)	3 560	45	2	—	928	(182)	(89)	4 263

(net reserves, constant prices and costs)	Balance December 31 2013	Revisions of Previous Estimates[4]	Improved Recovery	Acquisitions	Extensions and Discoveries[5]	Production	Dispositions	Balance December 31 2014
Oil Sands								
SCO (mmbbls)	2 320	(62)	—	—	—	(106)	—	2 152
Bitumen (mmbbls)	1 719	(92)	—	—	—	(39)	—	1 588
Exploration and Production								
Crude oil and NGLs[3] (mmbbls)	216	53	—	—	1	(32)	(4)	234
Natural gas (bcf)	44	8	—	—	6	(7)	(14)	37
Total (mmboe)	4 263	(100)	—	—	2	(178)	(6)	3 981

Notes to Reserve Data:

(1) Definitions

a. Net reserves, in relation to Suncor's production and reserves, represents the Company's working interest (operated and non-operated) share after deduction of royalty obligations, plus the Company's royalty interests in production and reserves.

b. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations.

c. Proved developed oil and gas reserves are those quantities that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and can be expected to be recovered through extraction equipment and

infrastructure installed and operational at the time of the reserves estimate for projects that extract oil and gas by means not involving a well.

d. Proved undeveloped oil and gas reserves are those quantities that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) Reserve data tables may not add due to rounding.

(3) Natural gas liquids reserves are not significant and have been presented in combination with Crude Oil reserves.

(4) Revisions of previous estimates include changes to proved reserves, either upward or downward, resulting from new information (except for an increase in proved acreage) normally obtained from development drilling and production history or resulting from a change in economic factors, such as changes in constant prices used for the reserve evaluation.

(5) Extensions and discoveries are additions to proved reserves from proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery or discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. The change in Oil Sands for 2013 was driven primarily by the addition of reserves as a result of the Fort Hills project sanction in October of 2013.

Capitalized Costs

	At December 31, 2014			At December 31, 2013		
($ millions)	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Exploration and evaluation assets[1]	1 581	667	2 248	2 040	732	2 772
Oil and gas properties[2]	12 584	16 651	29 235	10 770	14 753	25 523
Plant and equipment[2]	41 427	1 016	42 443	41 357	907	42 264
— accumulated provision[2]	(13 032)	(8 021)	(21 053)	(12 124)	(6 704)	(18 828)
Total	42 560	10 313	52 873	42 043	9 688	51 731

(1) Exploration and evaluation assets largely represent amounts associated with unproved properties, but may include properties with proved reserves for which Suncor's Board of Directors have not sanctioned development. See note 18 of the 2014 Financial Statements.

(2) Oil and Gas Properties, Plant and Equipment and the accumulated provision largely represent amounts associated with proved properties. See note 17 of the 2014 Financial Statements.

Costs Incurred for Property Acquisition, Exploration and Development Activities

	Year ended December 31, 2014			Year ended December 31, 2013		
($ millions)	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Unproved property acquisition	—	1	1	—	2	2
Proved property acquisition	—	—	—	—	—	—
Exploration[1]	161	296	457	196	308	504
Development[2]	4 237	1 819	6 056	4 322	1 247	5 569
Total	4 398	2 116	6 514	4 518	1 557	6 075

(1) Includes amounts capitalized to Exploration and Evaluation as well as those charged to Exploration Expense on the Consolidated Balance Sheets and the Consolidated Statements of Comprehensive Income, respectively, of the 2014 Financial Statements.

(2) Includes amounts capitalized to Property, Plant and Equipment on the Consolidated Balance Sheets of the 2014 Financial Statements that relate to the Company's decommissioning and restoration activities.

Results of Operations for Oil- and Gas-Producing Activities

($ millions)	At December 31, 2014			At December 31, 2013		
	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Operating revenues, net of royalties	13 579	4 043	17 622	12 230	5 217	17 447
Other Income	115	217	332	64	381	445
	13 694	4 260	17 954	12 294	5 598	17 892
Purchases of crude oil and products	355	459	814	460	568	1 028
Operating, selling and general	6 042	558	6 600	5 852	676	6 528
Transportation	541	90	631	482	127	609
Depreciation, depletion, amortization and impairment	4 035	1 349	5 384	2 439	1 804	4 243
Exploration	96	271	367	115	207	322
Gain (loss) on disposal of assets	3	(82)	(79)	—	(130)	(130)
Voyageur upgrader project charges	—	—	—	82	—	82
Finance expenses	153	72	225	135	33	168
Earnings before Income Taxes	2 469	1 543	4 012	2 729	2 313	5 042
Income taxes	693	890	1 583	689	1 313	2 002
Net Earnings	1 776	653	2 429	2 040	1 000	3 040

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

The standardized measure of discounted future net cash flows relating to Suncor's proved oil and gas reserves are calculated in accordance with FASB Topic 932 — "Extractive Activities — Oil and Gas". Future cash inflows are estimated using the twelve-month average price, which are also used in estimating the entity's proved oil and gas reserves. Future development and production costs, including the associated decommissioning and restoration activities, are calculated by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. The appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, were applied to the future pretax net cash flows, less the tax basis of the properties involved. A prescribed rate of 10% is applied to discount the future net cash flows.

The calculation of the standardized measure of discounted future net cash flows is based upon information prepared by the Company's independent qualified reserves evaluators, and adjusted for decommissioning and restoration activities and future income taxes.

It should not be assumed that the estimates of future net cash flows presented in the tables below represent the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material. Future changes to income tax, royalty and environmental regulations could also have a significant impact on the respective assumptions. There is no guarantee that the estimates for SCO, bitumen, crude oil and NGLs, and natural gas reserves provided herein will be recovered. Actual SCO, bitumen, crude oil and NGLs, and natural gas reserves may be greater than or less than the estimates provided herein.

The following twelve-month average prices were used to calculate the standardized measure of discounted future net cash flows:

Year	Brent North Sea	WTI Cushing Oklahoma	WCS Hardisty Alberta	Light Sweet Edmonton Alberta	Pentanes Plus Edmonton Alberta	AECO Gas	B.C. Gas Westcoast Station 2	National Balancing Point North Sea
	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu	Cdn$/mmbtu
2014	101.70	94.99	82.80	95.98	103.40	4.40	4.09	9.52
2013	109.05	96.90	73.66	91.50	103.39	3.10	3.06	10.74

($ millions)	At December 31, 2014			At December 31, 2013		
	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Future cash inflows	309 703	25 774	335 477	297 638	24 014	321 652
Future production costs	(154 238)	(6 122)	(160 360)	(146 172)	(4 925)	(151 097)
Future development costs	(74 774)	(4 394)	(79 168)	(76 042)	(2 508)	(78 550)
Future income tax expenses	(18 212)	(8 103)	(26 315)	(16 649)	(11 486)	(28 135)
Future net cash flows	62 479	7 155	69 634	58 775	5 095	63 870
Annual 10% Discount Factor	(39 279)	(2 337)	(41 616)	(38 402)	(1 085)	(39 487)
Standardized measure of discounted future net cash flows	23 200	4 818	28 018	20 373	4 010	24 383

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

($ millions)	2014	2013
Standardized measure of discounted future net cash flows — beginning of year	24 383	25 092
Sales and transfers of oil and gas produced	(8 679)	(8 463)
Net change in sales prices and operating costs related to future production	5 310	2 193
Net change due to extensions, discoveries and improved recovery	47	(38)
Net change due to acquisitions and dispositions	(72)	(888)
Net change due to revisions in quantity estimates	52	999
Previously estimated development costs incurred during the period	5 209	4 363
Changes in estimated future development costs	(2 646)	(1 743)
Accretion of discount	2 213	2 180
Net change in income taxes	2 201	688
Standardized measure of discounted future net cash flows — end of year	28 018	24 383

QuickLinks

EXHIBIT 99-10