SUNCOR ENERGY INC
Form 40-F
March 01, 2019

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UNITED STATES
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, 2018
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.
P.O. Box 2844
Calgary, Alberta, Canada T2P 3E3
(403) 296-8000

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

CT Corporation System
28 Liberty St.
New York, New York 10005
(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, 2018 there were 1,584,484,163 Common Shares issued and outstanding**

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 for the past 90 days.

Yes ý No o

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files).

Yes ý No o

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company o

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

INCORPORATION BY REFERENCE

This annual report on Form 40-F is incorporated by reference into and as an exhibit to, as applicable, each of the following Registration Statements of the Registrant 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) and Form S-8 (File No. 333-161029). The Registrant's Annual Information Form dated February 28, 2019, 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, 2018, 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, the Registrant's Registration Statement on Form F-10 (File No. 333- 225338).

ANNUAL INFORMATION FORM DATED FEBRUARY 28, 2019

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ADVISORIES

In this Annual Information Form (AIF), references to "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint arrangements (including those identified in Note 27 of the company's 2018 audited Consolidated Financial Statements), 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 the 2018 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 thereto and the auditor's report thereon, as at and for each year in the two-year period ended December 31, 2018. References to the MD&A mean Suncor's Management's Discussion and Analysis, dated February 28, 2019.

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 and Non-GAAP Financial Measures section of this AIF for information regarding risk factors and material assumptions underlying the 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 this AIF by reference.

GLOSSARY OF TERMS AND ABBREVIATIONS

Common Industry Terms

Products

Crude oil is a mixture, consisting mainly of pentanes 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 crude oil is crude oil with a relative density greater than 31.1 degrees API gravity.

Medium crude oil is crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.

Heavy crude oil is crude oil with a relative density greater than 10.0 degrees API gravity and less than or equal to 22.3 degrees API gravity.

Synthetic crude oil (SCO) is a mixture of liquid hydrocarbons derived by upgrading bitumen and may contain sulphur or other non-hydrogen compounds. 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 a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

Conventional natural gas is natural gas that occurs in a normal, porous, permeable reservoir rock and that, at a particular time, can be technically and economically produced using normal production practices.

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

Oil and gas exploration and development terms

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

Oil sands are deposits of sand, sandstone or other sedimentary rocks that contain crude bitumen.

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

Wells

Appraisal wells are drilled into a discovered hydrocarbon accumulation to further understand the extent and size of the accumulation.

Cuttings reinjection wells are drilled for the safe disposal of drilling waste, including drill cuttings, mud slurry, old drilling fluids and waste water, in order to minimize the environmental impact.

Delineation wells are drilled to define the extent of known accumulations of petroleum for the assignment of reserves. This includes wells drilled for the purpose of assessing the stratigraphy, structure and bitumen saturation of an oil sands lease.

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 areas where excess fluids from operations can be safely injected for safe disposal. The fluid is pumped into a subsurface formation sealed off from other formations by impervious strata of rock. These wells are operated within limits approved by the appropriate regulatory bodies.

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 with the intention of discovering commercial reservoirs or deposits of crude oil and/or natural gas.

Infill wells are drilled within a known accumulation of petroleum, between existing development wells, to target regions of the reservoir containing bypassed hydrocarbons or to accelerate production.

Observation wells are used to monitor changes in a producing field. Parameters being monitored may include fluid saturations, temperature or 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 purpose of injecting gas, steam or water, or observation wells.

Stratigraphic test 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 terms

Crude 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 products for the company's downstream operations.

Diluent is a light hydrocarbon mixture used to blend with bitumen or heavy crude oil to reduce its viscosity so that it can be transported by pipeline.

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

Extraction refers to the process of separating bitumen from oil sands.

Froth treatment refers to the process of adding a light hydrocarbon to bitumen froth produced in the extraction process in order to separate the bitumen from the water and fine solids in the bitumen froth.

In situ refers to methods of extracting bitumen from oil sands other than by 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.

Paraffinic froth treatment (PFT) refers to a froth treatment process whereby a lighter diluent or solvent that contains more paraffin is used, resulting in a higher quality bitumen that can be sold directly to market without further upgrading.

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-assisted gravity drainage (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 heat the bitumen. 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.

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.

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 crude oil, bitumen or natural gas.

Reserves

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

Common Abbreviations

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

Measurement

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 of natural gas equivalent
GJ	gigajoules
mmbtu	millions of British thermal units
API	American Petroleum Institute
CO_2	carbon dioxide
CO_{2e}	carbon dioxide equivalent
m^3	cubic metres
m^3/d	cubic metres per day
m^3/s	cubic metres per second
km	kilometres
MW	Megawatts
Mt	Megatonnes

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

Suncor converts certain natural gas volumes to boe, boe/d, mboe, mboe/d and 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, conversion on a 6:1 basis may be misleading as an indication of value.

Conversion Table(1)(2)

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

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

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

CORPORATE STRUCTURE

Name, Address 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. The company amended its articles in 1995 to move its 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 under the CBCA, which was completed effective August 1, 2009, Suncor amalgamated with Petro-Canada to form a single corporation continuing under the name "Suncor Energy Inc." On January 1, 2017, Suncor amalgamated with certain of its wholly owned subsidiaries under the CBCA.

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

Intercorporate Relationships

Material subsidiaries, each of which was owned 100%, directly or indirectly, by the company as at December 31, 2018, are as follows:

Name	Jurisdiction Where Organized	Description
Canadian operations		
Suncor Energy Oil Sands Limited Partnership	Alberta	This partnership holds most of the company's Oil Sands operations assets.
Suncor Energy Products Partnership	Alberta	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Marketing Inc.	Alberta	Through this subsidiary, production from Suncor's upstream Canadian businesses is marketed. This subsidiary also administers Suncor's energy trading and power activities, markets certain third-party products, procures crude oil feedstock and natural gas for Suncor's downstream business, and procures and markets NGLs and LPG for Suncor's downstream business.
Suncor Energy Ventures Corporation	Alberta	A subsidiary which indirectly owns a 36.74% ownership in the Syncrude joint operation.
Suncor Energy Ventures Partnership	Alberta	This partnership owns a 22% ownership in the Syncrude joint operation.
U.S. operations		
Suncor Energy (U.S.A.) Marketing Inc.	Delaware	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.	Delaware	A subsidiary through which Suncor's U.S. refining and marketing operations are conducted.

International operations

Suncor Energy UK Limited	U.K.	A subsidiary through which the majority of Suncor's operations in the U.K. are conducted.

The company's remaining subsidiaries each accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2018, and (ii) less than 10% of the company's consolidated operating revenues for the fiscal year ended December 31, 2018. In aggregate, the remaining subsidiaries accounted for less than 20% of the company's consolidated assets as at December 31, 2018, and less than 20% of the company's consolidated operating revenues for the fiscal year ended December 31, 2018.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Suncor is an integrated energy company headquartered in Calgary, Alberta, Canada. The company is strategically focused on developing one of the world's largest petroleum resource basins Canada's Athabasca oil sands. In addition, Suncor explores for, acquires, develops, produces and markets crude oil and natural gas in Canada and internationally; the company transports and refines crude oil, and markets petroleum and petrochemical products primarily in Canada. The company also conducts energy trading activities focused principally on the marketing and trading of crude oil, natural gas, power and byproducts. Suncor also operates a renewable energy business as part of its overall portfolio of assets.

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 is comprised of:

Oil Sands operations refer to Suncor's 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, cogeneration units, energy and reclamation facilities.

In Situ operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities, cogeneration units, hot bitumen infrastructure including insulated pipelines, diluent import lines and a cooling and blending facility and associated storage assets such as Suncor's East Tank Farm (ETF) operations specific to In Situ. Production is either upgraded by Oil Sands Base, or blended with diluent and marketed directly to customers.

Fort Hills refers to Suncor's 54.11% interest in the Fort Hills mining project, where Suncor is the operator. During the first quarter of 2018, the company acquired an additional 1.05% interest in Fort Hills for consideration of $145 million, increasing its interest from its previous 53.06% as an outcome of the commercial settlement agreement reached among the Fort Hills partners in December 2017. The Fort Hills project includes the mine, primary and secondary extraction facilities, and supporting infrastructure. The ETF facility was expanded in July 2017 to support Fort Hills production. The expanded facilities that blend Fort Hills bitumen for Suncor and the other Fort Hills partners are described as the East Tank Farm Development (ETFD). On November 22, 2017, the company completed the disposition of a combined 49% ownership interest in the new ETFD to the Fort McKay First Nation and the Mikisew Cree First Nation through the creation of the Thebacha Limited Partnership.

Syncrude refers to Suncor's 58.74% working interest in the Syncrude joint operation in the Athabasca oil sands region. Syncrude consists of the Aurora and Mildred Lake mining and extraction operations, integrated upgrading facilities and the associated infrastructure for these assets including utilities, energy and reclamation facilities. On February 23, 2018, Suncor acquired an additional 5% interest in Syncrude from Mocal Energy Limited (Mocal) for $923 million, increasing its interest from its previous 53.74%.

EXPLORATION AND PRODUCTION

Suncor's Exploration and Production (E&P) segment consists of offshore operations in Canada, the U.K. and Norway, and onshore assets in Libya and Syria.

E&P Canada operations include Suncor's 37.675% working interest in Terra Nova, which Suncor operates. Suncor also holds non-operated interests in Hibernia (20% in the base project and 19.190% in the Hibernia Southern Extension Unit (HSEU)), White Rose (27.5% in the base project and 26.125% in the extensions), and Hebron (21.034%). In addition, Suncor holds interests in several exploration licences and significant discovery licences offshore of Newfoundland and Labrador. E&P Canada previously included Suncor's northeast B.C. mineral landholdings; however, on March 23, 2018, the company completed the exchange of its northeast B.C. mineral landholdings, including associated production, along with additional cash consideration of $52 million with Canbriam Energy Inc. (Canbriam) for a 37% equity interest in the private natural gas company.

E&P International operations include Suncor's non-operated interests in Buzzard (29.89%), Golden Eagle Area Development (GEAD) (26.69%), the Rosebank future development project (40%), in which the company acquired an additional 10% interest during 2018 bringing Suncor's interest in the project to 40% from its previous 30%, the Oda project (30%) and the Fenja development project (17.5%), which Suncor acquired on May 31, 2018 from Faroe Petroleum Norge AS (Faroe). The first three projects are located offshore of the U.K., while the Oda and Fenja projects are located offshore of Norway. Suncor also holds interests in several exploration licences offshore of 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; some of these oilfields remain shut in due to political unrest, with the timing of a return to normal operations uncertain. Suncor also owns, pursuant to a PSC, an interest in the Ebla gas development in Syria. Suncor's operations in Syria were suspended indefinitely in 2011 due to political unrest in the country, and the company believes the assets in both Libya and Syria have sustained various degrees of damage over the past several years, including certain assets that the company believes have sustained significant damage.

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 include refineries located in Montreal, Quebec and Sarnia, Ontario.

Western North America operations include refineries located in Edmonton, Alberta and Commerce City, Colorado.

Other Refining and Supply assets include interests in a petrochemical plant and a sulphur recovery facility in Montreal, Quebec, product pipelines and terminals in Canada and the U.S., and the St. Clair ethanol plant in Ontario.

Marketing operations sell refined petroleum products to retail, commercial and industrial customers through a combination of Petro-Canada® and Sunoco® company-owned locations and branded-dealers, a nationwide commercial road transport network and a bulk sales channel in Canada, as well as through other retail stations and wholesale customers in Colorado and Wyoming.

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 investment activities include development, construction, and ownership of Suncor-operated and joint venture partner-operated renewable power facilities across Canada. This includes a portfolio of operating wind power facilities located in Alberta, Saskatchewan and Ontario, as well as a portfolio of optioned lands for future wind and solar power project development.

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 **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.

2016

Acquisition of Canadian Oil Sands Limited (COS). In the first quarter of 2016, Suncor acquired COS, which owned 36.74% of Syncrude. This acquisition has provided Suncor with an incremental 128,600 bbls/d of SCO production capacity through its additional ownership interest in Syncrude.

Acquisition of additional 5% interest in Syncrude. In June 2016, Suncor acquired an additional 5% interest in Syncrude from Murphy Oil Company Limited (Murphy), which added a further 17,500 bbls/d of SCO capacity, bringing Suncor's ownership interest in Syncrude at that time to 53.74%.

Completed a turnaround of the Upgrader 2 facilities. The first full turnaround of the Upgrader 2 facilities was completed since the company moved to a five-year cycle.

Executed an equity offering for net proceeds of $2.8 billion. The net proceeds were used to fund the acquisition of the additional 5% interest in Syncrude from Murphy and to reduce debt to provide ongoing balance sheet flexibility.

Oil Sands operations production returned safely to normal operating rates. Suncor's Oil Sands production, including Syncrude, was completely shut in during the forest fires in the Fort McMurray region. Suncor leveraged its capability to safely evacuate community members and workers from the region. No assets were damaged during the forest fires and operations subsequently returned to normal production rates by mid-July.

Purchased 30% participating interest in the Rosebank project. The Rosebank project is considered one of the largest remaining undeveloped resources in the U.K. North Sea. The project is expected to be complementary to Suncor's existing U.K. portfolio.

2017

Sale of Suncor's interest in the Cedar Point wind facility. On January 24, 2017, the company closed the sale of its 50% share of Cedar Point for gross proceeds of $291 million.

Sale of Petro-Canada Lubricants Inc. (PCLI) business. On February 1, 2017, the company completed the sale of PCLI, including the production and manufacturing facilities in Mississauga, Ontario as well as the global marketing and distribution assets held by PCLI, for gross proceeds of $1.125 billion to a subsidiary of HollyFrontier Corporation (HollyFrontier). The sale of PCLI reinforced the company's commitment to continuously optimize its asset portfolio and focus on core assets.

Suncor commenced a normal course issuer bid (NCIB). Suncor filed its notice of intention to commence a new NCIB to purchase and cancel up to $2.0 billion of the company's common shares, beginning on May 2, 2017 and ending on May 1, 2018, through the facilities of the TSX, NYSE and/or alternative trading platforms. As at December 31, 2017, the company had repurchased 33.2 million common shares at an average price of $42.61 per share, for a total repurchase cost of $1.413 billion.

West White Rose Project sanctioned. Suncor is a non-operating partner with a blended working interest of approximately 26%. The company's share of peak oil production is estimated to be 20,000 bbls/d.

Sale of Suncor's interest in the Ripley wind facility. On July 10, 2017, the company closed the sale of its 50% share of Ripley for gross proceeds of $48 million.

Sale of 49% equity interest in Suncor's ETFD. On November 22, 2017, the company closed the sale to Fort McKay First Nation and Mikisew Cree First Nation of a 49% equity interest in Suncor's ETFD for gross proceeds of $503 million. The deal represents the largest business investment to date by First Nations in Canada.

US$750 million notes offering. On November 15, 2017, the company issued US$750 million of 4.00% senior unsecured notes due in 2047.

First oil from Hebron. Hebron commenced production of oil on November 27, 2017.

Repayment of debt. The company repaid US$1.25 billion 6.10% notes, US$600 million 6.05% notes and $700 million 5.80% notes all originally scheduled to mature in the first half of 2018. The reduction in outstanding debt reduced financing costs and has provided ongoing balance sheet flexibility.

Fort Hills commercial dispute resolution. On December 21, 2017, the Fort Hills partners resolved their commercial dispute with respect to funding of project capital and reached an agreement pursuant to which Suncor acquired an additional 2.26% interest in the project for consideration of $308 million, bringing Suncor's ownership interest in the project at that time to 53.06%.

2018

First oil from Fort Hills. On January 27, 2018, the Fort Hills project began producing paraffinic froth-treated bitumen from secondary extraction and production successfully ramped up and averaged 94% of the project's nameplate capacity of 194 mbbls/d (105 mbbls/d, net to Suncor) in the fourth quarter of 2018, exceeding the company's target of 90%.

Renewal of NCIB and increase in share repurchases. In May 2018, Suncor renewed its NCIB to continue to repurchase its common shares through the facilities of the TSX, NYSE and/or alternative trading platforms between May 4, 2018 and May 3, 2019. On November 14, 2018, the TSX accepted a notice filed by the company of its intention to amend the NCIB effective November 19, 2018 to increase the maximum number of common shares that may be repurchased from 52,285,330 to 81,695,830 common shares. In 2018, the company repurchased 64.4 million common shares for cancellation at an average price of $47.38 per share, for a total repurchase cost of $3.053 billion. Subsequent to December 31, 2018, Suncor's Board of Directors approved a further share repurchase program of up to $2.0 billion.

Acquisition of additional 5% interest in Syncrude. On February 23, 2018, Suncor acquired an additional 5% interest in Syncrude from Mocal for $923 million, adding a further 17,500 bbls/d of SCO capacity and increasing the company's ownership interest to 58.74%.

Asset exchange with Canbriam. On March 23, 2018, Suncor completed the exchange of its northeast B.C. mineral landholdings, including associated production, along with additional cash consideration of $52 million for a 37% equity interest in Canbriam, a private natural gas company.

Purchased 17.5% participating interest in the Fenja development project. On May 31, 2018, the company acquired a 17.5% non-operated interest in the Fenja development project located offshore Norway from Faroe for acquisition costs of $70 million, plus interim settlements costs of $22 million. This project was sanctioned by its owners in December 2017, with first oil anticipated in 2021, with peak production expected to reach 34 mbbls/d (6 mbbls/d net to Suncor) between 2021 and 2022.

Acquisition of additional 1.05% interest in Fort Hills. During the first quarter of 2018, Suncor acquired an additional 1.05% interest in the Fort Hills project for consideration of $145 million, bringing Suncor's ownership interest in the project to 54.11%. The additional interest is an outcome of the commercial settlement agreement reached among the Fort Hills partners in December 2017.

Disposition of Joslyn Oil Sands Mining Project (Joslyn). On September 29, 2018, Suncor along with the other working interest partners in Joslyn, agreed to sell 100% of their respective working interests to Canadian Natural Resources Limited (CNRL) for gross proceeds of $225 million, $82.7 million net to Suncor. Suncor held a 36.75% working interest in Joslyn prior to the transaction.

Production ramp up at Hebron. Drilling activity at Hebron was ongoing throughout 2018, with the third and fourth production wells coming online in April and October 2018, respectively. Production continues to ramp up ahead of expectations, averaging 13.0 mbbls/d in 2018. At peak, Hebron is expected to produce 31.6 mbbls/d, net to Suncor.

Buzzard Phase 2 sanctioned. During 2018, Buzzard Phase 2 was sanctioned by Suncor and the other project partners and the plan for development was approved by the U.K. Oil and Gas Authority. Suncor holds a 29.89% non-operated interest in the project. First oil is anticipated in early 2021.

Repayment of debt. The company completed an early retirement of US$83 million of subsidiary debt acquired through the acquisition of COS with a coupon of 7.75%, originally scheduled to mature on May 15, 2019.

Syncrude bi-directional pipeline. During the fourth quarter of 2018, Suncor and its joint venture partners reached an agreement to build bi-directional interconnecting pipelines, which will connect Syncrude's Mildred Lake site and Suncor's Oil Sands Base plant. The pipelines will provide increased operational flexibility through the ability to transfer bitumen and gas oils between the two plants, enabling higher reliability and utilization. The pipelines are expected to be operational by the end of 2020, subject to finalized commercial terms and regulatory approval.

Full implementation of autonomous haulage systems (AHS) at North Steepbank. During 2018, the company completed the implementation of AHS at its North Steepbank mine. Autonomous haul trucks, which operate using GPS, wireless communication and perceptive technologies, offer a number of advantages over existing truck and shovel operations, including enhanced safety performance, better operating efficiency and lower operating costs. Implementation is planned at Millennium and Fort Hills over the next six years.

Government of Alberta Mandatory Production Curtailment. In December 2018, the Government of Alberta announced an overall production curtailment program which began on January 1, 2019. Suncor's estimate of the impact of the curtailment program on its business has been included in the company's production guidance for 2019 issued on December 14, 2018.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

For a discussion of the environmental and other regulatory conditions, and competitive conditions and seasonal impacts affecting Suncor's 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

Suncor's integrated Oil Sands Base operations, located in the Athabasca oil sands region 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 the extraction processes. Bitumen is upgraded through a coking and distillation process. The upgraded product, referred to as sour SCO, is either sold to market 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 ultra-low sulphur diesel fuel 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, most 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

Suncor regularly conducts planned maintenance events at its facilities. Large planned maintenance events that require units to be taken offline to be completed are often referred to as turnarounds. Turnaround maintenance provides opportunities for both preventive maintenance and capital replacement, which are expected to improve reliability and operational efficiency. Planned maintenance events generally occur on routine cycles, determined by historical operating performance, recommended usage factors or regulatory requirements. A turnaround typically involves shutting down the unit, inspecting it for wear or other damage, repairing or replacing components, and then restarting the unit. Production levels and product mix are typically impacted during these activities.

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.

Oil sands tailings are the remaining sand, water, clay, silt and residual hydrocarbons left after the majority of hydrocarbons are extracted from the ore during the water-based bitumen extraction process. Suncor's updated and approved tailings management plan involves an increase in treatment capacity using Accelerated De-Watering and treatment of mature fine tailings at Oil Sands Base, including the construction of a Permanent Aquatic Storage Structure (PASS). This approach is supported by the construction, operation and ongoing monitoring of a Demonstration Pit Lake, and aligns with the Government of Alberta's Tailings Management

Framework (TMF) and the Alberta Energy Regulator's (AER) Directive 085 Fluid Tailings Management for Oil Sands Mining Projects (the Tailings Directive).

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 2018, the company mined approximately 138 million tonnes of bitumen ore (2017 169 million tonnes) and processed an average of 259 mbbls/d of mined bitumen in its extraction facilities (2017 306 mbbls/d).

Upgrading Facilities

Suncor's upgrading facilities consist of two upgraders: Upgrader 1, which has capacity of approximately 110 mbbls/d of SCO, and Upgrader 2, which has 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 2018, Suncor averaged 280 mbbls/d of upgraded (SCO and diesel) production net of the company's internal consumption (2017 318 mbbls/d), mainly sourced from bitumen provided by both Oil Sands Base and In Situ operations, as well as from bitumen froth production that was processed from Fort Hills in connection with testing the front end of the plant. The decrease in 2018 utilization compared to 2017 was primarily due to both planned and unplanned maintenance at Upgrader 2.

Other Mining Leases

Suncor, directly and indirectly, owns interests in several other mineable oil sands leases, including Voyageur South and Audet. 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 at Firebag and MacKay River use SAGD technology to produce bitumen from oil sands deposits that are too deep to be mined.

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 through 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 fuelled 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 and sold to the Alberta 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 characteristics 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 well pairs from existing well pads or constructs new well pads to facilitate future well pair drilling and production.

In Situ Assets

Firebag

Production from Suncor's Firebag operations commenced in 2004. The Firebag complex has central processing facilities with a total capacity of 203 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, 2018, Firebag had 15 well pads in operation, with 207 SAGD well pairs and 52 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 474 MW of electricity. The Firebag site power load requirements are approximately 116 MW and, in 2018, Firebag exported approximately 287 MW of electricity to the Alberta power grid and Oil Sands Base plant. There are also 13 OTSGs at the site for additional steam generation.

During 2018, Firebag production averaged 204 mbbls/d (2017 182 mbbls/d) with a SOR of 2.7 (2017 2.7).

MacKay River

Production from Suncor's MacKay River operations commenced in 2002. As at December 31, 2018, MacKay River included seven well pads with 110 well pairs either producing or on initial steam injection. The MacKay River central processing facilities have debottlenecked bitumen processing capacity of 38 mbbls/d. TransCanada Energy Ltd. owns the on-site cogeneration unit, which Suncor operates under a commercial agreement, that generates steam and electricity. There are also four OTSGs at the site for additional steam generation.

During 2018, MacKay River production averaged 36 mbbls/d (2017 31 mbbls/d) with a SOR of 2.9 (2017 3.1).

Other In Situ Leases

Suncor owns and operates several other oil sands leases which may support future in situ production, including Lewis, Meadow Creek, OSLO and Chard. Suncor holds a 100% working interest in Lewis, a 75% working interest in Meadow Creek, a 77.78% working interest in OSLO, and interests varying from 25% to 50% in Chard. In 2018, Suncor acquired a 100% working interest in leases within the Gregoire area adjacent to its Meadow Creek lands. Meadow Creek is a SAGD project that is part of Suncor's planned in situ replication strategy. Suncor holds a 75% interest and is operator of the project, located approximately 40 km south of Fort McMurray. Meadow Creek consists of two independent In Situ projects: Meadow Creek East and Meadow Creek West.

In early 2017, Suncor received AER approval for the Meadow Creek East project. This approval is Suncor's first in situ development approval since Firebag. The project is expected to be developed in two stages with anticipated gross production of 40 mbbls/d up to 80 mbbls/d. Construction could begin as early as 2020, with first oil from the first phase expected as early as 2023.

In October 2017, Suncor submitted an application for the Meadow Creek West project to the AER. Meadow Creek West is expected to be developed in a single stage and has an anticipated gross production capacity of 40 mbbls/d. Construction is anticipated to begin in 2023, with first oil expected as early as 2025.

In February 2018, Suncor submitted an application for the Lewis project to the AER. Lewis is a SAGD project and is also part of Suncor's planned in situ replication strategy. Suncor holds a 100% interest in the project, located approximately 25 km northeast of Fort McMurray. The project is expected to be developed in stages, with anticipated peak production of 160 mbbls/d. Construction could begin as early as 2024, with first oil expected as early as 2027.

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. Fort Hills operations are substantially similar to those of Suncor's Oil Sands Base assets; however, Fort Hills uses a PFT process to produce a marketable bitumen product that is partially decarbonized, resulting in a higher quality bitumen requiring less diluent and eliminating the need for on-site upgrading facilities.

Suncor holds a 54.11% working interest in Fort Hills and is the operator of the project. The company's interest in Fort Hills increased from its previous 53.06% to 54.11% in the first quarter of 2018, pursuant to the agreement reached among the partners in December 2017 in connection with the resolution of their commercial dispute. Fort Hills began producing PFT bitumen from secondary extraction on January 27, 2018. The second and third trains of secondary extraction were subsequently completed in the first half of 2018 as per the original plan. Fort Hills achieved average utilization of 94% in the fourth quarter of 2018. Fort Hills has a nameplate capacity of 194 mbbls/d (gross) of bitumen (105 mbbls/d net to Suncor). During 2018, Suncor's share of Fort Hills production averaged 67.4 mbbls/d (2017 nil) from approximately 38.9 million tonnes of bitumen ore mined (2017 nil).

Syncrude

Suncor holds a 58.74% interest in the Syncrude joint operation, which has gross bitumen conversion to SCO capacity of 350 mbbls/d (206 mbbls/d net to Suncor). Suncor's interest in Syncrude increased during 2018 from its previous 53.74% to 58.74% as a result of the acquisition of Mocal's 5% interest. Syncrude began producing in 1978 and is operated by Syncrude Canada Ltd. (SCL). In 2006, SCL entered into a management services agreement with Imperial Oil Resources Limited (Imperial Oil) to provide business services. The project is located near Fort McMurray and includes mining operations at Mildred Lake and Aurora North. In 2012, the Syncrude joint venture partners announced a plan to develop two mining areas adjacent to the current mine, Mildred Lake West Extension (MLX-W) and Mildred Lake East Extension (MLX-E), subject to final sanctioning and regulatory approvals, which would consequently extend the life of Mildred Lake by a minimum of 10 years. In 2015, a decision was made by the joint venture partners to progress with the MLX-W program. The MLX-E program is expected to follow MLX-W development if economic conditions prove suitable. The MLX-W program is expected to sustain bitumen production levels at the Mildred Lake site after resource depletion at the North Mine. The plan proposes to use existing mining and extraction facilities. Regulatory applications for these areas were submitted in 2014. A hearing with the AER and stakeholder groups began in early 2019. A decision by the AER is expected by mid-2019, with regulatory approvals expected to follow. Provided that economic conditions support such a project, sanctioning of MLX-W is expected in late 2019 or early 2020.

Suncor has been collaborating with Syncrude for several years to achieve sustained reliability improvements and reduce costs. In January 2019, Suncor and SCL entered into a master business services agreement designed to enable Suncor to provide certain business services to SCL. The proximity of Syncrude to Oil Sands Base affords an opportunity for cost management and collaboration between the company and Syncrude in order to provide opportunities to optimize assets, including during periods of planned maintenance or interruption. During the fourth quarter of 2018, Suncor and its joint venture partners reached an agreement to build bi-directional interconnecting

pipelines, which will connect Syncrude's Mildred Lake site and Suncor's Oil Sands Base plant. The pipelines will provide increased operational flexibility through the ability to transfer bitumen and gas oils between the two plants, enabling higher reliability and utilization. The pipelines are expected to be operational by the end of 2020, subject to finalized commercial terms and regulatory approval.

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 rich fuel gas from upgrading operations. At Aurora North, Syncrude operates two cogeneration units which provide heat and power.

Syncrude produces a single sweet SCO product. Marketing of this product is the responsibility of the individual joint venture partners.

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 centrifuge technology that separates water from tailings. The updated tailings management plan for Syncrude Aurora North was approved by the AER in June 2018. The updated tailings management plan for Syncrude Mildred Lake is pending approval by the AER.

In 2018, Suncor's share of Syncrude production averaged 144.2 mbbls/d (2017 134.3 mbbls/d). Sustaining capital expenditures in 2019 for Syncrude are expected to focus on a planned turnaround and reliability improvements. Production in the third quarter of 2018 was significantly impacted by a site wide power outage that occurred late in the second quarter of 2018 and the staged return to service of the asset. Production at Syncrude returned to normal operating rates within the third quarter of 2018 following the required transformer repairs, accelerated planned maintenance and the planned upgrader turnaround.

Other Oil Sands Leases

Suncor indirectly owns interests in other mineable oil sands leases, including Mildred Lake West, Mildred Lake East, Lease 29, Lease 30 and Aurora South, through the company's 58.74% working interest in the Syncrude joint operation. On September 29, 2018, Suncor and the other working interest partners in Joslyn agreed to sell 100% of their respective working interests in the project to CNRL for gross proceeds of $225 million, $82.7 million net to Suncor. Suncor held a 36.75% working interest in Joslyn prior to the transaction.

New Technology

Technology is a fundamental component of Suncor's business. Suncor 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 commercial viability. The necessary validation typically occurs through a series of progressive steps which allow results to be reliably scaled and assessed for implementation.

Following a successful commercial-scale evaluation, the company began proceeding with the phased implementation of AHS at its operated mine sites. Full implementation was completed in 2018 at the North Steepbank mine, with implementation planned at Millennium and Fort Hills over the next six years. Autonomous haul trucks, which operate using GPS, wireless communication and perceptive technologies, have demonstrated an ability to maneuver safely, effectively and efficiently in Suncor's operating environment and offer a number of advantages over existing truck and shovel operations, including enhanced safety performance, better operating efficiency and lower operating costs. During 2018, the company moved a total of 387 million tonnes of ore and overburden with AHS.

In 2018, Suncor completed the implementation of PASS technology as part of the company's accelerated dewatering project. PASS enables the dewatering of fine tailings from existing tailings ponds and the eventual reclamation and closure of tailings ponds. PASS technology consists of a proprietary mixture of coagulants and flocculants that enable water release and sequestration of fine tailings. The first pond, Pond 8B, commenced drainage using PASS technology in 2018.

Suncor is also working on, or has completed, several new technology projects that are proceeding with the next phase of field testing. Examples of Suncor's new technology projects include:

Electromagnetically Assisted Solvent Extraction (EASE) This new method of in situ bitumen recovery uses radio frequency heating, in conjunction with a light hydrocarbon, with the goal of reducing energy, greenhouse gas (GHG) and water footprints. Testing of this technology will use Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH). The second phase of the pilot project began operations in the third quarter of 2015 and is expected to continue through 2019.

In Situ Demonstration Facility (ISDF) The ISDF is expected to allow Suncor to test a suite of enhanced in situ technologies. This demonstration facility is intended to enable Suncor to accelerate the testing of in situ technologies that use a combination of injected light hydrocarbons and well bore heating, including Solvent+, with the goal of improving conventional in situ extraction methods and has the potential to improve environmental and economic performance. The ISDF will be located at MacKay River and received AER approval in late 2018.

Steam-Assisted Gravity Drainage Less Intensive Technology Enhanced (SAGD LITE) Field trials are underway to evaluate new SAGD technologies such as non-condensable gas addition, where light hydrocarbons such as methane or other NGLs are added; solvent addition through a technology known as Expanding Solvent SAGD (ES-SAGD); flow control devices; and injection control devices. These technologies are expected to improve cost, SORs, ultimate recovery and productivity, while reducing water use and GHG emissions. Monitoring and evaluation will continue throughout 2019, including a commercial scale ES-SAGD pilot at Firebag.

Zero-Impact Seismic Zero-Impact Seismic is a seismic technology that has the potential to reduce the surface disturbance of SAGD by up to 50% as it does not require cutlines. This has the potential to reduce impacts to wildlife habitats and reduce stress on caribou populations. The company is planning a commercial scale pilot for the 2019 to 2020 time frame.

Non-Aqueous Extraction (NAE) NAE is a potential new extraction process for oil sands mining operations that utilizes solvents as opposed to water as the primary extraction means, which has the potential to eliminate tailings ponds while reducing costs and GHG emissions. The company is planning a commercial scale pilot for the 2021 to 2022 time frame.

Sales of Principal Products

Primary markets for SCO and bitumen production from Suncor's Oil Sands segment, including PFT bitumen from Fort Hills, include refining operations in Alberta, Ontario, Quebec, the U.S. Midwest and the U.S. Rocky Mountain regions, and markets on the U.S. Gulf Coast. Diesel production from upgrading operations is sold primarily in Western Canada and the United States.

For bitumen production from In Situ operations, Suncor's marketing strategy allows it to take advantage of changes in market conditions by either upgrading the bitumen at the company's Oil Sands Base facilities, refining diluted bitumen at Suncor's Edmonton refinery, or selling diluted bitumen to third parties. Increased bitumen sales may also be required during upgrading facility outages. In Situ bitumen production processed by Oil Sands Base upgrading facilities in 2018 increased to 106 mbbls/d or 44% (2017 101 mbbls/d or 47%) of total in situ bitumen production.

	2018		2017	
Sales Volumes and Operating Revenues Principal Products	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
SCO and diesel (including Syncrude)	**431.7**	**83**	453.4	87
Bitumen	**191.3**	**15**	110.6	12
Byproducts and other operating revenues[(1)]	**n/a**	**2**	n/a	1
	623.0		564.0	

(1) Operating revenues include revenues associated with excess power from cogeneration units.

In the normal course of business, Suncor processes its proprietary sour SCO at the company's refineries or enters into long-term 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, including Fort Hills, is gathered into Suncor's Fort McMurray facilities at the Athabasca Terminal, which is operated by Enbridge Inc. (Enbridge), or the ETF, which is operated by Suncor, and connected to the Athabasca Terminal. 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 and operated by Suncor. At Edmonton, the product is processed in Suncor's Edmonton refinery, sold to other local refiners, or transferred onto the Enbridge mainline or the TransMountain Pipeline system.

- To Cheecham, Alberta on the Enbridge Athabasca Pipeline or the Enbridge Wood Buffalo Pipeline. From Cheecham on the Enbridge Athabasca Pipeline or the Enbridge Wood Buffalo Pipeline Extension to Hardisty, Alberta.

- To Edmonton via the Enbridge Waupisoo Pipeline, originating at Cheecham.

From Edmonton and Hardisty, where Suncor has both owned storage capacity and 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.
- To Suncor's Sarnia refinery on the Enbridge mainline and to Suncor's Montreal refinery from Sarnia on Enbridge's Line 9.
- To most major refining hubs via the Enbridge mainline, Express/Platte and Keystone pipeline systems.
- To U.S. Puget Sound refineries and to global markets via the TransMountain pipeline, as well as by rail.

Production from Syncrude is moved to market via the Athabasca Oil Sands Pipeline, which is operated by Pembina.

Royalties

Oil Sands Royalties

Oil sands projects are subject to the royalty framework issued by the Government of Alberta (the Royalty Framework), and regulated by the *Oil Sands Royalty Regulation 2009* (OSRR 2009) and supporting regulations, which were sanctioned in 2008. Under the Royalty Framework, royalties for oil sands projects are based on a sliding-scale rate of 25% to 40% of net revenue (net revenue royalty or NRR), subject to a minimum royalty within a range of 1% to 9% of gross revenue (gross revenue royalty or GRR). 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 for the minimum rate to the maximum rate at a WTI price of Cdn$120/bbl. A royalty project remains subject to the minimum royalty (the pre-payout phase) until the project's cumulative gross revenue exceeds its cumulative costs, including an annual investment allowance (the post-payout phase). During the post-payout phase, the annual royalty paid to the province is the greater of the GRR and NRR.

In 2018, Suncor incurred royalties at an average rate of 1% of gross revenue for Oil Sands Base (2017 1%) and at an average rate of 3% of gross revenue for Syncrude operations (2017 6%). Oil Sands Base and the Syncrude project are both in the post-payout phase.

Fort Hills is subject to the same Royalty Framework as Oil Sands Base and Syncrude; however, Fort Hills is in the pre-payout phase. In 2018, Fort Hills incurred royalties at an average rate of 2% of gross revenue.

In 2018, Suncor incurred royalties for MacKay River, which is in the post-payout phase, at an average rate of 14% of gross revenue at the NRR (2017 2%), and royalties at an average rate of 5% of gross revenue for Firebag (2017 2%), 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 four 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 Floating Production, Storage and Offloading (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. Drilling activities took place at Terra Nova throughout 2018 and drilling will continue in 2019. As at December 31, 2018, there were 28 wells: 17 oil production wells, nine water injection wells and two gas injection wells.

In 2018, Suncor's share of Terra Nova production averaged 11.7 mbbls/d (2017   11.5 mbbls/d). Annual turnaround maintenance was completed at the Terra Nova facility in August 2018, which lasted approximately 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., the production system is a fixed Gravity Based Structure (GBS) that sits on the ocean floor, and has gross production capacity of 230 mbbls/day (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, 2018, there were 72 wells: 40 oil production wells, 26 water injection wells, five gas injection wells, and one water-alternating-gas injection well.

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. At the end of 2018, there were seven oil production wells and nine water injection wells in the HSEU. The production wells were drilled from the GBS platform and are included in the Hibernia well count above. All nine of the water injection wells were drilled using a mobile offshore drill rig. Water for injection purposes is supplied from the GBS platform via a subsea flowline.

In 2018, Suncor's share of Hibernia production averaged 22.1 mbbls/d (2017 28.5 mbbls/d). Production in 2018 was impacted by turnaround maintenance which lasted approximately five weeks and was completed in October.

White Rose and the White Rose Extensions

White Rose is approximately 350 km southeast of St. John's. Operated by Husky Oil Operations Limited (Husky), 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, 2018, there were 44 wells: 24 oil production wells, 16 water injection wells, three gas storage wells, and one gas injection well.

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. First oil was achieved at North Amethyst in May 2010. Development of the South White Rose Extension began in 2013, with first oil being achieved in June 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 September 2011. The second stage, West White Rose Project (WWRP), was sanctioned during the second quarter of 2017 with first oil originally targeted for 2022; however, due to the delay in the tow-out schedule by one year, achieving this first oil date is uncertain. An update from the project operator is expected in the first half of 2019. The project is expected to extend the life of the existing White Rose assets, with Suncor's share of peak oil production estimated to be 20 mbbls/d. Major development activity began in 2018 and will continue in 2019.

In 2018, Suncor's share of White Rose production averaged 6.6 mbbls/d (2017 11.4 mbbls/d). Turnaround maintenance was completed at White Rose in June 2018, which lasted approximately three weeks. Production at the White Rose field was shut in from mid-November 2018 to late January 2019 due to operational complications. Return to normal production rates is expected to occur in a phased approach which began in January 2019.

Hebron

The Hebron oilfield is located 340 km southeast of St. John's and is operated by ExxonMobil Canada Properties (ExxonMobil Canada). The development includes a concrete GBS that sits on the ocean floor and supports an integrated topsides deck used for production, drilling and accommodations. At peak, the Hebron project is expected to produce 31.6 mbbls/d, net to Suncor, ramping up over the next several years. Hebron has a gross oil storage capacity of 1,200 mbbls and 52 well slots. First oil was achieved in November 2017.

During 2018, drilling activities continued at Hebron and will continue throughout 2019. In 2018, Suncor's share of production averaged 13.0 mbbls/d (2017 0.4 mbbls/d). As at December 31, 2018, there were seven wells: four oil production wells, one water injection well, one gas injection well, and one cuttings reinjection well.

Other Assets

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. During 2018, Suncor was the successful bidder on two exploration licences, including operatorship of one of the two licences, west of the Terra Nova field. In addition, Suncor became an interest holder, with Equinor Canada Ltd., in a licence east of the White Rose field. These licences carry work commitments from 2019 to 2024. The company also holds interests in 48 significant discovery licences and three exploration licences offshore in this area.

North America Onshore

During 2018, Suncor completed an exchange of its northeast B.C. mineral landholdings, including associated production, along with additional cash consideration of $52 million to Canbriam for a 37% equity interest in the private natural gas company.

E&P International Assets and Operations

Offshore U.K. & Norway

Buzzard

The Buzzard oilfield is located in the Outer Moray Firth, 95 km northeast of Aberdeen, Scotland. Operated by CNOOC Petroleum Europe Limited (CNOOC Europe), 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 and consists of four bridge-linked platforms supporting wellhead facilities, production facilities, living quarters and utilities, as well as sulphur handling. Drilling activities took place at Buzzard during 2018. As at December 31, 2018, there were 47 wells: 33 oil and gas production wells and 14 water injection wells. In 2018, Suncor's share of Buzzard production averaged 34.2 mboe/d (2017 43.8 mboe/d). In 2018, Buzzard Phase 2 was sanctioned by Suncor and the other project partners and the plan for development was approved by the U.K. Oil and Gas Authority, with production anticipated in early 2021. The development will be tied back to the existing Buzzard complex.

Golden Eagle Area Development (GEAD)

GEAD, which is operated by CNOOC Europe, is approximately 20 km north of the Buzzard oilfield and consists of the unitization of the Peregrine, Hobby, Golden Eagle and Solitaire discoveries. The development incorporates a production, utilities and accommodation platform, linked to a separate wellhead platform, with first oil achieved in October 2014. The GEAD co-owners also hold adjacent exploration licences and continue to explore the region. The facilities have gross production capacity of approximately 76 mboe/d (20 mboe/d net to Suncor). Drilling activities took place at GEAD during 2018. As at December 31, 2018, there were 20 wells: 15 oil and gas production wells and five water injection wells. In 2018, Suncor's share of GEAD production averaged 12.4 mboe/d (2017 19.6 mboe/d).

Rosebank

During 2018, the company acquired a further 10% interest in the Rosebank project, bringing the company's participating interest in the project to 40% from its previous 30%. This project, which was discovered in December 2004 and is operated by Equinor U.K. Limited (Equinor), is located approximately 130 km northwest of the Shetland Islands, in the U.K. North Sea, in water depths of approximately 1,100 metres. The project is currently in the pre-sanction phase.

Oda

The Oda field (PL405 licence) was discovered in 2011 and is located 13 km east of the producing Ula field in the southern part of the Norwegian North Sea. Spirit Energy is the operator and Suncor has a 30% working interest. The project was sanctioned in November 2016, and the field is being developed with a subsea template tied back to the Ula field. Drilling activities were completed in 2018 and first oil is planned for as early as the second quarter of 2019, with peak production expected to reach 35 mbbls/d (11 mbbls/d net to Suncor). Suncor's share of the post-sanction project cost estimate is approximately $270 million. As at December 31, 2018, there were three wells: two oil and gas production wells and one water injection well.

Fenja

In 2018, Suncor acquired a 17.5% participating interest in the Fenja development project (PL586 licence). The Fenja field, which was discovered in 2014 and is operated by Neptune Energy, is located approximately 30 km southwest of the Equinor-operated Njord field in the Norwegian Sea. The project was sanctioned by the owners in late 2017 and the plan for development and operation was approved by the Royal Norwegian Ministry of Petroleum and Energy in the first half of 2018. The field will be developed with two subsea templates with six wells tied back to the Equinor-operated Njord platform. First oil is planned for 2021, with peak production expected to reach 34 mbbls/d (6 mbbls/d net to Suncor) between 2021 and 2022. Suncor's share of the post-sanction, post-acquisition project cost estimate is approximately $280 million.

Other Assets

Suncor continues to pursue other opportunities offshore of the U.K. and Norway. The company holds interests in 18 exploration licences in these areas.

Other International

Libya

In Libya, Suncor is a signatory to seven EPSAs with the National Oil Corporation (NOC). Five of the seven EPSAs relate to fields with developed production and exploration prospects; the remaining two are exploration EPSAs related to properties that do not contain reserves, one of which is to be relinquished following an unsuccessful exploration program. 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 total oil Suncor receives for cost recovery and its share of excess petroleum is referred to as entitlement volumes. 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.

Since 2013, production and liftings in Libya have been intermittent due to political unrest, and the remaining value of Suncor's assets in Libya was impaired in 2015. Suncor had production and liftings from some of its oilfields in 2018, but others remain shut in due to political unrest. The timing of a return to normal operations in Libya remains uncertain. As a result, the remaining value of Suncor's assets in Libya were written off in 2015.

The estimated cost of Suncor's remaining exploration work program commitment at December 31, 2018, is US$359 million. Suncor declared force majeure for all exploration commitments in Libya effective December 14, 2014, and this declaration remains in effect. Subsequent to the end of 2018, the company received $300 million in risk mitigation proceeds for its Libyan assets (approximately $260 million after-tax). The proceeds may be subject to a provisional repayment which is dependent on the future performance and cash flows from Suncor's Libyan assets.

Suncor's share of production in Libya on an entitlement basis averaged 2.9 mbbls/d in 2018 (2017   4.5 mbbls/d).

Syria

In December 2011, amid continuing unrest in Syria, sanctions were imposed and Suncor declared force majeure under its contractual obligations, suspending 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, although the company believes some assets have sustained significant 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.

Sales of Principal Products

Oil and gas production from East Coast Canada and Offshore U.K. & Norway is either marketed by Suncor's Energy Trading business acting as a marketing agent, or sold to the company's 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:

	2018		2017	
Sales Volumes	**mboe/d**	**% operating revenues**	mboe/d	% operating revenues
E&P Canada				
Crude oil and NGLs	**52.8**	**52**	51.1	43
Natural gas	**0.5**		1.8	
E&P International				
Crude oil and NGLs[(1)]	**48.7**	**47**	66.5	56
Natural gas	**0.8**	**1**	1.4	1
Total Exploration and Production				

Crude oil and NGLs	**101.5**	**99**	117.6	99
Natural gas	**1.3**	**1**	3.2	1

(1) E&P International crude oil and NGLs includes production volumes for Libya on an entitlement basis.

Distribution of Products

East Coast Canada field production is transported by shuttle tanker from offshore installations 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.

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. Natural gas is transported via the third-party operated SAGE Pipeline System to the St. Fergus Gas Terminal in Scotland.

Royalties

East Coast Canada

Terra Nova has reached the net royalty stage, consisting of a two tier profit-sensitive royalty. Tier one is the greater of 10% of gross revenue or 30% of net revenue (gross revenue adjusted for eligible costs). Tier two is an additional 12.5% of net revenue. During 2018, Terra Nova royalties averaged 20% of gross revenue (2017 16%).

Hibernia production from the original oilfields and the AA Block has reached the net royalty stage, consisting of a two tier profit-sensitive royalty and an additional net profits interest (NPI) of 10% of net revenue. Tier one is the greater of 5% of gross revenue or 30% of net revenue. Tier two is an additional 12.5% of net revenue; however, this has not yet been triggered. For the portion of the HSEU that is contained within the original Hibernia licence area, a tier three royalty ranges between 7.5% and 12.5% of net revenue, depending on the price of WTI.

The HSEU royalty structure is similar to the Hibernia arrangement, but is subject to an additional tier three royalty that ranges between 2.5% and 7.5% of net revenue, depending on the price of WTI. The HSEU tier three royalty will coincide with the triggering of the tier one royalty; however, the HSEU is currently at the net royalty stage and is subject to a royalty of the greater of 5% of gross revenue or 30% of net revenue.

During 2018, Hibernia (including the HSEU) royalties and NPI combined to average 23% of gross revenue (2017 26%).

The White Rose base project has reached the net royalty stage, consisting of a two tier profit-sensitive royalty. Tier one is the greater of 7.5% of gross revenue or 20% of net revenue. Tier two is an additional 10% of net revenue. The White Rose Extension tier one and tier two royalty structures are the same as the base project, and there is an additional tier three royalty of 6.5% of net revenue, payable if WTI is greater than US$50/bbl. The White Rose Extension is currently paying tier one and tier three royalties, but has not yet triggered tier two. During 2018, total White Rose royalties averaged 7% of gross revenue (2017 9%).

The Hebron royalty consists of an initial sliding-scale basic royalty, followed by a three-tiered royalty which will become payable upon the achievement of specified levels of profitability. The basic royalty will start at 1% and increase to 7.5% of gross revenue depending on certain milestones. The tier one royalty is equal to 20% of net revenue. The tier two royalty is equal to an additional 10% of net revenue. The tier three royalty is equal to 6.5% of net revenue, payable if WTI is greater than US$50/bbl. During 2018, Hebron royalties averaged 1% of gross revenue (2017 1%).

E&P International

There are no royalties on oil and gas production from Offshore U.K. & Norway; however, oil and gas profits offshore U.K. are subject to a 40% income tax rate. In addition, oil and gas profits offshore Norway are subject to a 78% income tax rate. 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, with a flexible configuration that allows processing of sweet SCO from the company's Oil Sands operations, WCS, conventional crude oil, as well as intermediate feedstock. Crude oil is procured at market prices on a spot basis or under contracts that can be terminated on short notice. Crude oil for the refinery can be supplied through several channels, including via Enbridge's Line 9, the Portland-Montreal Pipeline, by marine transportation, and by rail for inland crudes. The Montreal refinery received inland-sourced crude volumes averaging 124.1 mbbls/d in 2018 (2017 113.7 mbbls/d).

Production 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 continues to produce feedstock sold under a long-term supply contract with HollyFrontier, following the completion of the sale of Suncor's Mississauga lubricants facility in early 2017. Refined products are delivered to distribution terminals and customers via the Trans-Northern Pipeline, truck, rail and marine vessel.

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 372,000 metric tonnes in 2018 (2017 368,000 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 operates Canada's largest ethanol facility, the St. Clair Ethanol plant in the Sarnia-Lambton region of Ontario, with a nameplate capacity of 396 million litres per year. In 2018, the plant produced 402 million litres of ethanol (2017 408 million litres).

Western North America

Edmonton Refinery

The Edmonton refinery has a crude oil capacity of 142 mbbls/d and has the capability to run a full slate of feedstock sourced from Suncor's Oil Sands operations. 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 the other Syncrude joint venture partners' 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 heavy 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 crude 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 throughput capacity of 98 mbbls/d. The refinery processes primarily conventional crude oil, and has the capacity to process up to 16 mbbls/d of sour SCO and diluted bitumen from Suncor's Oil Sands operations. A majority of crude feedstock is supplied from sources in the U.S., including 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. Crude oil is supplied to the Commerce City refinery primarily by 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 and Wyoming. 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, 2018 and 2017.

Average Daily Crude Throughput (mbbls/d, except as noted)	Montreal		Sarnia		Edmonton		Commerce City	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017
Sweet synthetic	**8.9**	7.9	**29.7**	23.0	**50.1**	52.1		
Sour synthetic			**25.7**	35.7	**32.8**	41.7	**9.2**	11.2
Diluted bitumen	**22.1**	24.3			**35.6**	42.1	**11.2**	7.9
Sweet conventional	**90.0**	86.7	**3.1**	1.4			**65.7**	66.3
Sour conventional	**9.2**	6.8	**19.4**	20.7	**4.7**	0.7	**13.4**	12.8
Total	**130.2**	125.7	**77.9**	80.7	**123.2**	136.5	**99.5**	98.3
Utilization (%)	**95**	92	**92**	95	**87**	96	**102**	100
Equity Crude Processed[1]	**7.0**	7.6	**45.0**	48.9	**99.3**	103.8	**9.2**	11.2

(1) Includes Suncor's upstream operations, including its working interest in Syncrude.

Refined Petroleum Production Yield Mix (%)	Montreal		Sarnia		Edmonton		Commerce City	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017
Gasoline	**41**	42	**51**	49	**44**	45	**48**	48
Distillates	**37**	34	**37**	39	**50**	50	**35**	35
Other	**22**	24	**12**	12	**6**	5	**17**	17

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	23.80%	Crude oil	Portland, Maine	Montreal, Quebec
Trans-Northern Pipeline	33.30%	Refined product	Montreal, Quebec	Ontario Ottawa, Toronto & Oakville

Sun-Canadian Pipeline	55.00%	Refined product	Sarnia, Ontario	Ontario Toronto, London & Hamilton
Alberta Products Pipeline	35.00%	Refined product	Edmonton, Alberta	Calgary, Alberta
Rocky Mountain Crude Pipeline	100.00%	Crude oil	Guernsey, Wyoming	Denver, Colorado
Centennial Pipeline	100.00%	Crude oil	Guernsey, Wyoming	Cheyenne, Wyoming
Oil Sands Pipeline	100.00%	Crude oil	Fort McMurray, Alberta	Edmonton, Alberta

Marketing Assets and Operations

Suncor's retail service station network operates nationally in Canada primarily under the Petro-Canada® brand. As at December 31, 2018, this network consisted of 1,528 outlets across Canada. In addition, refined products are marketed through independent dealers and joint operations. Suncor's Canadian retail network had sales of gasoline motor fuels averaging approximately 4.8 million litres per site in 2018 (2017 4.8 million litres) and attracted an estimated 17.9% share (2017 17.5%) of the national retail market.

Suncor's Colorado retail network consists of 44 owned or leased Shell , Exxon or Mobil branded outlets. Suncor also has product supply agreements with 145 Shell®-branded sites in both Colorado and Wyoming, and with 49 Exxon and Mobil -branded sites in Colorado. Marketing activities from the retail network also generate non-petroleum revenues from convenience store sales 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 refined products directly to large industrial and commercial customers and independent marketers.

Retail and Wholesale Summary

Locations	As at December 31 2018	2017
Retail Service Stations Canada		
Petro-Canada® branded	**1 527**	1 516
Sunoco® branded	**1**	1
	1 528	1 517
Retail Service Stations[1] U.S.		
Shell branded retail service stations Colorado/Wyoming	**180**	196
Exxon branded retail service stations Colorado	**40**	26
Mobil branded retail service stations Colorado	**18**	10
	238	232
Wholesale Cardlock Sites Canada		
Petro-Canada®-branded cardlock sites (PETRO-PASS®)	**307**	305

(1) Shell is a registered U.S. trademark of SHELL TRADEMARK MANAGEMENT B.V., and Exxon and Mobil are registered U.S. trademarks of Exxon Mobil Corporation.

Refined Products Sales Volumes

	2018		2017	
Sales Volumes	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	**117.8**		117.5	
Western North America	**127.8**		125.4	
	245.6	**47**	242.9	46
Distillates (includes diesel and heating oils, and aviation jet fuels)				

Eastern North America	**95.8**		86.8	
Western North America	**107.6**		112.5	
	203.4	**39**	199.3	37
Other (includes heavy fuel oil, asphalts, lubricants, petrochemicals, other)				
Eastern North America	**52.7**		62.4	
Western North America	**25.6**		25.9	
	78.3	**15**	88.3	17
	527.3		530.5	

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

Sales volumes can also be impacted when refineries undergo 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, transportation fuels, specialty products and feedstock, natural gas, and electricity and has trading offices in Canada, the U.K. and the U.S. Energy Trading manages open price exposure along the Suncor value chain and provides commodity supply, transportation and storage while optimizing price realizations for Suncor's products. The company's 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 and managing the impacts of external market factors, such as pipeline disruptions or outages at refining customers. The Energy Trading business has entered into contractual arrangements for other midstream infrastructure, such as pipeline, storage capacity and rail access, to optimize delivery of existing and future growth production, while generating earnings on select trading strategies and opportunities.

The Energy Trading business supports the company's Refining and Marketing business by optimizing the supply of crude and NGLs feedstock to the company's four refineries, managing crude inventory levels during refinery turnarounds and periods of unplanned maintenance, as well as managing external impacts from pipeline disruptions. Energy Trading also moves Suncor's refinery production to market and ensures supply to Suncor's branded retail and wholesale marketing channels. The business provides reliable natural gas supply to Suncor's upstream and downstream operations and generates incremental revenue through trading and asset optimization.

Renewable Energy

Suncor's renewable energy investment activities include development, construction and ownership of Suncor-operated and joint venture partner-operated renewable power assets across Canada. This currently includes a portfolio of four operating wind power facilities located in Alberta, Saskatchewan and Ontario with a gross installed capacity of 111 MW. In addition, Suncor has secured a number of sites for potential future wind and solar power projects that are in various stages of development, including the proposed Forty Mile Wind Power project located in southeast Alberta, on approximately 50,000 acres of private land, south and east of the town of Bow Island in the County of Forty Mile.

Suncor's wind power projects as at December 31, 2018:

Wind Power Projects		Ownership Interest (%)	Gross (MW)	Turbines	Completed
Operated by Suncor					
Adelaide	Strathroy, Ontario	75.0	40	18	2014
Non-operated					
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	2018	2017
Oil Sands(1)	**6 289**	6 196
Exploration and Production	**325**	332
Refining and Marketing	**2 787**	2 737
Corporate, Energy Trading and Renewable Energy(2)	**3 079**	3 116
Total	**12 480**	12 381

(1) Includes employees related to the Fort Hills operations.

(2) Includes employees from the company's Projects group, which supports the business units.

In addition to Suncor's employees, the company also uses independent contractors to supply a range of services.

Approximately 32% or 4,216 of the company's employees were covered by collective agreements at the end of 2018. The company completed negotiations in 2018 and collective agreements are now in place with Teamsters Canada at the Burrard terminal and with Unifor for the ETFD. Negotiations are in progress for the 11 collective agreements, representing approximately 3,954 employees, set to expire in 2019, including: Oil Sands Base and Firebag, that represent approximately 3,056 employees; the Edmonton refinery; the Montreal refinery; the Commerce City refinery; the Burrard, Edmonton, London, Montreal and Oakville terminals; and Terra Nova.

ETHICS, SOCIAL AND ENVIRONMENTAL POLICIES

Suncor has adopted several policies focused on ethics, social and environmental matters.

Suncor's standards for the ethical conduct of the company's business are set forth in a Standards of Business Conduct Code (the Code), which applies to Suncor's directors, officers, employees and independent contractors, and requires strict compliance with legal requirements and Suncor's values. 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 independent contractor is required to annually complete a Code training course, read a summary of the Code, affirm that they understand the requirements of the Code, and provide confirmation of compliance with the Code since their last affirmation 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 Governance Committee of the Board of Directors. A copy of the Code is available on Suncor's website at www.suncor.com.

Suncor has a Supplier Code of Conduct that highlights the values that are important to Suncor and is a guide to the standard of behaviour required of all suppliers, contractors, consultants and other third parties with whom Suncor does business. The Supplier Code of Conduct addresses topics such as safety, human rights, harassment, bribery and corruption, and confidential information, among others. It also reinforces Suncor's commitment to sustainable development and encourages Suncor's business associates to work with the company to seek ways to reduce environmental impacts, support the communities in which Suncor works and collectively achieve economic growth. Compliance with the Supplier Code of Conduct is a standard requirement for all Suncor supply chain contracts.

Suncor has a Human Rights Policy, which affirms Suncor's responsibility to respect human rights and is intended to ensure 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 contains guiding principles, including: the belief that a process for human rights impact assessment undertaken regularly is essential to identify, prevent, mitigate and remedy potential impacts on human rights: a commitment to providing a working environment that is free from harassment, violence, intimidation and

other disruptive behaviours; a commitment to respecting the cultures, customs and values of the communities in which the company operates; the belief that security policies should be consistent with international human rights standards; and the belief that employees and stakeholders affected by the company's activities should have access to grievance mechanisms that are legitimate, accessible, predictable, equitable and transparent. The policy makes clear that the scope of Suncor's human rights due diligence includes its own operations and, where it can influence its 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 states Suncor's belief that successful stakeholder relations provide significant mutual benefits, including enabling 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 create shared value. The policy sets the foundation for 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 commitment to be a sustainable energy company by working to achieve or exceed levels of performance governed by legislation and by the evolving environmental, social and economic expectations of the company's stakeholders. The policy reflects Suncor's belief that the company's EH&S efforts are complementary and interdependent with the company's economic and social performance. The policy states that Suncor management is responsible for ensuring that employees and contractors 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 (EHS&SD) Committee of the Board of Directors meets quarterly to review Suncor's effectiveness in meeting its EHS&SD obligations. The committee also reviews the company's strategies and policies, with respect to EHS&SD, given legal, industry and community standards. The EHS&SD Committee also monitors management's performance and emerging trends and issues in these areas. In addition, the EHS&SD Committee has oversight over Suncor's performance with respect to the company's social goal regarding building mutual trust and respect with the Aboriginal Peoples of Canada, and reviews Suncor's annual Report on Sustainability, reporting on Suncor's EHS&SD progress, plans and performance objectives, as well as disclosure on lobbying.

Suncor's annual President's Operational Excellence Awards support and highlight the goals of the EH&S policy by honouring employees and contractors who demonstrate an exceptional commitment to EH&S performance. The awards ceremony highlights progress on safety initiatives and provides educational opportunities for all employees.

The aforementioned policies are reviewed regularly, and are accessible to employees and contractors on the company's intranet. Additional workshops and targeted training sessions on various matters under the policies are also conducted as warranted throughout the year. The Canadian Aboriginal Relations Policy is available in Cree and Dene audio translations.

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 28, 2019, with an effective date of December 31, 2018. Reserves evaluations have not been updated since the effective date and, thus, do not reflect changes in the company's reserves since that date. The preparation date of the information is February 22, 2019.

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 included 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 dated February 22, 2019 (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 (collectively, E&P Canada), and conventional assets offshore of the U.K. and Norway (collectively, Offshore U.K. & Norway), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule), contained in their reports dated February 22, 2019 (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 crude oil and medium crude oil (combined, including immaterial amounts of heavy crude oil) and conventional natural gas (including immaterial amounts of NGLs) reserves and the net present values of future net revenues for these reserves using forecast prices and costs prior to provision for interest and general and administrative expense.

Advisories Reserves Data

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 cost assumptions will be attained and variances could be material. There is no guarantee that the estimates for SCO, bitumen, light crude oil and medium crude oil, heavy crude oil, conventional natural gas and NGLs reserves provided herein will be recovered. Actual SCO, bitumen, light crude oil and medium crude oil, heavy crude oil, conventional natural gas and NGLs volumes recovered may be greater than or less than the estimates provided herein. Readers should review the Glossary of Terms and Abbreviations and the definitions and information contained in the Notes to Reserves Data Tables, Definitions for Reserves Data Tables and Notes to Future Net Revenues Tables in conjunction with the following notes and tables.

Significant Risk Factors and Uncertainties Affecting Reserves

The evaluation of reserves is a continuous process, one that can be significantly impacted by a variety of internal and external influences. Revisions are often required as a result of newly acquired technical data, technology improvements, or changes in historical performance, pricing, economic conditions, market availability, or regulatory requirements. Additional technical information regarding geology, hydro geology, reservoir properties and reservoir fluid properties is 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 development. Royalty regimes and environmental regulations and other regulatory changes 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. Political unrest, such as is occurring in Syria and Libya, has resulted in volumes that would otherwise be classified as reserves being classified as contingent resources.

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

The reserves included in this AIF represent estimates only. There are numerous uncertainties inherent in estimating quantities and quality of these reserves, including many factors beyond the company's control. In general, estimates of reserves and the future net cash flows from these reserves are based upon a number of variable factors and assumptions such as production forecasts, regulations, pricing, the timing and amount of capital expenditures, future royalties, future operating costs, yield rates for upgraded production of SCO from bitumen, and future abandonment and reclamation costs all of which may vary considerably from actual results and may be affected by many of the factors identified under Industry Conditions and Risk Factors herein. The accuracy of any reserves estimate 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 reserves and categorization of such reserves based on the certainty of recovery, prepared by different engineers or by the same engineers at different times, may vary.

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

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

Specific significant risk factors and uncertainties affecting Suncor's reserves include, among others:

Volatility of Commodity Prices

Commodity pricing affects the profitability of reserves development. For example, higher commodity prices may result in higher reserves by making more projects economically viable or extending their economic life; conversely, lower commodity prices may result in lower reserves. Low commodity prices could have a material adverse effect on Suncor's reserves. Refer to the Risk Factors Volatility of Commodity Prices section of this AIF.

Carbon Risk

Suncor operates in jurisdictions that have regulated, or have proposed to regulate, industrial GHG emissions, including the laws enacted by the Government of Alberta impacting Suncor's current and future Oil Sands assets, a summary of which is set forth in the Industry Conditions Environmental Regulation Climate Change section of this AIF. Such laws could impose significant compliance costs on Suncor, which could potentially impact the economic viability of certain projects recorded as reserves, or could require that new technologies be developed. Future development could be adversely impacted if compliance costs result in projects not being economically viable or if required technologies are not developed. Refer to the Risk Factors Carbon Risk section of this AIF.

Political Unrest

As a result of political unrest in Syria, Suncor reclassified all Syria reserves to contingent resources, effective December 31, 2012. Suncor also reclassified all Libya reserves to contingent resources, effective December 31, 2016, due to political unrest in Libya. All Syria and Libya volumes remain classified as contingent resources as at December 31, 2018. The criteria for the reclassification of the aforementioned volumes back to reserves include sustained periods of political stability, operational and production stability, and normalization of business relations including financial transactions. Refer to the Risk Factors Foreign Operations section of this AIF.

Abandonment and Reclamation costs

Refer to the Additional Information Relating to Reserves Data Abandonment and Reclamation Costs section of this AIF.

Government Action

Government intervention, including mandatory production curtailments, could create long-term market uncertainty, which could have a material adverse effect on Suncor's reserves. Refer to the Risk Factors Government/Regulatory and Policy Effectiveness section of this AIF.

Refer to the Risk Factors section of this AIF for additional information on significant risk factors and uncertainties affecting Suncor's reserves.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves[1]
as at December 31, 2018
(forecast prices and costs)[2]

	SCO[3] (mmbbls)		Bitumen (mmbbls)		Light Crude & Medium Crude Oil[4] (mmbbls)		Conventional Natural Gas (bcfe)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing										
Mining	2 069	1 852	942	842					3 011	2 694
In Situ	180	160	118	104					298	264
E&P Canada					61	49			61	49
Total Canada	2 249	2 011	1 059	947	61	49			3 370	3 007
Offshore U.K. & Norway					43	43	1	1	43	43
Total Proved Developed Producing	**2 249**	**2 011**	**1 059**	**947**	**104**	**92**	**1**	**1**	**3 413**	**3 050**
Proved Developed Non-Producing										
Mining										
In Situ										
E&P Canada										
Total Canada										
Offshore U.K. & Norway										
Total Proved Developed Non-Producing										
Proved Undeveloped										
Mining										
In Situ	548	453	653	532					1 201	985
E&P Canada					62	59			62	59
Total Canada	548	453	653	532	62	59			1 263	1 044
Offshore U.K. & Norway					8	8	13	13	10	10
Total Proved Undeveloped	**548**	**453**	**653**	**532**	**70**	**67**	**13**	**13**	**1 273**	**1 054**
Proved										
Mining	2 069	1 852	942	842					3 011	2 694
In Situ	729	613	770	636					1 499	1 249
E&P Canada					123	108			123	108
Total Canada	2 798	2 465	1 712	1 478	123	108			4 632	4 051

Offshore U.K. & Norway					52	52	14	14	54	54
Total Proved	**2 798**	**2 465**	**1 712**	**1 478**	**174**	**159**	**14**	**14**	**4 686**	**4 105**
Probable										
Mining	621	547	496	397					1 117	944
In Situ	1 175	923	387	284					1 562	1 207
E&P Canada					174	138			174	138
Total Canada	1 796	1 469	883	681	174	138			2 853	2 288
Offshore U.K. & Norway					37	37	17	17	40	40
Total Probable	**1 796**	**1 469**	**883**	**681**	**211**	**175**	**17**	**17**	**2 892**	**2 328**
Proved Plus Probable										
Mining	2 690	2 398	1 438	1 239					4 128	3 638
In Situ	1 904	1 535	1 157	920					3 061	2 455
E&P Canada					297	246			297	246
Total Canada	4 593	3 934	2 595	2 159	297	246			7 485	6 339
Offshore U.K. & Norway					88	88	32	32	94	94
Total Proved Plus Probable	**4 593**	**3 934**	**2 595**	**2 159**	**385**	**334**	**32**	**32**	**7 579**	**6 433**

Please see Notes (1) through (4) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Reserves[1]
as at December 31, 2018
(forecast prices and costs)[2]

	SCO[3]			Bitumen			Light Crude & Medium Crude Oil[4][5]			Conventional Natural Gas[6]			Total	
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe
Mining														
December 31, 2017	2 134	608	2 741	929	581	1 510							3 062	1 189
Extensions & Improved Recovery[7]														
Technical Revisions[8]	(11)	(25)	(36)	18	(94)	(76)							7	(120)
Discoveries[9]														
Acquisitions[10]	73	38	112	19	10	29							92	48
Dispositions[11]														
Economic Factors[12]														
Production[13]	(127)		(127)	(24)		(24)							(151)	
December 31, 2018	**2 069**	**621**	**2 690**	**942**	**496**	**1 438**							**3 011**	**1 117**
In Situ														
December 31, 2017	751	1 216	1 967	805	342	1 147							1 557	1 558
Extensions & Improved Recovery[7]	1		1										1	
Technical Revisions[8]	9	(41)	(32)	10	45	55							19	4
Discoveries[9]														
Acquisitions[10]														

Dispositions[11]														
Economic Factors[12]														
Production[13]	(33)		(33)	(45)		(45)							(78)	
December 31, 2018	**729**	**1 175**	**1 904**	**770**	**387**	**1 157**							**1 499**	**1 562**
E&P Canada														
December 31, 2017							98	227	326	21	6	28	102	228
Extensions & Improved Recovery[7]							2	2	5				2	2
Technical Revisions[8]							42	(56)	(13)				42	(56
Discoveries[9]														
Acquisitions[10]														
Dispositions[11]										20	6	27	3	1
Economic Factors[12]														
Production[13]							(20)		(20)	(1)		(1)	(20)	
December 31, 2018							**123**	**174**	**297**				**123**	**174**
Total Canada														
December 31, 2017	2 885	1 823	4 708	1 734	923	2 657	98	227	326	21	6	28	4 721	2 975
Extensions & Improved Recovery[7]	1		1				2	2	5				4	3
Technical Revisions[8]	(2)	(66)	(68)	28	(50)	(22)	42	(56)	(13)				68	(172
Discoveries[9]														
Acquisitions[10]	73	38	112	19	10	29							92	48

Dispositions[11]										20	6	27	3	1
Economic Factors[12]														
Production[13]	(160)		(160)	(69)		(69)	(20)		(20)	(1)		(1)	(249)	
December 31, 2018	**2 798**	**1 796**	**4 593**	**1 712**	**883**	**2 595**	**123**	**174**	**297**				**4 632**	**2 853**

Please see Notes (1) through (13) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Reserves[1] *(continued)*
as at December 31, 2018
(forecast prices and costs)[2]

	SCO[3]			Bitumen			Light Crude & Medium Crude Oil[4][5]			Conventional Natural Gas[6]			Total	
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probab
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmb
Offshore U.K. & Norway														
December 31, 2017							57	34	91	2	4	6	57	3
Extensions & Improved Recovery[7]							2	3	5	1	1	2	2	
Technical Revisions[8]							3	(6)	(3)	1	(1)		3	(
Discoveries[9]									1				1	
Acquisitions[10]							6	5	11	12	14	26	8	
Dispositions[11]														
Economic Factors[12]							1		1				1	
Production[13]							(17)		(17)	(2)		(2)	(17)	
December 31, 2018							**52**	**37**	**88**	**14**	**17**	**32**	**54**	**4**
Other International [14]														
December 31, 2017														
Extensions & Improved Recovery[7]														
Technical Revisions[8]							5		5				5	
Discoveries[9]														

Acquisitions(10)														
Dispositions(11)														
Economic Factors(12)														
Production(13)(14)							(5)		(5)				(5)	
December 31, 2018														
Total														
December 31, 2017	2 885	1 823	4 708	1 734	923	2 657	155	261	417	24	10	34	4 778	3 00
Extensions & Improved Recovery(7)	1		1				4	6	9	1	1	2	5	
Technical Revisions(8)	(2)	(66)	(68)	28	(50)	(22)	50	(61)	(11)	1	(1)		77	(17
Discoveries(9)									1				1	
Acquisitions(10)	73	38	112	19	10	29	6	5	11	12	14	26	100	5
Dispositions(11)										20	6	27	3	
Economic Factors(12)							1		1				1	
Production(13)	(160)		(160)	(69)		(69)	(42)		(42)	(3)		(3)	(272)	
December 31, 2018	**2 798**	**1 796**	**4 593**	**1 712**	**883**	**2 595**	**174**	**211**	**385**	**14**	**17**	**32**	**4 686**	**2 89**

Please see Notes (1) through (14) 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, 2018

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

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

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

(4) Gross volumes of Light Crude & Medium Crude Oil for E&P Canada include immaterial quantities of Heavy Crude Oil as follows: Proved Developed Producing of 15 mmbbls, Proved Undeveloped of 46 mmbbls, Proved of 61 mmbbls, Probable of 39 mmbbls and Proved Plus Probable of 100 mmbbls. Net volumes of Light Crude & Medium Crude Oil for E&P Canada include immaterial quantities of Heavy Crude Oil as follows: Proved Developed Producing of 14 mmbbls, Proved Undeveloped of 45 mmbbls, Proved of 59 mmbbls, Probable of 30 mmbbls and Proved Plus Probable of 90 mmbbls.

(5) Light Crude & Medium Crude Oil Technical Revisions for E&P Canada include quantities of Heavy Crude Oil as follows: Proved of 29 mmbbls, Probable of (35) mmbbls and Proved Plus Probable of (5) mmbbls.

(6) Conventional Natural Gas includes immaterial amounts of NGLs (0.7 mmbbls of Proved and 1.3 mmbbls of Proved Plus Probable NGLs).

(7) Extensions & 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 transfer of Probable reserves to Proved reserves. Changes in 2018 are primarily a result of E&P drilling activities.

(8) Technical Revisions include changes in previous estimates resulting from new technical data or revised interpretations. Changes in 2018 are primarily due to new information obtained during the year, including drilling results and ongoing field performance, and the movement of a portion of E&P Canada volumes from Probable to Proved as a result of offshore drilling activity. For Other International, a technical revision has been made to offset production (refer to Note 14 below).

(9) Discoveries are additions to reserves in reservoirs where no reserves were previously booked and are as a result of the confirmation of the existence of an accumulation of a significant quantity of potentially recoverable petroleum. Additions in 2018 relate to GEAD within Offshore U.K. & Norway.

(10) Acquisitions are additions to reserves estimates as a result of purchasing interests in oil and gas properties. Additions in 2018 within Mining relate to Suncor's acquisition of an additional 5% interest in Syncrude and an additional 1.05% interest in Fort Hills. Additions in 2018 within Offshore U.K. & Norway relate to the acquisition of a 17.5% interest in the Fenja development project.

(11) Dispositions are reductions in reserves estimates as a result of selling all or a portion of an interest in oil and gas properties. During 2018, the company disposed of its northeast B.C. mineral landholdings, including associated production.

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

(13) Production quantities may include estimated production for periods near the end of the year when actual sales quantities were not available at the time the reserves evaluations were conducted.

(14) Other International includes production for Libya based on the company's 50% working interest. Production for Libya is offset by Technical Revisions of an equal amount, since Suncor's Libya assets are classified as contingent resources due to political unrest.

Definitions for Reserves Data Tables

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

Gross means:

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

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

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

Net means:

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

(b) in relation to Suncor's interest in 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) for mining assets, through installed extraction equipment and infrastructure that is operational at the time of the reserves estimate. 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.

For any given pool, 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.

Future Net Revenues Tables and Notes[1]

Net Present Values of Future Net Revenues Before Income Taxes
as at December 31, 2018
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value[2]
	0%	5%	10%	15%	20%	($/boe)
Proved Developed Producing						
Mining	50 836	36 575	25 102	18 087	13 701	9.32
In Situ	8 430	7 609	6 897	6 297	5 793	26.14
E&P Canada	1 560	1 571	1 529	1 469	1 405	31.34
Total Canada	60 826	45 755	33 528	25 854	20 899	11.15
Offshore U.K. & Norway	1 984	1 936	1 858	1 771	1 685	42.78
Total Proved Developed Producing	**62 810**	**47 691**	**35 386**	**27 624**	**22 584**	**11.60**
Proved Developed Non-Producing						
Mining						
In Situ						
E&P Canada						
Total Canada						
Offshore U.K. & Norway	28	27	26	25	24	74.33
Total Proved Developed Non-Producing	**28**	**27**	**26**	**25**	**24**	**74.33**
Proved Undeveloped						
Mining						
In Situ	33 449	18 369	10 850	6 802	4 465	11.02
E&P Canada	3 197	2 586	2 085	1 702	1 412	35.34
Total Canada	36 646	20 955	12 936	8 505	5 877	12.39
Offshore U.K. & Norway	341	247	172	114	68	16.97
Total Proved Undeveloped	**36 987**	**21 202**	**13 108**	**8 619**	**5 945**	**12.43**
Proved						
Mining	50 836	36 575	25 102	18 087	13 701	9.32
In Situ	41 879	25 978	17 748	13 099	10 258	14.21
E&P Canada	4 757	4 157	3 615	3 172	2 817	33.53
Total Canada	97 472	66 711	46 464	34 358	26 776	11.47

Offshore U.K. & Norway	2 354	2 209	2 056	1 910	1 777	38.12
Total Proved	**99 826**	**68 920**	**48 520**	**36 268**	**28 553**	**11.82**
Probable						
Mining	33 292	13 583	7 153	4 479	3 135	7.58
In Situ	74 178	21 661	8 602	4 511	2 900	7.13
E&P Canada	7 811	4 994	3 342	2 339	1 689	24.19
Total Canada	115 281	40 238	19 098	11 329	7 724	8.35
Offshore U.K. & Norway	2 333	1 922	1 589	1 332	1 133	39.96
Total Probable	**117 615**	**42 160**	**20 687**	**12 660**	**8 856**	**8.89**
Proved Plus Probable						
Mining	84 128	50 158	32 255	22 566	16 836	8.87
In Situ	116 057	47 640	26 350	17 611	13 158	10.73
E&P Canada	12 568	9 151	6 957	5 510	4 506	28.28
Total Canada	212 753	106 948	65 562	45 687	34 500	10.34
Offshore U.K. & Norway	4 687	4 131	3 645	3 241	2 910	38.90
Total Proved Plus Probable	**217 440**	**111 080**	**69 207**	**48 928**	**37 410**	**10.76**

Please see the Notes at the end of the Future Net Revenues Tables.

Net Present Values of Future Net Revenues After Income Taxes[1]
as at December 31, 2018
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	37 129	28 239	19 613	14 244	10 876
In Situ	6 306	5 718	5 193	4 744	4 365
E&P Canada	1 418	1 437	1 402	1 348	1 289
Total Canada	44 853	35 394	26 207	20 335	16 530
Offshore U.K. & Norway	938	964	952	924	890
Total Proved Developed Producing	**45 791**	**36 358**	**27 160**	**21 259**	**17 419**
Proved Developed Non-Producing					
Mining					
In Situ					
E&P Canada					
Total Canada					
Offshore U.K. & Norway	17	16	16	15	15
Total Proved Developed Non-Producing	**17**	**16**	**16**	**15**	**15**
Proved Undeveloped					
Mining					
In Situ	24 127	13 048	7 564	4 637	2 962
E&P Canada	2 462	2 003	1 609	1 305	1 073
Total Canada	26 589	15 051	9 174	5 942	4 035
Offshore U.K. & Norway	327	239	169	114	71
Total Proved Undeveloped	**26 917**	**15 289**	**9 343**	**6 056**	**4 106**
Proved					
Mining	37 129	28 239	19 613	14 244	10 876
In Situ	30 433	18 766	12 757	9 381	7 326
E&P Canada	3 880	3 439	3 011	2 652	2 362
Total Canada	71 442	50 445	35 381	26 277	20 564
Offshore U.K. & Norway	1 282	1 219	1 137	1 054	976

Total Proved	**72 725**	**51 664**	**36 518**	**27 331**	**21 540**
Probable					
Mining	24 441	9 838	5 079	3 129	2 164
In Situ	53 964	15 660	6 243	3 310	2 151
E&P Canada	5 638	3 615	2 372	1 613	1 124
Total Canada	84 043	29 113	13 694	8 051	5 440
Offshore U.K. & Norway	1 222	1 078	932	807	706
Total Probable	**85 265**	**30 192**	**14 626**	**8 858**	**6 145**
Proved Plus Probable					
Mining	61 570	38 077	24 692	17 373	13 040
In Situ	84 397	34 426	19 000	12 691	9 477
E&P Canada	9 518	7 055	5 383	4 265	3 486
Total Canada	155 485	79 558	49 075	34 329	26 004
Offshore U.K. & Norway	2 505	2 298	2 069	1 861	1 681
Total Proved Plus Probable	**157 990**	**81 856**	**51 144**	**36 189**	**27 685**

Please see the Notes at the end of the Future Net Revenues Tables.

Total Future Net Revenues[1]
as at December 31, 2018
(forecast prices and costs)

(in $ millions, undiscounted)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	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	266 600	29 775	132 344	33 566	20 079	50 836	13 706	37 129
In Situ	20 524	2 321	7 557	1 717	499	8 430	2 124	6 306
E&P Canada	5 513	1 089	1 407	188	1 269	1 560	142	1 418
Total Canada	292 636	33 185	141 307	35 470	21 848	60 826	15 973	44 853
Offshore U.K. & Norway	3 871		1 238	76	572	1 984	1 047	938
Total Proved Developed Producing	**296 507**	**33 185**	**142 545**	**35 546**	**22 420**	**62 810**	**17 020**	**45 791**
Proved Developed Non-Producing								
Mining								
In Situ								
E&P Canada								
Total Canada								
Offshore U.K. & Norway	29		1			28	11	17
Total Proved Developed Non-Producing	**29**		**1**			**28**	**11**	**17**
Proved Undeveloped								
Mining								
In Situ	100 228	17 722	30 420	17 581	1 057	33 449	9 321	24 127
E&P Canada	5 784	265	1 053	686	584	3 197	735	2 462
Total Canada	106 012	17 987	31 473	18 266	1 640	36 646	10 057	26 589
Offshore U.K. & Norway	911		171	341	58	341	14	327
Total Proved Undeveloped	**106 923**	**17 987**	**31 643**	**18 608**	**1 698**	**36 987**	**10 070**	**26 917**
Proved								
Mining	266 600	29 775	132 344	33 566	20 079	50 836	13 706	37 129

In Situ	120 752	20 043	37 977	19 298	1 556	41 879	11 446	30 433
E&P Canada	11 297	1 353	2 460	873	1 853	4 757	877	3 880
Total Canada	398 648	51 171	172 780	53 737	23 488	97 472	26 030	71 442
Offshore U.K. & Norway	4 811		1 410	417	630	2 354	1 072	1 282
Total Proved	**403 459**	**51 171**	**174 190**	**54 154**	**24 119**	**99 826**	**27 101**	**72 725**
Probable								
Mining	123 949	19 657	57 538	9 956	3 506	33 292	8 852	24 441
In Situ	202 574	43 021	54 461	29 556	1 358	74 178	20 214	53 964
E&P Canada	18 557	3 821	4 197	1 941	787	7 811	2 173	5 638
Total Canada	345 079	66 498	116 197	41 452	5 651	115 281	31 239	84 043
Offshore U.K. & Norway	3 754		988	282	150	2 333	1 111	1 222
Total Probable	**348 833**	**66 498**	**117 184**	**41 735**	**5 802**	**117 615**	**32 349**	**85 265**
Proved Plus Probable								
Mining	390 549	49 432	189 882	43 521	23 585	84 128	22 558	61 570
In Situ	323 325	63 063	92 438	48 854	2 914	116 057	31 659	84 397
E&P Canada	29 853	5 174	6 657	2 814	2 640	12 568	3 051	9 518
Total Canada	743 727	117 669	288 977	95 189	29 140	212 753	57 268	155 485
Offshore U.K. & Norway	8 565		2 397	699	781	4 687	2 183	2 505
Total Proved Plus Probable	**752 292**	**117 669**	**291 374**	**95 888**	**29 920**	**217 440**	**59 451**	**157 990**

Please see the Notes at the end of the Future Net Revenues Tables.

Future Net Revenues by Product Type[1]
as at December 31, 2018
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	Unit Value $/boe[2]
Proved Developed Producing		
SCO	24 155	12.01
Bitumen	7 844	8.29
Light Crude & Medium Crude Oil	2 620	33.69
Heavy Crude Oil	761	53.50
Conventional Natural Gas[3]	6	24.12
Total Proved Developed Producing	**35 386**	**11.60**
Proved		
SCO	30 190	12.25
Bitumen	12 659	8.56
Light Crude & Medium Crude Oil	3 168	31.67
Heavy Crude Oil	2 466	41.59
Conventional Natural Gas[3]	36	15.06
Total Proved	**48 520**	**11.82**
Proved Plus Probable		
SCO	44 114	11.21
Bitumen	14 491	6.71
Light Crude & Medium Crude Oil	7 278	29.72
Heavy Crude Oil	3 221	35.97
Conventional Natural Gas[3]	104	19.62
Total Proved Plus Probable	**69 207**	**10.76**

(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) Conventional natural gas includes associated 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 pricing of the respective products, maintenance, fluctuations in production from mining and extraction operations, or changes in the company's overall Oil Sands development strategy.

In Situ future net revenues disclosed above include estimates of production volumes upgraded to SCO and the associated estimated future sales prices and upgrader operating and sustaining capital costs, based on estimates of upgrader capacity available for processing In Situ volumes. For total Proved Plus Probable reserves, approximately 46% to 60% of Firebag bitumen production is estimated to be upgraded to SCO from 2019 to 2035 and 100% thereafter. These assumptions have resulted in a $2.7 billion increase in the net present value of future net revenues (total Proved Plus Probable reserves, before tax, discounted at 10%) attributable to 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.

Forecast Prices and Costs

The forecast price and cost assumptions include changes in wellhead selling prices, take into account escalation with respect to future operating and capital costs, and assume the continuance of current laws and regulations. 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, were derived using averages of forecasts developed by GLJ, Sproule and McDaniel & Associates Consultants Ltd., all of whom are independent qualified reserves evaluators, dated January 1, 2019. Resultant forecasts are set out below. To the extent there are fixed or presently determinable future prices 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 have been incorporated into the forecast prices as applied to the pertinent properties. Benchmark forecast prices have been adjusted for quality differentials and transportation costs applicable to the specific evaluation areas and products. The inflation rates utilized in cost forecasts were 0.0% in 2019 and 2.0% in 2020 and thereafter.

Prices Impacting Reserves Tables

Forecast	Brent North Sea[1]	WTI Cushing Oklahoma	WCS Hardisty Alberta[2]	Light Sweet Edmonton Alberta[3]	Pentanes Plus Edmonton Alberta[4]	AECO Gas[5]	National Balancing Point North Sea[6]
Year	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu
2018[7]	71.45	64.77	49.85	69.54	79.06	1.50	7.09
2019	65.92	58.58	51.55	67.30	70.10	1.88	10.44
2020	69.47	64.60	59.58	75.84	79.21	2.31	9.94
2021	71.65	68.20	65.89	80.17	83.33	2.74	9.62
2022	73.72	71.00	68.61	83.22	86.20	3.05	9.48
2023	75.58	72.81	70.53	85.34	88.16	3.21	9.50
2024	77.39	74.59	72.34	87.33	90.20	3.31	9.55
2025	79.27	76.42	74.31	89.50	92.43	3.39	9.62
2026	81.27	78.40	76.44	91.89	94.87	3.46	9.81
2027	82.88	79.98	78.10	93.76	96.80	3.54	10.00
2028	84.54	81.59	79.81	95.68	98.79	3.62	10.14
2029	86.21	83.22	81.40	97.57	100.74	3.69	10.34
2030	87.93	84.87	83.00	99.52	102.75	3.77	10.54
2031	89.68	86.57	84.69	101.52	104.82	3.84	10.75
2032	91.49	88.30	86.37	103.55	106.92	3.91	10.97
2033	93.32	90.08	88.11	105.65	109.07	3.99	11.19
2034+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

(1) Price used when determining offshore light crude oil and medium crude oil and heavy crude oil reserves for E&P Canada and Offshore U.K. & Norway reserves.

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

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

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

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

(6) Price used when determining conventional natural gas reserves presented as Offshore U.K. & Norway reserves.

(7) Prices for 2018 reflect the company's historical weighted average prices.

Forecast Foreign Exchange Rates Impacting Forecast Prices

Forecast Year	US$/Cdn$ Exchange Rate	Cdn$/€ Exchange Rate	Cdn$/£ Exchange Rate
2019	0.757	1.507	1.668
2020	0.782	1.471	1.631
2021	0.797	1.443	1.600
2022	0.803	1.432	1.587
2023	0.807	1.426	1.581
2024+	0.808	1.423	1.577

Disclosure of Net Present Values of future Net Revenues After Income Taxes

Values presented in the table for Net Present Values of Future Net Revenues After Income Taxes reflect income tax burdens of assets at an individual asset level (for In Situ) or at a business area or legal entity level (for Mining, E&P Canada and Offshore U.K & Norway) based on tax pools associated with that business area or legal entity. 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 total future net revenues table may not provide an estimate of the value at the corporate entity level, which may be significantly different. The 2018 audited Consolidated Financial Statements and the MD&A should be consulted for information on income taxes at the corporate entity level.

Additional Information Relating to Reserves Data

Future Development Costs[1]
as at December 31, 2018
(forecast prices and costs)

($ millions)	2019	2020	2021	2022	2023	Remainder	Total	Discounted At 10%
Proved								
Mining	2 247	2 260	2 089	2 030	2 156	22 784	33 566	16 725
In Situ	788	633	1 162	464	802	15 449	19 298	7 825
E&P Canada	127	169	102	143	123	209	873	641
Total Canada	3 161	3 062	3 353	2 637	3 080	38 443	53 737	25 192
Offshore U.K. & Norway	197	106	61	6	8	39	417	392
Total Proved	3 358	3 168	3 414	2 643	3 088	38 482	54 154	25 583
Proved Plus Probable								
Mining	2 458	2 490	2 303	2 261	2 588	31 421	43 521	19 459
In Situ	702	628	783	512	785	45 443	48 854	8 878
E&P Canada	649	568	357	306	236	697	2 814	2 076
Total Canada	3 809	3 686	3 444	3 079	3 610	77 561	95 189	30 413
Offshore U.K. & Norway	386	161	62	8	10	73	699	657
Total Proved Plus Probable	4 195	3 847	3 506	3 087	3 620	77 634	95 888	31 071

(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 2019 are expected to include:

Mining development activities include capital investments expected to maintain the production capacity of existing facilities, including, but not limited to, tailings infrastructure, major maintenance, truck and shovel replacement, the replenishment of catalysts in hydrotreating units at the upgraders and improvements to utilities, roads and other facilities, and the implementation of technologies expected to reduce costs including AHS.

For both Firebag and MacKay River operations within In Situ, the drilling of new well pairs, as well as the design and construction of new well pads that are expected to maintain existing production levels in future years.

For E&P Canada, development of the WWRP, and development drilling at Hibernia, White Rose, Terra Nova and Hebron.

For E&P International, development of the Norwegian Oda and Fenja projects, as well as development drilling at Buzzard.

Future development costs disclosed above are associated with reserves as evaluated by GLJ and Sproule and are subject to change based on many factors, including economic conditions. Management currently believes that internally generated cash flows, existing and future credit facilities, issuing commercial paper and accessing capital markets will be 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 provided by operating activities.

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

Abandonment and Reclamation Costs

The company completes an annual review of its consolidated abandonment and reclamation cost estimates. The 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, 2018, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs for its upstream assets to be approximately $13.0 billion (discounted at 10%, approximately $2.9 billion) excluding

Refining and Marketing liabilities ($0.2 billion, undiscounted and uninflated). Abandonment and reclamation costs are limited to current disturbances at December 31, 2018 for Suncor's assets, except for Syncrude, which is estimated on a life of mine basis, where it is assumed that material from future disturbances will be required to settle the existing obligation at December 31, 2018. Suncor estimates that it will incur $1.4 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2019 $0.5 billion, 2020 $0.5 billion, 2021 $0.4 billion), more than 75% of which is associated with Oil Sands mining operations.

The abandonment and reclamation cost estimates included in the net present values of the company's Proved and Probable reserves include costs related to the reclamation of disturbed land from oil sands mining activities, future mining disturbances, the treatment of legacy oil sands tailings, the decommissioning of oil sands and natural gas processing facilities and well pads, existing and future reserve wells and associated service wells, disturbed lease sites, and future lease site disturbances. Approximately $29.9 billion (inflated and undiscounted) has been deducted as abandonment and reclamation costs in estimating the future net revenues from Proved Plus Probable reserves, including $26.5 billion related to the company's oil sands upgraders, extraction facilities, tailings ponds, subsurface wells and central processing facilities, which includes amounts related to current disturbances.

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 in the year when the events first occurred.

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

	2016		2017		**2018**	
	First Attributed	Total as at December 31, 2016	First Attributed	Total as at December 31, 2017	**First Attributed**	**Total as at December 31, 2018**
SCO (mmbbls)						
Mining						
In Situ		576		575		**548**
Total SCO		576		575		**548**
Bitumen (mmbbls)						
Mining		879	40	929		
In Situ		694		675		**653**
Total Bitumen		1 573	40	1 603		**653**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada	1	19	1	13	**1**	**15**
Offshore U.K. & Norway					**8**	**8**
Total Light Crude & Medium Crude Oil	1	19	1	13	**9**	**23**
Heavy Crude Oil (mmbbls)						
E&P Canada		27		34		**46**
Offshore U.K. & Norway						
Total Heavy Crude Oil		27		34		**46**
Conventional Natural Gas (bcfe)						
E&P Canada						
Offshore U.K. & Norway[2]					**13**	**13**
Total Conventional Natural Gas					**13**	**13**
Total (mmboe)	1	2 195	41	2 226	**11**	**1 273**

(1) Figures may not add due to rounding.

(2) Includes immaterial amounts of NGLs (less than 0.6 mmbbls).

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

	2016		2017		**2018**	
	First Attributed	Total as at December 31, 2016	First Attributed	Total as at December 31, 2017	**First Attributed**	**Total as at December 31, 2018**
SCO (mmbbls)						
Mining	285	285		282	**26**	**308**
In Situ		1 118		1 167		**1 114**
Total SCO	285	1 403		1 449	**26**	**1 423**
Bitumen (mmbbls)						
Mining		577	25	581		
In Situ		347		275		**330**
Total Bitumen		924	25	856		**330**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada	7	79	33	104	**1**	**95**
Offshore U.K. & Norway	10	10	2	12	**8**	**9**
Total Light Crude & Medium Crude Oil	17	89	34	116	**9**	**104**
Heavy Crude Oil (mmbbls)						
E&P Canada		84		73		**28**
Offshore U.K. & Norway						
Total Heavy Crude Oil		84		73		**28**
Conventional Natural Gas (bcfe)						
E&P Canada						
Offshore U.K. & Norway[2]	3	3		3	**15**	**15**
Total Conventional Natural Gas	3	3		3	**15**	**15**
Total (mmboe)	303	2 500	59	2 494	**37**	**1 886**

(1) Figures may not add due to rounding.

(2) Includes immaterial amounts of NGLs (less than 0.7 mmbbls).

Generally, Proved Undeveloped and Proved Plus Probable Undeveloped reserves are attributed based on the associated confidence levels required for Proved and Proved Plus Probable reserves, respectively, arising from the consideration of factors such as regulatory approvals, availability of markets and infrastructure, development timing, and technical aspects, and have been assigned in accordance with COGE Handbook guidelines. Probable reserves are calculated as the difference between Proved and Proved Plus Probable reserves.

Undeveloped In Situ reserves, which constitute approximately 94% of Suncor's gross Proved Undeveloped reserves and 77% of Suncor's gross Probable Undeveloped reserves have been assigned to reserves areas which are not classified as Developed and are related only to those sustaining pads and well pairs required for current producing or sanctioned projects. 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, reserves have been drilled to a density of 16 delineation wells per section (i.e. 40 acre spacing), which is in excess of the eight delineation wells per section (80 acre spacing) required for regulatory approval. Further delineation is pursued through annual core hole drilling programs to refine development plans. Proved Undeveloped reserves have been assigned to areas delineated with vertical wells on 80 acre well spacing with 3D seismic control or 40 acre spacing without 3D seismic control, subject to being within 1.2 km from currently drilled or near-term planned production wells where approval is pending or within 2.4 km from producing wells. Probable Undeveloped areas are limited to areas delineated with vertical wells on 320 acre spacing with seismic control or 160 acre spacing without seismic control. Development of undeveloped In Situ reserves is an ongoing process and is a function of processing capacity and the forecasts of the declining production from existing In Situ wells. When production is forecast to decline, Suncor makes application for and, upon approval, commences development of the reserves and wells surrounding the declining areas. This entails drilling replacement well pairs and constructing sustaining pads and may take several years. Management uses integrated plans to forecast future Proved Undeveloped and Probable Undeveloped reserves development activity. These detailed plans align current production, processing and pipeline constraints (which, in the case of processing constraints, do not permit Suncor to develop all of its undeveloped In Situ reserves within two years), capital spending commitments and future development for the next 10 years, and are updated and approved annually for internal and external factors affecting planned activity. The economic viability of developing sustaining pads and associated well pairs is tested to ensure that ongoing development is economic as required for reserves assessment.

Undeveloped Mining reserves constitute approximately 16% of Suncor's gross Probable Undeveloped reserves, and relate to the Syncrude MLX-W mining area, which is well-delineated by core hole drilling. An application for regulatory approval has been submitted for the Syncrude MLX-W mining area. Development is anticipated to commence within one year of approvals being received.

Undeveloped conventional reserves (light crude oil and medium crude oil, heavy crude oil and natural gas) constitute approximately 6% of Suncor's gross Proved Undeveloped reserves and approximately 7% of Suncor's gross Probable Undeveloped reserves and relate to the company's offshore assets at E&P Canada, mainly associated with future drilling at Hebron, and under-drilled or undrilled fault blocks related to areas in Hibernia, White Rose and Terra Nova, and at the recently acquired Fenja development project offshore Norway. Attribution of Proved Undeveloped and Probable Undeveloped reserves reflect, where applicable, the respective degrees of certainty with respect to various reservoir parameters, primarily drainage areas and recovery factors. In developing undeveloped conventional reserves, Suncor considers existing facility capacity, capital allocation plans, and remaining reserves availability. Suncor plans to proceed with development of essentially all Proved Undeveloped reserves within the next three years and with the development of all Probable Undeveloped reserves within the next five years.

Properties with no Attributed Reserves

The following table is a summary of properties to which no reserves are attributed as at December 31, 2018. 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	4 331 614	3 239 642
Libya	3 117 800	1 422 900
Syria	345 194	345 194
Norway	254 491	109 936
U.K.	54 589	20 034
Australia (overriding royalty interest only)	113 027	
Total	**8 216 715**	**5 137 706**

Suncor's unproved properties include exploration properties in a 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 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, or, in the case of Libya and Syria, political unrest. 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. Refer to the Risk Factors section of this AIF for additional information on risks and uncertainties.

In 2019, Suncor's rights to 92,076 net hectares in Canada, 31,399 net hectares in Norway and nil net hectares in the U.K. are scheduled to expire. The expiries include approximately 48,000 net hectares in In Situ and 6,638 net hectares in Mining. Substantial portions of expiring lands may have their tenure continued beyond 2019 through the conduct of work programs and/or the payment of prescribed fees to the mineral rights owner.

Oil and Gas Properties and Wells

For descriptions of Suncor's important properties, plants, facilities and installations, refer to the Narrative Description of Suncor's Businesses section within this AIF.

The following table is a summary of the company's oil and gas wells as at December 31, 2018.

	Oil Wells(1)				Natural Gas Wells(1)			
	Producing		Non-Producing(2)(3)		Producing		Non-Producing(2)(3)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta In Situ(4)	369.0	369.0	56.0	56.0				
Newfoundland & Labrador(4)	76.0	18.9	9.0	2.8				
Offshore U.K. & Norway	43.0	12.4	7.0	2.1				
Other International(5)			419.0	211.1			6.0	6.0
Total	**488.0**	**400.3**	**491.0**	**272.0**			**6.0**	**6.0**

(1) Alberta oil wells and Other International oil and gas wells are onshore whereas Newfoundland & Labrador and Offshore U.K. & Norway wells are offshore.

(2) 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.

(3) Non-producing wells do not necessarily lead to classification of Non-Producing reserves.

(4) SAGD well pairs and multi-lateral wells are each counted as one well.

(5) Other International includes wells associated with the company's operations in Syria and Libya. There are no reserves associated with wells in Syria or Libya.

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, if any, are associated with SAGD well pairs that have typically been drilled within the last three years, yet 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.

Costs Incurred

The table below summarizes the company's costs incurred related to its oil and gas activities for the year ended December 31, 2018.

($ millions)	Exploration Costs	Proved Property Acquisition	Unproved Property Acquisition	Development Costs	Total

			Costs	Costs		
Canada	Mining and In Situ	73	1 143		3 398	4 614
Canada	E&P Canada	18			591	609
Total Canada		91	1 143		3 989	5 223
Offshore U.K. & Norway		153	82	32	209	476
Other International		8				8
Total		**252**	**1 225**	**32**	**4 198**	**5 707**

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, 2018.

	Exploratory Wells[1]		Development Wells	
Total number of wells completed	Gross	Net	Gross	Net
Canada — Oil Sands				
Oil			16.0	16.0
Service[2]	1.0	1.0	22.0	22.0
Stratigraphic Test[3]	46.0	43.8	490.0	351.7
Total	**47.0**	**44.8**	**528.0**	**389.7**
Canada — E&P Canada				
Oil			8.0	1.8
Dry Hole			1.0	0.4
Natural Gas				
Service[2]			3.0	0.6
Stratigraphic Test				
Total			**12.0**	**2.8**
Total Canada				
Oil			24.0	17.8
Dry Hole			1.0	0.4
Natural Gas				
Service[2]	1.0	1.0	25.0	22.6
Stratigraphic Test	46.0	43.8	490.0	351.7
Total	**47.0**	**44.8**	**540.0**	**392.5**
Offshore U.K. & Norway				
Oil			3.0	0.9
Dry Hole	1.0	0.3		
Service[2]			1.0	0.3

Stratigraphic Test				
Total	**1.0**	**0.3**	**4.0**	**1.2**

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

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

(3) Stratigraphic test wells for Oil Sands include core hole drilling wells.

Significant exploration and development activities in 2018 included:

- For Mining, at Oil Sands Base development activities included turnaround and major maintenance at Upgrader 1, construction of fluid management facilities and utilities sustainment. At Fort Hills, development activities focused on completion of the remaining construction activities in secondary extraction. Other development activities for Fort Hills included procuring mobile equipment and advancing tailings infrastructure. At Syncrude, development activities included turnaround and reliability projects.

- 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 as well as provide future growth. Also included are stratigraphic test well drilling programs.

- For E&P Canada, drilling activities at Hebron, development drilling for White Rose, Hibernia and Terra Nova, as well as development work on the WWRP.

- For E&P International, development drilling for GEAD, as well as development work on Buzzard and the Norwegian Oda and Fenja projects.

For significant exploration and development activities expected to occur in 2019 and beyond, refer to the Narrative Description of Suncor's Businesses and Additional Information Relating to Reserves Data Future Development Costs sections in this AIF.

Production History[1]

2018	Q1	Q2	Q3	Q4	Year Ended
Canada Oil Sands					
Total production (mmbls/d)	**571.7**	**547.6**	**651.7**	**740.8**	**628.6**
Oil Sands operations Bitumen (mmbls/d)	**125.4**	**121.0**	**146.0**	**159.3**	**138.0**
($/bbl)					
Average price realized[2]	27.57	42.84	36.62	2.43	24.70
Royalties	(0.90)	(3.27)	(3.20)	(0.06)	(1.70)
Production costs	(8.75)	(7.37)	(7.01)	(7.61)	(7.68)
Netback[4]	17.92	32.20	26.41	(5.24)	15.32
Oil Sands operations SCO and diesel (mbbls/d)	**279.4**	**237.9**	**330.1**	**273.4**	**280.3**
($/bbl)					
Average price realized[2]	70.51	80.00	82.95	42.44	68.97
Royalties	(0.56)	(2.60)	(2.70)	(0.91)	(1.63)
Production costs	(31.38)	(35.65)	(25.52)	(30.21)	(30.36)
Netback[4]	38.57	41.75	54.73	11.32	36.98
Fort Hills Bitumen (mbbls/d)	**24.6**	**70.9**	**69.4**	**98.5**	**66.1**
($/bbl)					
Average price realized[2]	32.48	51.86	53.43	20.26	38.47
Royalties	(1.54)	(0.73)	(3.07)	(1.41)	(1.67)
Production costs	(106.07)	(22.73)	(30.69)	(28.79)	(30.32)
Netback[4]	(75.13)	28.40	19.67	(9.94)	6.48
Syncrude SCO (mbbls/d)	**142.3**	**117.8**	**106.2**	**209.6**	**144.2**

($/bbl)					
Average price realized[2]	76.85	86.16	88.80	47.71	70.19
Royalties	(1.57)	(2.41)	(2.49)	(1.53)	(1.90)
Production costs	(45.30)	(52.27)	(62.61)	(28.33)	(43.81)
Netback[4]	29.98	31.48	23.70	17.85	24.48

Canada Light Crude & Medium Crude Oil

Total production (mbbls/d)	**58.5**	**58.6**	**48.9**	**47.9**	**53.4**

($/bbl)					
Average price realized[2]	82.79	95.06	97.22	73.48	87.82
Royalties	(14.34)	(13.02)	(18.75)	(5.04)	(13.31)
Production costs	(9.70)	(11.21)	(16.06)	(23.71)	(14.43)
Netback[4]	58.75	70.83	62.41	44.73	60.08

Offshore U.K. & Norway Light Crude & Medium Crude Oil[3]

Total production (mboe/d)	**54.7**	**52.0**	**41.6**	**38.4**	**46.6**

($/boe)					
Average price realized[2]	81.08	91.68	92.06	83.17	86.92
Royalties					
Production costs	(5.36)	(5.39)	(6.04)	(8.94)	(6.27)
Netback[4]	75.72	86.29	86.02	74.23	80.65

(1) Production and liftings in Libya were intermittent in 2018 and not material to Suncor, and therefore are not included.

(2) Average price realized is net of transportation costs, and before royalties.

(3)

Volumes include field production for immaterial amounts of associated gas and NGLs.

(4) Netback is a non-GAAP financial measure. See the Advisory Forward-Looking Information and Non-GAAP Financial Measures section of this AIF.

The following table provides the production volumes[(1)] on a working-interest basis, before royalties for each of Suncor's important fields for the year ended December 31, 2018.

		SCO	Bitumen	Light & Medium Oil
		mbbls/d	mbbls/d	mboe/d
Mining	Suncor	201.1		
Mining	Syncrude	144.2		
Mining	Fort Hills		66.1	
Firebag		79.2	102.0	
MacKay River			36.0	
Buzzard				34.2
GEAD				12.4
Hibernia				22.1
White Rose				6.6
Terra Nova				11.7
Hebron				13.0
Total		**424.5**	**204.1**	**100.0**

(1) Volumes shown are actual volumes and may differ from the estimated volumes shown in the Reconciliation of Gross Reserves Table.

Production Estimates

The table below outlines the production estimates for 2019 that are included in the estimates of Proved reserves and Probable reserves as at December 31, 2018.

	SCO (mbbls/d)[(1)]		Bitumen (mbbls/d)[(1)(2)]		Light & Medium Crude Oil (mbbls/d)[(1)]		Conventional Natural Gas (mmcfe/d)[(1)(3)]		Total (mboe/d)[(1)]	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
Proved	445	430	212	203	49	39			707	672
Probable	33	32	(14)	(15)	11	10			29	27

Proved Plus Probable	478	462	198	188	60	49			736	699
Offshore U.K. & Norway										
Proved					35	35	3	3	36	36
Probable					13	13	4	4	14	14
Proved Plus Probable					48	48	7	7	49	49
Total[(1)(5)]										
Proved	445	430	212	203	84	74	3	3	742	708
Probable	33	32	(14)	(15)	24	23	4	4	43	41
Proved Plus Probable	478	462	198	188	108	97	7	7	785	749

(1) Figures may not add due to rounding.

(2) Negative estimated Bitumen production in the Probable reserves class is a result of the methodology used to estimate Probable reserves and the methodology by which the Government of Alberta's mandated production curtailments were incorporated into the Proved Plus Probable and Proved reserves cases, respectively.

(3) Conventional Natural Gas includes immaterial amounts of NGLs.

The following properties each account for approximately 20% or more of total estimated production for 2019.

Proved

- From Millennium and North Steepbank: 223 mbbls/d of SCO, which represents approximately 30% of total estimated production for 2019.
- From Firebag: 178 mbbls/d of SCO and bitumen (79 mbbls/d and 99 mbbls/d, respectively), which represents approximately 24% of total estimated production for 2019.
- From Syncrude 142 mbbls/d of SCO, which represents approximately 19% of total estimated production for 2019.

Proved Plus Probable

- From Millennium and North Steepbank: 236 mbbls/d of SCO, which represents approximately 30% of total estimated production for 2019.
- From Firebag: 161 mbbls/d of SCO and bitumen (83 mbbls/d and 78 mbbls/d, respectively), which represents approximately 21% of total estimated production for 2019.
- From Syncrude: 158 mbbls/d of SCO from Syncrude, which represents approximately 20% of total estimated production for 2019.

None of the company's Light & Medium Crude Oil production associated with its E&P Canada and Offshore U.K. & Norway assets account for 20% or more of the total estimated production for 2019.

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 to which it holds rights as at December 31, 2018. These commitments run through 2021 and beyond, and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area ($ millions)	2019	2020	2021+	Total
Canada				
Other International			490	490

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 2018. A description of Suncor's use of such instruments is provided in the 2018 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2018.

Tax Horizon

In 2018, Suncor was subject to cash tax in the majority of the jurisdictions in which it generates earnings, including earnings related to its Canadian, Offshore U.K. & Norway and Other International production. Based on projected future net earnings, Suncor is expected to be cash taxable on the majority of its earnings in 2019.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations. These regulations are imposed by legislation enacted by various levels of government and, with respect to the export and taxation of oil and natural gas, by agreements among the governments of Canada, Ontario, Quebec, Alberta, British Columbia, and Newfoundland and Labrador, as well as the governments of the United States and other foreign jurisdictions in which Suncor operates, all of which should be carefully considered by investors in the oil and gas industry. Current legislation is a matter of public record. All governments have the ability to change legislation, and the company is unable to predict what additional legislation or amendments to legislation may be enacted. Suncor may engage in government consultation regarding proposed legislative changes to ensure Suncor's interests are recognized. The following discussion outlines some of the principal legislation, regulations and agreements that govern 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 and medium crude oil or exceeds two years for oil other than heavy crude oil (in either case, 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 oil other than heavy crude oil or does not exceed two years for heavy crude oil, the exporter is required to obtain an order from the NEB approving such export.

In February 2018, the federal government issued Bill C-69, *an Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts* (Bill C-69), which, among other things, proposes changes to the NEB regime. The changes proposed in Bill C-69, if and when adopted into law, do not materially alter the current requirements around oil exports. However, at this stage, it is not certain whether or when the federal government might issue new or revised regulations that might impact the oil export regime currently in place.

Under the North American Free Trade Agreement (NAFTA), Canada is free to determine whether exports of energy resources to the United States or Mexico will be allowed, subject to certain conditions, and 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.

In November 2018, Canada, the U.S. and Mexico signed the *Canada-United States-Mexico Agreement* (CUSMA) with a view to replacing NAFTA. Under CUSMA, Canada will no longer be subject to the proportionality provisions in NAFTA's energy chapter, which should permit the expansion of oil and gas exports beyond the U.S. In addition, CUSMA includes a change to the oil and gas rules of origin which will allow Canadian exporters to more easily qualify for duty-free treatment for shipments to the U.S. Canada must, however, notify the U.S. of its intention to enter free trade talks with any "non-market economies" under CUSMA, which may include China or other potential importers of Canadian oil and gas exports. Legislators from each of the three countries must ratify CUSMA according to their own legislative processes before it goes into effect and replaces NAFTA. The outcome of the ratification process in each of these countries is not complete and is therefore uncertain; however, it is currently anticipated that CUSMA will come into force on January 1, 2020.

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 and other large oil and natural gas producing countries, 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. Crown royalties are determined by governmental regulation or by agreement with governments 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 for 2018 was 15% for active business income, including resource income. The average provincial income tax rate for Suncor in 2018 was 12.04%.

On November 21, 2018, the Canadian federal government released its *Fall Economic Statement 2018* (the Statement). The Statement included the announcement of significant changes to the Canadian tax depreciation rates for capital assets. The new tax depreciation rates were not substantively enacted prior to December 31, 2018, and apply only for capital expenditures incurred and available for use after November 20, 2018. The new tax depreciation rates will begin to phase out in 2024 with full phase out by the end of 2027. These changes are expected to reduce Suncor's cash tax obligations in 2019.

Other Jurisdictions

Operations in the U.S. are subject to the U.S. federal tax rate of 21% and the effective rate for state taxes is approximately 2.5%, resulting in a total U.S. income tax rate of approximately 23.5%.

Operations in the U.K. are subject to a tax rate of 40%, made up of the corporate income tax rate and the supplemental charge. In Norway, operations are subject to a tax rate of 78%.

Amounts presented in Suncor's 2018 audited Consolidated Financial Statements as royalties for production from the company's 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.

Land Tenure

In Canada, crude oil and natural gas located in the western provinces are predominantly owned 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 the western provinces may also be privately owned, and rights to explore for and produce such oil and natural gas resources are granted pursuant to a private lease on the terms and conditions negotiated with the mineral rights holder. In central and eastern provinces and offshore 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 or territorial 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. Among other things, these environmental regulatory regimes impose restrictions and prohibitions on the spill, release or emission of various substances including oil and gas and the byproducts associated with the production thereof, which apply to Suncor and all other companies in the energy industry. Applicable 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, as well as the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are generally required before most new major projects or significant changes to existing operations can be initiated. In addition, these environmental regulatory regimes require the company to abandon and reclaim mine, well and facility sites to the satisfaction of regulatory authorities. In some cases, abandonment and reclamation obligations 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/or the imposition of material fines and penalties.

In addition to the specific requirements outlined above, Suncor anticipates that future amendments to environmental laws will result in the imposition of additional requirements on companies operating in the energy industry.

A number of statutes, regulations and governance frameworks pertaining to environmental regulation are currently under development and, in some cases, proposed amendments have been issued by the provincial regulators that oversee oil sands development for comment by industry. These statutes, regulations and frameworks relate to issues such as tailings management, water use, biodiversity, air emissions and land use. 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, the impact of current and future environmental laws and regulations on the company's business and operations, including laws and regulations relating to climate change, remains uncertain. It is not possible to predict the nature of any future legislative requirements, including those currently set out in Bill C-69, or the impact the future requirements will have on the company and its business, financial condition and results of operations. Suncor continues to actively work to mitigate the company's environmental impact, including taking action to reduce GHG emissions intensity, installing new emissions abatement equipment, investing in renewable forms of energy, such as wind power and biofuels, undertaking land reclamation activities, investing in environmentally focused research and development, and working to advance other environmental technologies. Refer to the Narrative Description of Suncor's Businesses Oil Sands New Technology section of this AIF.

Recent developments in environmental regulation and related government initiatives have 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 regulate, or have proposed to regulate, industrial GHG emissions. Suncor is committed to fully complying with existing regulations and will continue to constructively engage the appropriate governmental bodies in meaningful dialogue to harmonize regulations focused on achieving actual reduction goals and sustainable resource development across jurisdictions within North America.

As part of its ongoing business planning, Suncor estimates future costs associated with CO_2 emissions in its operations and the evaluation of future projects, based on the company's outlook for the carbon price under current and pending GHG regulations, using a price of $30/tonne of CO_{2e} steadily increasing to approximately $100/tonne of CO_{2e} in 2040 as a base case, applied against a range of policy design options. The company expects that GHG emissions regulation will continue to evolve with a carbon price signal that balances economic, environmental and energy security objectives. Suncor will continue to review the impact of future carbon-constrained scenarios on its business strategy.

Some of the recent environmental regulations and initiatives related to climate change and GHG emissions are described below.

International Climate Change Agreements

The goals of the Paris Agreement on climate change, an agreement within the United Nations Framework Convention on Climate Change that came into force on November 4, 2016, are to prevent the global temperature rise from exceeding 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius above pre-industrial levels. Pursuant to the Paris Agreement, the Government of Canada set a goal to reduce GHG emissions economy-wide by 30% below 2005 levels by 2030.

Canadian Federal GHG Regulations

In furtherance of its commitments under the Paris Agreement, the federal government developed the *Pan-Canadian Framework on Clean Growth and Climate Change* (PCF) in 2016 to meet Canada's emissions target while enabling economic growth.

Under the PCF, the federal government requires all provinces and territories to have a carbon price, starting at $20 per tonne in 2019 and rising by $10 per year to $50 per tonne in 2022. Jurisdictions can implement: (i) an explicit price-based system (such as the carbon tax adopted by British Columbia or the carbon levy and performance-based emissions system adopted in Alberta), or (ii) a cap-and-trade system (which has been adopted in Quebec). Within these programs, provinces have discretion to manage competitiveness of their trade-exposed industries. The carbon pricing initiatives adopted in British Columbia, Alberta, Quebec, and Newfoundland and Labrador and their impact on Suncor are described in the Canadian Provincial GHG Regulations section below.

The 2018 federal *Greenhouse Gas Pollution Pricing Act* (GGPPA) establishes the federal carbon price on GHG emissions applicable as of January 2019. The GGPPA reinforces the approach taken in the PCF and is only intended to serve as a regulatory carbon pricing "backstop", to any province or territory that requests it, or to those jurisdictions that have not otherwise implemented a compliant provincial or territorial carbon pricing regime. The GGPPA consists of two parts: (1) a levy on fossil fuels; and (2) an output-based pricing system.

In addition to the carbon pricing "backstop", a Clean Fuel Standard with the objective of achieving annual reductions of 30 Mt of GHG emissions by 2030 is being developed by the federal government. If implemented, the standard would require reductions in the carbon intensity of the fuels supplied in Canada, based on a new life cycle analysis model to be developed by the federal government. The approach is not expected to differentiate between crude oil types produced in or imported into Canada. This standard is expected to apply to a broad suite of fuels used in transportation, industry, homes and buildings; however, as the standard is currently under development with proposed regulations to implement the standard not anticipated to be enacted until mid-2019, the company is unable to predict the impact, if any, the yet to be finalized Clean Fuel Standard will have on its business at this time.

Canadian Provincial GHG Regulations

In 2007, the Government of Alberta enacted the *Specified Gas Emitters Regulation* (SGER), which applied to facilities in Alberta with CO_{2e} emissions in excess of 100,000 tonnes per year. Suncor's Oil Sands Base plant, MacKay River plant, Firebag operations, the Edmonton refinery and Syncrude were subject to the SGER up until December 31, 2017. For the 2017 compliance year, Suncor's compliance cost under the SGER was $24 million in respect of its owned and operated properties. Suncor also earned compliance credits under the SGER valued at $12 million based on the 2017 carbon price of $30/tonne. Fort Hills was deemed to be a "new facility" and was exempt from compliance payments under SGER in 2017. The 2017 compliance cost for Syncrude was $31 million, net to Suncor.

On January 1, 2018, the SGER was replaced with the *Carbon Competitiveness Incentive Regulation* (CCIR), with a three-year phase-in period. Similar to the SGER, the CCIR applies to facilities with CO_{2e} emissions in excess of 100,000 tonnes per annum. The CCIR is designed to incent regulated facilities to reduce GHG emissions through improving performance by establishing product-based performance standards (also called output-based allocations) across all industries. To protect the competitiveness of trade-exposed sectors like the oil sands, the CCIR provides facilities with output-based allocation credits up to a predetermined performance benchmark. Performance benchmarks have been set for each of oil sands mining, in situ, upgrading, refining and electricity generation operations. Facilities will pay a carbon levy based on the amount of net emissions by which they fall short of the performance benchmark and companies will receive credits based on the amount of reductions by which they exceed the benchmark. The 2018 carbon levy remained flat at $30/tonne of CO_{2e}. For 2018, the estimated compliance cost for all of Suncor's owned and operated Alberta assets is $46 million. Fort Hills will remain exempt as a "new facility" under the CCIR until the end of 2019. The 2018 estimated compliance cost for Syncrude was $36 million, net to Suncor.

For 2019, the carbon levy in Alberta will remain at $30/tonne of CO_{2e}. The 2019 estimated compliance cost for all of Suncor's owned and operated Alberta assets is $88 million. The 2019 estimated compliance cost for Syncrude is $37 million, net to Suncor. The change year-over-year in compliance costs is due to higher than forecast output-based allocation benchmarks published for oil sands mining, in situ and upgrading.

Effective as of January 1, 2017, Alberta enacted the *Climate Leadership Implementation Act* (Climate Act). The Climate Act implements an economy-wide carbon levy on GHG emissions resulting from the combustion of fuels for heating and transportation on consumers and larger facilities on operations not otherwise subject to the CCIR.

Further, the Alberta *Oil Sands Emissions Limit Act* (the OSELA) sets a limit of 100 Mt of CO_{2e} per year in the oil sands sector, excluding emissions from cogeneration and new upgrading capacity, allowing for continued growth and development while the sector works to accelerate emissions reduction technologies and operational optimization. Current oil sands emissions are estimated to be 70 Mt/year, including existing upgrading capacity, but excluding cogenerated electricity sold to the Alberta power grid. The mechanics of implementation and enforcement of the OSELA remain under review by the Government of Alberta and it is not yet possible to predict the long-term impact on opportunities for Suncor.

The Province of British Columbia enacted a carbon tax in 2008. The tax increased in 2018 to $35/tonne of CO_{2e} and is set to rise annually by $5/tonne until it reaches $50/tonne of CO_{2e} in 2021. The carbon tax is applied on consumption. The purchaser or user of fuels pays the carbon tax, which is collected by Suncor and forwarded on to the government.

Implemented in 2013, Quebec's Cap and Trade System for Greenhouse Gas Emissions Allowances applies to companies in the industrial and electricity sectors that emit 25,000 Mt of CO_{2e} per year or greater. Quebec's cap-and-trade system is linked to the Western Climate Initiative (WCI), an organization set up to help member states and provinces execute their cap-and-trade systems. Allowances and offsets are fungible across the WCI. In Quebec, emitters are required to either reduce their emissions or purchase eligible compliance mechanisms to cover their emissions above a specified cap. The cap and the allocation of free allowances are established by the Province. Suncor's Montreal refinery and associated transportation emissions are subject to Quebec's cap-and-trade system. For the 2017 and 2018 compliance years, the cost of compliance for the Montreal refinery was $1.9 million and $1.2 million, respectively. The 2019 forecast compliance cost attributed to the Montreal refinery's stationary emissions is $1.9 million. The majority of the compliance costs covering the emissions from transportation fuels are passed through to the customer.

Effective January 1, 2018, Ontario formally launched its cap-and-trade system under WCI. Due to a change in government, the program was cancelled effective July 3, 2018. This was followed by the passage of Bill 4, *Cap and*

Trade Cancellation Act effective October 31, 2018. Facilities, including Suncor's Sarnia refinery, that generate more than 25,000 tonnes of GHG emissions per year were required to participate in the cap-and-trade program until the time of cancellation. For the 2018 compliance year, the cost of compliance for the Sarnia refinery was $3.1 million. Similar to Quebec, costs attributed to emissions from transportation fuels are passed through to the customer.

The Government of Newfoundland and Labrador's carbon pricing plan will take effect on January 1, 2019 with a carbon price of $20 per tonne of CO_{2e}. The plan is a hybrid system comprised of performance standards for large industrial facilities, including large-scale electricity generation, plus a consumer carbon tax on transportation, building fuels, electricity generation and other fuels combusted in the province. Performance standards for large industrial facilities are legislated under the *Management of Greenhouse Gas Act* (MGGA) and associated regulations, which apply to all facilities that emit 15,000 tonnes of CO_{2e} or more per annum. The MGGA also contemplates the establishment of a fund for clean technology through compliance payments made by industrial emitters. This is expected to support technology and innovation as well as provide flexible compliance options and protect the competitiveness of energy-intensive trade-exposed sectors such as the province's offshore petroleum sector. Large industrial emitters, which include the offshore petroleum sector, account for approximately 43% of the province's current emissions. For 2019, onshore facilities will be assigned an annual GHG reduction target equal to 6% below the facility's 2016 to 2017 historical average emissions to output ratio. The target will rise by 2% per year until the reduction target reaches 12% in 2022. To protect the competitiveness of offshore petroleum facilities, each regulated facility will be assigned the same percentage reductions to its average emissions level, excluding federally regulated emissions for methane from venting and fugitive emissions. Consistent with the government's Advance 2030 initiative to encourage oil and gas development in the province, mobile offshore drilling unit activities related to exploration will not be subject to the carbon levy. The 2019 estimated compliance cost attributed to the company's E&P Canada assets is $14.2 million, including Suncor's net share of non-operated properties.

U.S. GHG Regulations

The U.S. Environmental Protection Agency (U.S. EPA) has established a rule mandating that all large facilities (defined as facilities emitting greater than 25,000 tonnes of CO_{2e} per year, which includes Suncor's refinery in Commerce City, Colorado) must report their GHG emissions. The mandate of the U.S. EPA is under review by the current administration. In June 2017, the withdrawal of the U.S. from the Paris Agreement was announced. The current administration has also overturned a number of decisions made by the previous administration. Efforts have also been made at the state level to adopt legislation requiring entities to report on GHG emissions. Suncor continues to monitor these developments. The outcome of these changes in approach to GHG emissions is currently unclear and the impact on Suncor, including its Commerce City, Colorado refinery, is unknown at this time.

International Regulations

The European Union Emissions Trading Scheme (EU ETS) applies to Suncor's non-operated offshore U.K. and offshore Norway assets. The EU ETS requires that member countries set emissions limits for installations in their country covered by the scheme and assigns such installations an emissions cap. Installations may meet their cap by reducing emissions or by buying allowances from other participants. Phase III of EU ETS includes a transition from free allocation to auctioning allowances.

Land Use

In 2012, the Government of Alberta approved the Lower Athabasca Regional Plan (LARP). The LARP addresses land-use management in the Lower Athabasca region of Alberta, which includes the area of the province in which Suncor's Oil Sands business is located. The LARP, which was developed pursuant to the *Alberta Land Stewardship Act*, is part of Alberta's approach to managing land and natural resources to achieve long-term economic, environmental and social goals, and identifies new conservation areas as well as management frameworks to ensure the continued regional quality of air, surface water and groundwater. The conservation areas established by LARP do not overlap with any of Suncor's or Syncrude's leases.

The management frameworks established under LARP formalize a number of regulatory tools used by the government to manage environmental aspects of oil sands development, including cumulative environmental effects management on a regional scale. As a result, LARP may require Suncor and Syncrude to have greater participation in the overall evaluation of environmental issues and emissions in the Lower Athabasca region. The frameworks established under LARP include the following:

Air Quality Management Framework (AQMF). The AQMF is designed to maintain flexibility and to manage the cumulative effects of development on air quality within the Lower Athabasca region, setting triggers and limits for nitrogen dioxide (NO_2) and sulphur dioxide (SO_2). The AQMF includes ambient air quality triggers and limits. Regulatory actions will occur when triggers or limits are reached or exceeded.

Surface Water Quality Management Framework (SWMF-Quality). The SWMF-Quality provides a basis with which to monitor and manage long-term, cumulative changes in water quality within the Lower Athabasca River. The SWMF-Quality 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.

Surface Water Quantity Management Framework (SWMF-Quantity). The SWMF-Quantity establishes weekly management triggers and water withdrawal limits that enable proactive management of mineable oil sands water used from the Athabasca River. Weekly water withdrawal limits reflect seasonal variability and may become more restrictive as flows in the river change. Suncor and Syncrude have voluntarily agreed to minimize water withdrawals for pre-existing plant operations to no more than their annual withdrawal licence average of 2 m^3/s, during periods of low flow for the Athabasca River. The Fort Hills mining project has on-site water storage to meet the SWMF-Quantity requirements during low flow. To ensure that weekly flow triggers and cumulative water use limits for oil sands mining operators are met, each oil sands mining operator enters into an annual Oil Sands Water Management Sharing Agreement which is submitted to Fisheries and Oceans Canada and Alberta Environment and Parks. The agreement reduces the cumulative amount of water being withdrawn by oil sands mining operations when necessary to ensure that the cumulative water use limits established under SWQMF-Quantity are met.

Groundwater Management Framework (GMF). The GMF aims to manage non-saline groundwater resources in a sustainable manner and protect groundwater resources from contamination and over use. It 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.

Tailings Management Framework for Mineable Athabasca Oil Sands (TMF). The TMF provides oil sands mining operations with direction regarding the management of fluid tailings volumes during and after mine operation in order to manage and mitigate liability and environmental risk resulting from the accumulation of fluid tailings on the landscape. 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. As a part of the implementation of the TMF, the AER released the Tailings Directive in October 2017. The Tailings Directive uses fluid tailings volume triggers and a limit, as well as management actions such as a compliance levy and financial bonds through the Mine Financial Security Program (MFSP), to support the overarching policy objective of minimizing fluid tailings accumulation while balancing environmental, social and economic needs. The amount of any financial management actions, including compliance levies, and financial bonds through the MFSP have yet to be set. As such, it is not possible to predict what impact financial management actions imposed pursuant to the Tailings Directive could have on Suncor at this time.

Suncor is committed to reclaiming and remediating lands affected by its operations. In the past few years, Suncor has improved its tailings management efforts and became the first company to reclaim an oil sands tailings pond, convert a second to a fluid tailings treatment area, and make another pond trafficable with coke capping. Under the TMF, updated tailings management plans are required to be submitted for Oil Sands Base, Syncrude Mildred Lake, Syncrude Aurora North and Fort Hills. The updated tailings management plans for Oil Sands Base, Syncrude Aurora North and Fort Hills were approved in October 2017, June 2018 and February 2019, respectively, and the updated tailings management plan for Syncrude Mildred Lake is pending approval by the AER.

Another important component identified in the TMF is a need to focus on integrated water management as Suncor and Syncrude reclaim and liberate water from tailings. By fully considering all water management options (reduce, reuse, recycle and return) and existing policy and regulatory mechanisms, work is being completed to consider and develop any additional criteria, guidelines, policy and/or regulatory work required to support all aspects of an integrated approach involving successful reclamation and closure planning.

Reclamation

The Government of Alberta's MFSP accounts for the environmental liability associated with the suspension, abandonment, remediation and surface reclamation of oil sands mines and plant sites. The MFSP requires a base amount of security for each project. Suncor has provided this security in the form of letters of credit and 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 to date. 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 provides early warning of any potential risks of a tailings management action specific to the TMF. It is expected that revisions to the MFSP will be completed in the 2019 to 2020 time frame.

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 cost to the oil sands industry of enhanced monitoring under the Monitoring Plan have been estimated at approximately $50 million per year. The 2018 annual cost to Suncor under the Monitoring Plan is estimated to be approximately $13 million, including Suncor's net share of Syncrude compliance costs.

Industry Collaboration Initiatives

Environmentally focused collaboration between companies and stakeholders is an important focus for the oil sands industry. Suncor is a founding member of Canada's Oil Sands Innovation Alliance (COSIA) and is committed to collaborative action to accelerate improvements in environmental performance, including tailings, water, land, monitoring 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 and assessment 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 realization of any of the following risks could have a material adverse effect on Suncor's business, financial condition, reserves or results of operations.

Volatility of Commodity Prices

Suncor's financial performance is closely linked to prices for crude oil in the company's upstream business and prices for refined petroleum products in the company's downstream business and, to a lesser extent, to natural gas prices in the company's 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 the company's 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), market access constraints, regional and international supply and demand imbalances, political developments and government action (including the mandatory production curtailments recently imposed by the Government of Alberta), decisions by OPEC to not impose quotas on its members, compliance or non-compliance with quotas agreed upon by OPEC members and other countries, 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 oil and SCO.

Refined petroleum product 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, market access, marketplace competitiveness, and other local market factors. Natural gas prices in North America are affected by, among other things, supply and demand, and by prices for alternative energy sources. Decreases in product margins or increases in natural gas prices could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

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 in part 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. Suncor's production from Oil Sands includes significant quantities of bitumen and SCO that may trade at a discount to light and medium crude oil. Bitumen and SCO are typically more expensive to produce and process. In addition, the market prices for these products may differ from the established market indices for light and medium grades of crude oil. As a result, the price received for bitumen and SCO may differ from the benchmark they are priced against. Future quality differentials are uncertain and unfavourable differentials could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

In the fourth quarter of 2018, there was insufficient market access capacity to remove production from the Western Canada Sedimentary Basin causing the differential between WTI and WCS to widen significantly. The situation triggered a response from the Government of Alberta in the form of a mandatory production curtailment, which commenced in early 2019. Such circumstances may result in worsening and/or prolonged price volatility and/or further negative impacts on market dynamics that cannot currently be fully anticipated. Wide differentials, such as those experienced in the fourth quarter of 2018 or a prolonged period of low and/or volatile commodity prices, particularly for crude oil, could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations, and may also lead to the impairment of assets, or to the cancellation or deferral of Suncor's growth projects.

Market Access

Suncor's production of bitumen is expected to grow. The markets for bitumen blends or heavy crude oil are more limited than those for light crude oil, making them more susceptible to supply and demand changes and imbalances (whether as a result of the availability, proximity, and capacity of pipeline facilities, railcars, 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.

Market access for Suncor's oil sands production may be constrained by insufficient pipeline takeaway capacity, including the lack of new pipelines due to an inability to secure required approvals and negative public perception. There is a risk that constrained market access for oil sands production, growing inland production and refinery outages could create widening differentials that could impact the profitability of product sales. Market access for refined products may also be constrained by insufficient takeaway capacity, which could create a supply/demand imbalance. The occurrence of any of the foregoing could have a material adverse effect on the company's business, financial condition, reserves and results of operations.

Major Operational Incidents (Safety, Environmental and Reliability)

Each of Suncor's primary operating businesses Oil Sands, E&P, and Refining and Marketing requires significant levels of investment in the design, operation and maintenance and decommissioning of facilities, and carries the additional economic risk associated with operating reliably or enduring a protracted operational outage. The breadth and level of integration of Suncor's operations adds complexity.

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, delays in resuming normal operations, fines, civil suits or criminal charges against the company.

In general, Suncor's operations are subject to operational hazards and risks such as, among others, fires (including forest fires), explosions, blow-outs, power outages, severe winter climate conditions, prolonged periods of extreme cold or extreme heat, flooding, droughts and other extreme weather conditions, railcar incidents or derailments, the migration of harmful substances such as oil spills, gaseous leaks or a release of tailings into water systems, pollution and other environmental risks, and accidents, 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, among other things, failure to follow the company's policies, standards and 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, network or cyber 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, including, among others, the following:

- Suncor's Oil Sands business is susceptible to loss of production, slowdowns, shutdowns or restrictions on its ability to produce higher value products, due to the failure of any one or more interdependent component systems, and other risks inherent to oil sands operations;

- For Suncor's E&P 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, or the presence of hydrogen sulphide), premature declines of reservoirs, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids and other accidents;

- 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 drilli