UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

(Check One)

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

or

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

For fiscal year ended: December 31, 2022
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:	Trading Symbol(s):	Name of each exchange on which registered:
Common shares	**SU**	**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:

☒ Annual Information Form ☒ 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, 2022 there were 1,337,470,739 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☒ No☐

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☒ No☐

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 ☐

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.

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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 March 6, 2023, Audited Consolidated Financial Statements, Management's Discussion and Analysis for the year ended December 31, 2022 and Supplementary Oil and Gas Disclosures, included as Exhibit 99-1, Exhibit 99-2, Exhibit 99-3 and Exhibit 99-10, 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- 265216).

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

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

B. Consent to Service of Process

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

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

See pages 2 and 3 of Exhibit 99-2 and page 70 of Exhibit 99-3.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See pages 4, 5,6 and 7 of Exhibit 99-2.

AUDIT COMMITTEE FINANCIAL EXPERT

See page 95 of Exhibit 99-1.

CODE OF ETHICS

See pages 35 and 36 of Exhibit 99-1.

FEES PAID TO PRINCIPAL ACCOUNTANT

See page 95 of Exhibit 99-1.

AUDIT COMMITTEE PRE-APPROVAL POLICIES

See Schedule "B" of Exhibit 99-1.

APPROVAL OF NON-AUDIT SERVICES

See Schedule "B" of Exhibit 99-1.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 94 of Exhibit 99-1.

EXHIBIT INDEX

Exhibit No.	Description
99-1	Annual Information Form dated March 6, 2023
99-2	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2022
99-3	Management's Discussion and Analysis dated March 6, 2023
99-4	Consent of KPMG LLP
99-5	Consent of GLJ Ltd.
99-6	Certificate of the Chief Executive Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-7	Certificate of the Chief Financial Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-8	Certificate of the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99-9	Certificate of the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99-10	Supplementary Oil and Gas Disclosures
101	Inline interactive data file
104	Cover page interactive data file (formatted as Inline XBRL and contained in Exhibit 101)

SIGNATURES

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

DATE: March 6, 2023

SUNCOR ENERGY INC.

PER: /s/ ALISTER COWAN
Alister Cowan
Chief Financial Officer

EXHIBIT 99-1

Annual Information Form dated March 6, 2023

Table of Contents

2	Advisories
3	Glossary of Terms and Abbreviations
3	Common Industry Terms
6	Common Abbreviations
7	Conversion Table
8	Corporate Structure
8	Name, Address and Incorporation
8	Intercorporate Relationships
10	General Development of the Business
10	Overview
12	Three-Year History
17	Narrative Description of Suncor's Businesses
17	Oil Sands
23	Exploration and Production
29	Refining and Marketing
33	Other Suncor Businesses
35	Suncor Employees
35	Ethics, Social and Environmental Policies
37	Statement of Reserves Data and Other Oil and Gas Information
40	Oil and Gas Reserves Tables and Notes
46	Future Net Revenues Tables and Notes
53	Additional Information Relating to Reserves Data
64	Industry Conditions
81	Risk Factors
82	Dividends
83	Description of Capital Structure
85	Market for Securities
86	Directors and Executive Officers
94	Audit Committee Information
97	Legal Proceedings and Regulatory Actions
97	Interests of Management and Others in Material Transactions
97	Transfer Agent and Registrar
97	Material Contracts
97	Interests of Experts
97	Disclosure Pursuant to the Requirements of the NYSE
98	Additional Information
99	Advisory – Forward-Looking Information and Non-GAAP Financial Measures
	Schedules
A-1	SCHEDULE "A" – AUDIT COMMITTEE MANDATE
B-1	SCHEDULE "B" – SUNCOR ENERGY INC. POLICY AND PROCEDURES FOR PRE-APPROVAL OF AUDIT AND NON-AUDIT SERVICES
C-1	SCHEDULE "C" – FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

D-1 SCHEDULE “D” – FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

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 29 of the company’s 2022 audited Consolidated Financial Statements), unless the context otherwise requires. Suncor Energy Inc. has numerous direct and indirect subsidiaries, partnerships and joint arrangements (affiliates), that own and operate assets and conduct activities in different jurisdictions. The terms “Suncor” or “the company” in this AIF are used herein for simplicity of communication and only mean that there is an affiliation with Suncor Energy Inc., without necessarily identifying the specific nature of the affiliation. The use of such terms in any statement herein does not mean that they apply to Suncor Energy Inc. or any particular affiliate, and does not waive the corporate separateness of any affiliate. For further clarity, Suncor Energy Inc. does not directly operate or own assets in the U.S. 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. Libyan production volumes are presented on an economic basis.

References to the 2022 audited Consolidated Financial Statements mean Suncor’s audited Consolidated Financial Statements prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), the notes thereto and the auditor’s report thereon, as at and for each year in the two-year period ended December 31, 2022. References to the annual 2022 MD&A mean Suncor’s Management’s Discussion and Analysis for the year ended December 31, 2022, dated March 6, 2023.

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, many of which are beyond the company’s control. Many of these risk factors and other assumptions related to Suncor’s forward-looking statements are discussed in further detail throughout this AIF and the company’s annual 2022 MD&A under the heading Risk Factors, which section is incorporated by reference herein and available on Suncor’s SEDAR profile at sedar.com. Users of this information are cautioned that actual results may differ materially from those expressed or implied by the forward-looking statements contained herein. Refer to the Advisory – Forward-Looking Information and Non-GAAP Financial Measures section of this AIF for information on risk factors and the 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.

Table of Contents

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 from 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 use 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 a lower sulphur content is referred to as **sweet synthetic crude oil**, while SCO with a 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, it 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 an 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 their 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 to support production in an existing field, such as observation wells or wells drilled for the purpose of injecting gas, steam or water.

Sidetrack wells are drilled from existing wells. Operations start first by abandoning the lateral section of an existing well and subsequently drilling and completing a new lateral section. The sidetracked well is then tied in to the existing wellhead and uses the existing surface facilities.

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 blended 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 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 the 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 refers to a froth treatment process whereby a lighter diluent or solvent that contains paraffin is used to selectively remove some of the asphaltenes (the highest carbon component of the barrel) from the final product. This results in a lower carbon, higher quality bitumen that can be sold directly to market without further upgrading.

Production sharing contracts 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 production sharing contract, which also states which parties are responsible for exploration activities.

Steam-assisted gravity drainage (SAGD) is an enhanced oil recovery technology for producing 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. 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 is a metric used to quantify the cubic metres of water (converted to steam) required to produce one cubic metre of oil. Different reservoirs have different steam-to-oil ratios primarily due to differences in reservoir characteristics like oil viscosity, thickness, and permeability, but within similar reservoir characteristics, the ratio is a good measure of thermal efficiency. 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 content 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.

Table of Contents

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
GHG	greenhouse gas
mmbtu	millions of British thermal units
API	American Petroleum Institute
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
NO_2	nitrogen dioxide
NOx	nitrogen oxides
SO_2	sulphur dioxide
m^3	cubic metres
m^3/d	cubic metres per day
m^3/s	cubic metres per second
km	kilometres
MW	megawatts
GWh	gigawatt hours
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 disclosed 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 – 6 th Avenue S.W., Calgary, Alberta, T2P 3E3.

Intercorporate Relationships

Suncor's material subsidiaries, held either directly or indirectly, by the company as at December 31, 2022, are shown below.

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 the upstream Canadian businesses is marketed. This subsidiary also administers Suncor's energy trading activities and power business, markets certain third-party products, procures natural gas for its upstream and downstream business, and procures crude oil feedstock and markets NGLs and LPG for its downstream business.
Suncor Energy Ventures Corporation	Alberta	A subsidiary that indirectly owns a 36.74% ownership in the Syncrude joint operation.
Suncor Energy Ventures Partnership	Alberta	A subsidiary that 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 the company's U.S. refining and marketing operations are conducted.
International operations		
Suncor Energy UK Limited	U.K.	A subsidiary through which the majority of the company's North Sea operations are conducted.

The company's remaining subsidiaries each accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2022, and (ii) less than 10% of the company's consolidated revenues for the fiscal year ended December 31, 2022. In aggregate, the remaining subsidiaries accounted for less than 20% of the company's consolidated assets as at December 31, 2022, and less than 20% of the company's consolidated revenues for the fiscal year ended December 31, 2022.

General Development of the Business

Overview

Suncor is an integrated energy company headquartered in Calgary, Alberta, Canada. Suncor's operations include oil sands development, production and upgrading; offshore oil and gas; petroleum refining in Canada and the U.S.; and the company's Petro-Canada™ retail and wholesale distribution networks (including Canada's Electric Highway™, a coast-to-coast network of fast-charging electric vehicle stations). Suncor is developing petroleum resources while advancing the transition to a low-emissions future through investments in power, renewable fuels and hydrogen. Suncor also conducts energy trading activities focused principally on marketing and trading crude oil, natural gas, byproducts, refined products and power. Suncor has been recognized for its performance and transparent reporting on the Dow Jones Sustainability World Index, FTSE4Good Index and CDP. Suncor's common shares (symbol: SU) are listed on the TSX and NYSE.

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, produces bitumen from mining and in situ operations. Bitumen is either upgraded into SCO for refinery feedstock and diesel fuel, or blended with diluent for refinery feedstock or direct sale to market through the company's midstream infrastructure and its marketing activities. The segment includes the marketing, supply, transportation and risk management of crude oil, natural gas, power and byproducts. The Oil Sands segment includes:

- **Oil Sands operations** refer to Suncor's owned and operated mining, extraction, upgrading, in situ and related logistics, blending 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. This infrastructure includes utilities, energy, reclamation and storage facilities, the interconnecting pipelines between Suncor's Oil Sands Base operations and Syncrude, and the new hot bitumen transfer piping that connects Fort Hills to Oil Sands Base. Oil Sands Base also includes mining development opportunities, including interests in Base Mine Extension (100%) and Audet (100%).
  - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, including central processing facilities, cogeneration units, product transportation infrastructure, diluent import capabilities, storage assets and a cooling and blending facility. In Situ also includes development opportunities that may support future in situ production, including interests in Meadow Creek (75%), Lewis (100%), OSLO (77.78%), Gregoire (100%), various interests in Chard (25% to 50%) and a non-operated interest in Kirby (10%). In Situ production is either upgraded by Oil Sands Base, or blended with diluent and marketed directly to customers.
- **Fort Hills** includes Suncor's interest in the Fort Hills mining and extraction operation, which the company operates, and the East Tank Farm Development, in which Suncor holds a 51% interest and operates. Subsequent to 2022, Suncor acquired an additional 14.65% working interest in Fort Hills from Teck Resources Limited (Teck), increasing the company's and its affiliate's total aggregate working interest to 68.76%.
- **Syncrude** refers to Suncor's 58.74% interest in the oil sands mining and upgrading operation, which the company operates.

Exploration and Production

Suncor's Exploration and Production (E&P) segment consists of offshore operations off the east coast of Canada and in the U.K. North Sea, and onshore assets in Libya and Syria. This segment also includes the marketing and risk management of crude oil and natural gas.

- **E&P Canada** operations include Suncor's 48% working interest in Terra Nova, which Suncor operates. Production at Terra Nova has been shut in since the fourth quarter of 2019. Investment in the Terra Nova Floating Production, Storage and Offloading (FPSO) facility related to the Asset Life Extension (ALE) Project was substantially progressed in 2022, and the asset has returned to Canada, with a safe return to production expected in the second quarter of 2023. In the second quarter of 2022, Suncor and the joint venture owners announced the decision to restart the West White Rose Project. In connection with the decision to restart the West White Rose Project, Suncor increased its interest in the White Rose assets by 12.5% to 40% in the base project and 38.6% in the extensions. Production from the West White Rose Project is expected to commence in the first half of 2026. Suncor also holds non-operated interests in Hibernia (20% in the base project and 19.485% in the Hibernia Southern Extension Unit) and Hebron (21.034%). In addition, the company holds interests in several exploration licences and significant discovery licences offshore Newfoundland and Labrador.
- **E&P International** operations include Suncor's non-operated interests in Buzzard (29.89%) and the Rosebank future development project (40%), both of which are located in the U.K. sector of the North Sea. In 2022, Suncor announced its intention to divest its U.K. assets. Subsequent to 2022, the company reached an agreement for the sale of its U.K. E&P portfolio, which is expected to close in mid-2023. In the third quarter of 2022, Suncor completed the sale of its assets in Norway, which included its 30% working interest in Oda and 17.5% working interest in the Fenja project. In addition, Suncor owns, pursuant to EPSAs, working interests in the exploration and development of oilfields in the Sirte Basin in Libya. The Libya assets continued to produce at reduced rates during 2022. The timing of a return to normal operations in Libya remains uncertain due to continued political unrest. Suncor also owns, pursuant to a production sharing contract, an interest in the Ebla gas development in Syria, which has been suspended indefinitely since 2011 due to political unrest in the country.

Refining and Marketing

Suncor's Refining and Marketing segment consists of two primary operations: the Refining and Supply and Marketing operations discussed below, as well as the infrastructure supporting the marketing, supply and risk management of refined products, crude oil, natural gas, power and byproducts. This segment also includes the trading of crude oil, refined products, natural gas and power.

- **Refining and Supply** operations refine crude oil and intermediate feedstock into a wide range of petroleum and petrochemical products. Refining and Supply consists of:
  - **Eastern North America** operations include a 137 mbbls/d refinery located in Montreal, Quebec, and an 85 mbbls/d refinery located in Sarnia, Ontario.
  - **Western North America** operations include a 146 mbbls/d refinery located in Edmonton, Alberta, and 98 mbbls/d refinery in Commerce City, Colorado, that is comprised of three plants at two refineries. For simplicity, Suncor refers to this as the Commerce City refinery.
  - Other Refining and Supply assets include interests in a petrochemical plant and a sulphur recovery facility in Montreal, Quebec, product pipelines and terminals throughout Canada and the U.S., and the St. Clair ethanol plant in Ontario.
- **Marketing** operations sell refined petroleum products to retail customers primarily through a combination of company-owned Petro-Canada™ locations, branded dealers in Canada and company-owned locations in the U.S. marketed under other international brands. This

includes Canada's Electric Highway™, a coast-to-coast network of fast-charging electric vehicle stations. The company's marketing operations also sells refined petroleum products through a nationwide commercial road transportation network in Canada, and to other commercial and industrial customers, including other retail sellers, in Canada and the U.S.

Corporate and Eliminations

The Corporate and Eliminations segment includes activities not directly attributable to any other operating segment. This segment previously included renewable energy assets, which were sold in the first quarter of 2023.

- **Corporate** activities include stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, and investments in clean technology, such as Suncor's investment in Enerkem Inc., LanzaJet, Inc., Svante Inc., the Varennes Carbon Recycling facility, the Pathways Alliance, and the early-stage design and engineering for the proposed ATCO/Suncor hydrogen project.
- Intersegment revenues and expenses are removed from consolidated results in **Eliminations**. Intersegment activity includes the sale of product between the company's segments, primarily relating to crude refining feedstock sold from Oil Sands to Refining and Marketing.

Three-Year History

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

2020

- **The COVID-19 pandemic.** On January 30, 2020, the World Health Organization declared the Coronavirus disease (COVID-19) outbreak a Public Health Emergency of International Concern and, on March 10, 2020, declared it to be a pandemic. The impacts of the COVID-19 pandemic resulted in significant disruptions to the company's business operations and a significant increase in economic uncertainty, with fluctuating demand for commodities contributing to volatile prices.
- **Debt issuance and enhanced liquidity.** To help strengthen the financial resiliency of the company, Suncor secured $2.8 billion in additional credit facilities (which were subsequently cancelled in the first quarter of 2021) and issued $1.25 billion of 5.00% senior 10-year unsecured medium-term notes, US$450 million of 2.80% senior three-year unsecured notes and US$550 million of 3.10% senior five-year unsecured notes in 2020.
- **Share repurchases.** During the first quarter of 2020, the company repurchased 7.5 million of the company's common shares for cancellation at an average price of $40.83 per common share, for a total repurchase cost of $307 million. Subsequently, in response to the impacts of the COVID-19 pandemic, the company elected to suspend share repurchases and did not renew its normal course issuer bid (NCIB).
- **Dividend reduction.** In response to the uncertainty created by the COVID-19 pandemic, in the second quarter of 2020, the Board approved a reduction in the company's quarterly dividend to $0.21 per common share from $0.465 per common share.
- **Continuing investment in global energy expansion.** During the second quarter of 2020, Suncor made an equity investment in LanzaJet, Inc., a company that is working to bring sustainable aviation fuel and renewable diesel to the commercial market. In addition, in the fourth quarter of 2020, Suncor, Enerkem Inc. and other partners announced plans for the construction of a biorefinery in Varennes, Quebec. The Varennes Carbon Recycling facility is designed to convert commercial and industrial non-recyclable waste into biofuels and renewable chemicals. These strategic investments, together with the company's equity investment in Enerkem Inc. in 2019, complement Suncor's existing product mix and demonstrate Suncor's involvement in the evolving global energy expansion.

- **Temporary transition to one-train operation at Fort Hills.** During the second quarter of 2020, in response to the impacts of the COVID-19 pandemic, the Fort Hills partners agreed to temporarily reduce Fort Hills from operating two primary extraction trains to a one-train operation.
- **Deployment of autonomous haulage systems at Fort Hills.** The company deployed autonomous haulage systems at its Fort Hills mine in 2020. 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. Subsequently, operations temporarily returned to a staffed fleet at Fort Hills.
- **Execution of Firebag debottlenecking activities.** Suncor accelerated maintenance at Firebag, which allowed the company to integrate and fully utilize additional steam and water treatment assets. The maintenance was completed in the fourth quarter of 2020 and the nameplate capacity of the facilities increased from 203 mbbls/d to 215 mbbls/d of bitumen.
- **Interconnecting pipelines between Suncor's Oil Sands Base and Syncrude.** The interconnecting pipelines, which connect Syncrude's Mildred Lake site and Suncor's Oil Sands Base operations, enhance integration between these assets and provide increased operational flexibility through the ability to transfer bitumen and sour SCO between the two plants, enabling higher upgrader utilization. The asset was brought into service and transfers began in December 2020, reflecting the enhanced integration and operational flexibility between these assets.
- **West White Rose Project placed in safe mode.** The operator of the project announced a full project review given the continued market uncertainty as a result of the COVID-19 pandemic, along with the cancellation of the 2021 construction season and moved the project into safekeeping mode.
- **Workforce reductions and downstream restructuring.** In the fourth quarter of 2020, Suncor announced that it would be making workforce reductions of 10% to 15% of employees by mid-2022. Furthermore, Suncor announced its decision to relocate the company's downstream offices in Mississauga and Oakville, Ontario, to Calgary, Alberta.

2021

- **Restart of share repurchases.** On February 3, 2021, the TSX accepted a notice filed by Suncor to commence a new NCIB to repurchase up to 44,000,000 of the company's common shares beginning on February 8, 2021, and ending February 7, 2022, through the facilities of the TSX, NYSE and/or alternative trading platforms.
- **Investment in clean energy.** During the first quarter of 2021, Suncor announced an equity investment in Svante Inc., a Canadian carbon capture company. With support from Suncor and other companies, Svante plans to continue developing its technology to capture CO_2 from industrial processes at reduced costs. Carbon capture is a strategic technology area for Suncor to reduce GHG emissions in Suncor's base business and produce blue hydrogen as an energy product. In the fourth quarter of 2021, Suncor increased its equity interest in the Varennes Carbon Recycling facility.
- **Debt reduction.** During the first quarter of 2021, consistent with its debt management and reduction strategy, Suncor cancelled $2.8 billion in bilateral credit facilities that were no longer required, as they were entered into in March and April of 2020 to ensure access to adequate financial resources in connection with the COVID-19 pandemic. In addition, Suncor also exercised the early redemption options on its outstanding US$220 million of 9.40% senior unsecured notes and $750 million 3.10% medium-term notes, both due in 2021. During the first quarter of 2021, the company also issued US$750 million of 3.75% senior unsecured notes and $500 million of 3.95% senior unsecured medium-term notes, both due on March 4, 2051.

- **Updated strategy focused on shareholder returns and GHG emissions reductions.** On Suncor's Investor Day on May 26, 2021, the company outlined its medium-term outlook for structural cost reductions, a stronger balance sheet, improved margin capture and a sustainable increase of cash returns to shareholders while strengthening the company's environmental performance. In addition, the strategy included the goal for Suncor to become a net-zero GHG emissions company by 2050 (on emissions produced from running its facilities, including those in which it has a working interest) and to substantially contribute to society's net-zero ambitions. While Suncor will continue to track and report emissions intensity, the company has set ambitious near-term goals to reduce emissions across its value chain.
- **Oil Sands Pathways to Net Zero Alliance.** Suncor, together with Canadian Natural Resources Limited, Cenovus Energy Inc., Imperial Oil Resources Limited and MEG Energy Corp., announced the Oil Sands Pathways to Net Zero alliance, which was expanded to include ConocoPhillips Canada Resources Corp. in November 2021. The alliance's goal was to work collectively with the federal and provincial governments to achieve net-zero GHG emissions from oil sands operations by 2050. The alliance explored several parallel pathways to address GHG emissions, including the creation of a carbon capture, utilization and storage trunkline connected to a carbon sequestration hub to enable multisector "tie-in" projects and the implementation of other next-generation technologies.
- **Suncor assumes operatorship of Syncrude.** Pursuant to an agreement between the Syncrude joint venture owners, Suncor assumed the role of operator of the Syncrude joint operation on September 30, 2021, a critical step towards driving greater integration, efficiencies and competitiveness across all Suncor-operated assets in the region.
- **Completed sale of the Golden Eagle Area Development.** In the fourth quarter of 2021, the company completed the sale of its 26.69% working interest in the Golden Eagle Area Development for gross proceeds of US$250 million net of closing adjustments and other closing costs, in addition to future contingent consideration of up to US$50 million. The effective date of the sale was January 1, 2021.
- **Terra Nova ALE Project moving forward.** Suncor and the co-owners of the Terra Nova project finalized an agreement to restructure the project ownership and move forward with the ALE Project, which is expected to extend production life by approximately 10 years. As a result of the agreement, Suncor increased its ownership in the project by approximately 10% to 48%.
- **Conditional agreement reached to increase interest in the West White Rose Project.** Suncor entered into a conditional agreement to increase its interest in the White Rose assets, subject to a number of conditions, including an economic restart decision for the West White Rose Project by mid-2022.
- **First oil achieved at Buzzard Phase 2.** Buzzard Phase 2, which will extend production life of the existing Buzzard field, achieved first oil in the fourth quarter of 2021.
- **Historic partnership with Indigenous communities.** Suncor, together with eight Indigenous communities, acquired a 15% equity interest in the Northern Courier Pipeline in the fourth quarter of 2021. The Northern Courier Pipeline, which connects the Fort Hills asset to Suncor's East Tank Farm, is now operated by Suncor and is expected to provide the eight Indigenous communities with reliable income for decades.
- **Dividend increase and acceleration of the share repurchase program.** In the fourth quarter of 2021, the Board approved a quarterly dividend of $0.42 per share, reinstating the quarterly dividend to 2019 levels. The Board also approved an increase to the company's NCIB to approximately 7% of Suncor's public float as at January 31, 2021, and concurrently, the TSX accepted a notice to increase the maximum number of common shares the company may repurchase pursuant to its NCIB to 7% of the company's public float.

- **Continuation of share repurchases.** Since the start of its NCIB in February 2021, the company repurchased approximately 84 million of its common shares at an average price of $27.45 per common share, or the equivalent of 5.5% of Suncor's public float as at January 31, 2021.
- **Fort Hills resumed operation of the second primary extraction train.** Fort Hills resumed two-train operations late in the fourth quarter of 2021.

2022

- **Share repurchases.** In 2022, the company repurchased 116.9 million of its common shares at an average share price of $43.92 per common share, or the equivalent of 8.1% of its issued and outstanding common shares as at December 31, 2021.
- **Dividend increases.** In the second and fourth quarters of 2022, the Board approved increases to the quarterly dividend, raising it to $0.47 per share and $0.52 per share, respectively, both of which were the highest quarterly dividends per share in the company's history.
- **Renewal of share repurchase program.** In the first quarter of 2022, the Board approved a renewal of the company's NCIB for the repurchase of approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2022, over a twelve-month period, and concurrently, the TSX accepted a notice filed by Suncor to renew its NCIB in respect of the repurchase of such shares. During the second quarter of 2022, the NCIB was amended to allow the repurchase of up to 10% of Suncor's public float. Subsequent to 2022, the Board approved a renewal of the company's NCIB for the repurchase of up to 10% of Suncor's public float as at February 3, 2023, over a twelve-month period, and concurrently, the TSX accepted a notice filed by Suncor to renew its NCIB in respect of the repurchase of such shares.
- **Executed debt tender offer.** In the fourth quarter of 2022, the company completed a debt tender offer and as a result, repaid approximately $3.6 billion of its various series of outstanding notes below par.
- **Restart of West White Rose Project.** In the second quarter of 2022, Suncor and the joint venture owners announced the decision to restart the West White Rose Project offshore the east coast of Canada, which is expected to extend the production life of the White Rose field. As a result of the restart decision, Suncor has increased its ownership in the White Rose assets by an additional 12.5% to approximately 39%. Production from the West White Rose Project is expected to commence in the first half of 2026.
- **Kris Smith appointed interim President and Chief Executive Officer.** Mr. Smith was named interim President and Chief Executive Officer, replacing Mark Little, as at July 8, 2022.
- **Suncor enters into agreement with Elliott Investment Management.** In the third quarter of 2022, Suncor entered into an agreement with affiliates of Elliott Investment Management (Elliott), pursuant to which Suncor appointed three new independent directors to its Board. Subsequent to 2022, the agreement was amended to extend the right for Elliott to appoint an additional director to the board from January 31, 2023, to March 17, 2023.
- **Completed sale of Norway operations.** In the third quarter of 2022, the company completed the sale of its E&P assets in Norway for gross proceeds of approximately $430 million, before closing adjustments and other closing costs.
- **Sale of the wind and solar assets.** Subsequent to 2022, Suncor completed the sale of its wind and solar assets for gross proceeds of approximately $730 million, before closing adjustments and other closing costs, to focus on hydrogen and renewable fuels to accelerate progress towards its objective to be a net-zero GHG emissions company by 2050. The sale included the company's interest in Magrath, Chin Chute, Adelaide and Forty Mile wind farms, as well as development stage renewable power assets.

- **Sale of U.K. assets.** In 2022, Suncor announced its intention to divest its U.K. E&P portfolio which include Buzzard and the Rosebank future development project. Subsequent to 2022, the company reached an agreement for the sale of its U.K. E&P portfolio for gross proceeds of approximately $1.2 billion, including a contingent consideration of approximately $338 million, before closing adjustments and other closing costs. The sale is pending regulatory approval and is expected to close in mid-2023.
- **Acquired additional interest in Fort Hills.** During the fourth quarter of 2022, the company entered into an agreement to acquire Teck's 21.3% interest in the Fort Hills Project (Fort Hills) and its associated sales and logistics agreements for $1.0 billion, subject to working capital and other closing adjustments. Subsequent to the fourth quarter of 2022, TotalEnergies EP Canada Ltd. provided notice of the exercise of its contractual right of first refusal to acquire from Teck a 6.65% interest in Fort Hills, which reduced the amount of working interest available for Suncor to purchase. As a result, on February 2, 2023, Suncor completed the acquisition of an additional 14.65% working interest in Fort Hills for $688 million, before working capital and other closing adjustments, bringing the company's and its affiliate's total aggregate working interest in Fort Hills to 68.76%.
- **Fort Hills mine improvement plan.** In the fourth quarter of 2022, the company commenced its three-year mine improvement plan, which includes an accelerated sequence of mine development relative to historical plans, during which time the asset is expected to operate at lower than 90% production rates.
- **Results of retail review.** In the fourth quarter of 2022, as a result of a comprehensive strategic review of its downstream retail business, the company announced that it would retain and continue to improve and optimize the Petro-Canada™ retail business.
- **Pathways Alliance awarded exploratory rights.** Subsequent to 2022, the Pathways Alliance was awarded exploratory rights from the Government of Alberta for the proposed carbon capture and storage hub to safely and permanently store CO_2 captured from over 20 oil sands facilities in northern Alberta.
- **Rich Kruger appointed new President and Chief Executive Officer.** Subsequent to 2022, Mr. Kruger was named Suncor's next President and Chief Executive Officer, effective April 3, 2023. Kris Smith will assume the role of Chief Financial Officer and Executive VP of Corporate Development at the conclusion of the company's annual general meeting on May 9, 2023. Alister Cowan, current Chief Financial Officer, plans to retire but will remain with the company to the end of 2023 to support transition to Mr. Smith and provide advisory services.

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 section of this AIF and the Risk Factors section of the company's annual 2022 MD&A, which section is incorporated by reference herein and available on Suncor's SEDAR profile at sedar.com.

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.

- **Transportation**

Suncor has regional pipelines that connect the company's mining, in situ, upgrading and storage assets, providing optionality and improving upgrader utilization and optimization of bitumen value for Suncor.

Additionally, interconnecting pipelines connect Syncrude's Mildred Lake site and Suncor's Oil Sands Base operations. The pipelines provide increased operational flexibility through the ability to transfer bitumen and sour SCO between the two plants, enabling higher upgrader utilization. The pipelines create flexibility for Syncrude to sell intermediate products to Suncor, which include bitumen and sour SCO.

- **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 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 revegetation.

Oil sands tailings are the remaining sand, water, clay, silt and residual hydrocarbons left after most 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 dewatering and treatment of mature fine tailings at Oil Sands Base, including the construction of a permanent aquatic storage structure. 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 2022, the company mined approximately 147.1 million tonnes of bitumen ore (2021 –150.8 million tonnes) and processed an average of 256.9 mbbls/d of mined bitumen in its extraction facilities (2021 –276.2 mbbls/d).

Upgrading Facilities

Suncor's upgrading facilities consist of two upgraders: Upgrader 1, which has a capacity of approximately 110 mbbls/d of SCO, and Upgrader 2, which has a 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 kerosene hydrotreater.

Suncor has progressed with its project to replace the existing coke-fired boilers at Oil Sands Base with a new 800 MW cogeneration facility. The project is expected to provide steam generation required for Suncor's extraction and upgrading activities and is expected to reduce the GHG emissions intensity associated with steam production at Oil Sands Base by approximately 25%. In addition, the excess electricity produced will be transmitted to Alberta's power grid, providing reliable, baseload, low-carbon electricity, equivalent to approximately 8% of Alberta's current electricity demand. In total, this project is expected to reduce GHG emissions in the province of Alberta by approximately 5.1 Mt per year. The project is estimated to cost approximately $1.4 billion with an expected in service date in late 2024.

During 2022, Suncor's Oil Sands Base assets averaged 314.6 mbbls/d of upgraded (SCO and diesel) production, mainly sourced from bitumen provided by both Oil Sands Base and In Situ operations, including the company's internal consumption and transfers through the interconnecting pipelines (2021 –313.7 mbbls/d). In the 2021 AIF, the company revised the presentation of current and prior year upgraded Oil Sands Base production to include internally consumed diesel volumes and transfers through the interconnecting pipelines with Syncrude.

Other Mining Leases

Suncor owns interests in several other mineable oil sands leases, including Base Mine Extension 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 Base Mine Extension 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 the 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 that use natural gas combustion to power turbines that generate electricity and steam used in SAGD operations. Excess electricity generation from cogeneration units is used at Oil Sands Base facilities or sold to the 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 215 mbbls/d of bitumen.

As at December 31, 2022, Firebag had 21 well pads in operation, with 284 SAGD well pairs and 55 infill wells either producing or on initial steam injection. Central processing facilities have been designed to provide some flexibility 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 112 MW and, in 2022, Firebag exported approximately 245 MW of electricity to the Alberta power grid and Oil Sands Base. There are also 13 OTSGs at the site for additional steam generation.

During 2022, Firebag production averaged 198.9 mbbls/d of bitumen (2021 –206.4 mbbls/d) with a steam-to-oil ratio of 2.7 (2021 –2.6).

MacKay River

Production from Suncor's MacKay River operations commenced in 2002. The MacKay River central processing facilities have a bitumen processing capacity of 38 mbbls/d. As at December 31, 2022, MacKay River included nine well pads with 132 well pairs either producing or on initial steam injection. A third-party owns the on-site cogeneration unit, which Suncor operates that generates steam and electricity. There are also four OTSGs at the site for additional steam generation.

During 2022, MacKay River production averaged 32.4 mbbls/d of bitumen (2021 –35.9 mbbls/d) with a steam-to-oil ratio of 2.8 (2021 –2.8).

Other In Situ Leases

Suncor holds a large portfolio of In Situ lands in proximity to Fort McMurray. Two properties, Lewis and Meadow Creek, have received regulatory approval for future production. Suncor holds a 100% working interest in Lewis and Gregoire, a 75% working interest in Meadow Creek, a 77.78% working interest in OSLO, interests varying from 25% to 50% in Chard, and a 10% non-operated interest in Kirby. The portfolio is well positioned to leverage Suncor's existing asset base and is currently being evaluated as part of Suncor's integrated Bitumen Supply Strategy.

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 mining and extraction assets; however, Fort Hills uses a paraffinic froth treatment 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.

Fort Hills began producing paraffinic froth treated bitumen from secondary extraction in early 2018. Fort Hills has a nameplate capacity of 194 mbbls/d (gross) of bitumen. During 2022, Suncor's share of Fort Hills production averaged 85.1 mbbls/d of bitumen (2021 –50.7 mbbls/d) from approximately 53.5 million tonnes of bitumen ore mined (2021 –32.6 million tonnes).

Suncor is the operator of the Fort Hills asset. In the fourth quarter of 2022, the company commenced its three-year mine improvement plan, which includes an accelerated sequence of mine development relative to historical plans, during which time the asset is expected to operate at lower than 90% production rates. Short-term production and operating cost impacts are expected in 2023 as the company develops the Centre and North pits while building adequate ore inventory. On February 2, 2023, Suncor completed the acquisition of an additional 14.65% working interest in Fort Hills from Teck for $688 million, before working capital and other closing adjustments, bringing the company's and its affiliate's total aggregate working interest in Fort Hills to 68.76%.

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). Syncrude began producing in 1978 and is located near Fort McMurray. It includes mining operations at Mildred Lake and Aurora North. On September 30, 2021, the operatorship of Syncrude was formally transferred to Suncor, concurrent with the ratification of the Joint Venture Operating Agreement, and the previous Management Services Agreement with Imperial Oil was cancelled.

In 2015, the joint venture owners agreed to progress with the Mildred Lake West Extension (MLX-W) program which 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. The Syncrude MLX-W mining area received AER approval in 2019 and additional approvals in 2020. First oil is expected in late 2025. The Mildred Lake East Extension (MLX-E) program will follow the MLX-W development if economic conditions remain suitable.

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 that provide heat and electricity.

Syncrude produces a sweet SCO product; individual joint venture owners are responsible for marketing this product. In addition, interconnecting pipelines between Syncrude's Mildred Lake site and Suncor's Oil Sands Base operations create flexibility for Syncrude to sell intermediate products to Suncor, which include bitumen, coker naphtha and sour SCO.

Land reclamation activities at Syncrude are similar to those at Oil Sands Base; however, certain aspects of the tailings management processes at Syncrude are different. Syncrude's current tailings plan uses freshwater capping, a composite tails mixture of fine tails and gypsum, and centrifuge technology that separates water from tailings. The updated tailings management plans for Syncrude Aurora North and Syncrude Mildred Lake were approved by the AER in June 2018 and June 2019, respectively.

In 2022, Suncor's share of Syncrude production, including internal consumption and transfers through the interconnecting pipelines, averaged 184.8 mbbls/d of SCO, intermediate products and bitumen (2021 – 172.4 mbbls/d).

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 Lease 31, through the company's 58.74% working interest in the Syncrude joint operation.

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 feasibility and then to demonstrate commercial viability. The necessary validation typically occurs through a series of progressive steps that allow results to be reliably scaled and assessed for implementation.

Following a successful commercial-scale evaluation in 2018, the company began a phased implementation of autonomous haulage systems at its operated mine sites. Autonomous haulage systems were deployed at the North Steepbank mine in 2018 and at Fort Hills in 2020. Subsequently, in 2021, Fort Hills temporarily returned to a staffed fleet to better manage congestion and interactions between staffed and autonomous operations. Full implementation at the Oil Sands Base Millennium mine is expected to be completed over the next four years.

Building upon the process used in Suncor's Tailings Reduction Operations (TRO™), Suncor has developed the permanent aquatic storage structure (PASS) fluid tailings treatment process to significantly increase the amount of fluid tailings it can treat in a more sustainable manner. PASS combines the TRO™ process with the addition of a coagulant to improve the quality of the water expressed from the treated fluid tailings. With the implementation of PASS technology, Suncor has reduced tailings volumes by more than 5% since 2020. The total number of active tailings ponds has been reduced since 2010, with one being surface reclaimed and three more advancing to closure.

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:

- Expanding Solvent SAGD – An enhancement of SAGD technology wherein a small volume of hydrocarbon solvent is co-injected with steam. The addition of the hydrocarbon solvent accelerates bitumen production and lowers the steam-to-oil ratio (i.e., GHG emissions intensity). This technology was successfully piloted in a half-pad configuration at Firebag in 2019-2021 and a follow-up full-pad commercial demonstration began at Firebag in the fourth quarter of 2022, focused on demonstrating a material improvement in both environmental and

economic performance. Pending a successful demonstration, the technology is expected to be ready for commercial deployment in Suncor's In Situ projects as early as 2027.

- Solvent-dominated recovery process – A solvent technology wherein a hydrocarbon solvent is mixed with low-pressure steam (>80% solvent) and injected into the reservoir. The combined solvent and thermal effect are expected to materially lower the energy requirements and result in a potential step-change in both economic and environmental performance, including a greater than 50% reduction in emissions intensity relative to SAGD.
- Non-Aqueous Extraction (NAE) – NAE is a potential new extraction process for oil sands mining operations that uses solvents, as opposed to water, as the primary extraction means. This has the potential to reduce water usage and tailings, and simplify extraction processes, while reducing costs and GHG emissions.

Sales of Principal Products

Primary markets for SCO and bitumen production from Suncor's Oil Sands segment 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 the company's Edmonton refinery or selling diluted bitumen to third parties. In the normal course of business, Suncor enters into long-term sales agreements, which contain varying terms with respect to pricing, volume, expiry and termination. In Situ bitumen production processed by Oil Sands Base upgrading facilities in 2022 increased to 130.2 mbbls/d or 56% (2021 –116.8 mbbls/d or 48%) of total In Situ bitumen production as less In Situ bitumen feedstock was required due to higher mined bitumen feedstock and imports of bitumen from Syncrude on the interconnecting pipelines.

	2022		2021	
Sales Volumes and Operating Revenues - Principal Products	mbbls/d	% Operating Revenues	mbbls/d	% Operating Revenues
SCO and diesel (including Syncrude)	482.6	77	465.7	70
Bitumen	180.7	21	183.8	27
Byproducts and other operating revenues (1)	n/a	2	n/a	3
	663.3		649.5	

(1) Operating revenues include revenues associated with excess electricity 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, which contain varying terms with respect to pricing, volume, expiry and termination.

Distribution of Products

Production from Oil Sands operations and Fort Hills is gathered into Suncor's Fort McMurray facilities at the Athabasca Terminal, which is operated by Enbridge Inc., or the East Tank Farm, which is operated by Suncor and connected to the Athabasca Terminal. Suncor has arrangements with Enbridge to store SCO, diluted bitumen and diesel at the Athabasca Terminal. 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 on the Enbridge Mainline or the Trans Mountain Pipeline system.
- To Cheecham, Alberta, on the Enbridge Athabasca Pipeline or the Enbridge Wood Buffalo Pipeline and 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, and via the mainline from Rose Rock's Platteville Terminal to Suncor's Fort Lupton Station. 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 and from South Portland, Maine, on the Portland Montreal Pipeline.
- 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 Trans Mountain Pipeline, as well as by rail.

Production from Syncrude is moved to market via the Pembina Athabasca Oil Sands Pipeline.

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. 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 2022, Suncor incurred royalties at an average rate of 12% of gross revenue for Oil Sands Operations projects, which include Base Mine, MacKay River and Firebag, (2021 –4%), and at an average rate of 18% of gross revenue for Syncrude operations (2021 –13%) due to higher prices. Oil Sands Operations projects and the Syncrude project are in the post-payout phase, with assessment for the year for Oil Sands Base at GRR due to a carry-forward costs balance, and MacKay River, Firebag and Syncrude at NRR.

Fort Hills is in the pre-payout phase. In 2022, Fort Hills incurred royalties at an average rate of 5% of gross revenue (2021 –2%) due to higher prices.

Exploration and Production

E&P Canada – Assets and Operations

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 kilometres 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 an FPSO vessel that is moored on location, and has gross production capacity of 180 mbbls/d (86 mbbls/d, net to Suncor) of crude oil and an oil storage capacity of 960 mbbls. Terra Nova was the first harsh environment development in North America to use an FPSO vessel. 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.

Terra Nova has been offline since the fourth quarter of 2019. In 2020, the company safely preserved the FPSO quayside and deferred the previously announced ALE Project until an economically viable path forward with a safe and reliable return to operations could be determined. In 2021, Suncor and the co-owners of the Terra Nova project finalized an agreement to restructure the project ownership and move forward with the ALE Project. Under this agreement, the company's working interest increased to 48% from approximately 38% in exchange for a cash payment from the exiting owners. This agreement also included royalty and financial support from the Government of Newfoundland and Labrador.

The ALE Project was substantially progressed in 2022, and the asset has returned to Canada, with a safe return to production expected in the second quarter of 2023. The Terra Nova ALE Project is expected to extend the production life of the Terra Nova field by approximately 10 years, providing many benefits to the Newfoundland and Labrador and Canadian economies in the form of taxes, royalties and employment.

In 2022, Terra Nova production remained offline; therefore, Suncor's share of Terra Nova production averaged nil mbbls/d of crude oil (2021 – nil mbbls/d).

Hibernia and the Hibernia Southern Extension Unit

The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is approximately 315 kilometres southeast of St. John's and was the first field to be developed in the Jeanne d'Arc Basin. Operated by Hibernia Management and Development Company Ltd., the production system is a fixed Gravity Based Structure (GBS) that sits on the ocean floor and has gross production capacity of 230 mbbls/d (46 mbbls/d, net to Suncor) of crude oil, and an oil storage capacity of 1,300 mbbls. Actual production levels are lower due to natural reservoir declines. Hibernia commenced production in November 1997. As at December 31, 2022, there were 74 wells: 41 oil production wells, 27 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 Hibernia Southern Extension Unit (HSEU). At the end of 2022, there were eight 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 2022, Suncor's share of Hibernia production averaged 15.1 mbbls/d of crude oil (2021 –19.8 mbbls/d).

White Rose and the White Rose Extensions

White Rose is approximately 350 kilometres southeast of St. John's. Operated by Cenovus Energy Inc. (previously Husky Oil Operations Limited), White Rose uses an FPSO vessel and has gross production capacity of 140 mbbls/d (55 mbbls/d, net to Suncor) of crude oil and oil storage capacity of 940 mbbls. Actual production levels are lower than production capacity, due to natural declines and gas and water injection. Production from White Rose began in November 2005. As at December 31, 2022, there were 45 wells: 23 oil production wells, 16 water injection wells, three gas storage wells and three gas injection wells.

The White Rose Extensions 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 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, was sanctioned in 2017. Major development activity began in 2018. In 2020, the operator moved the project into safekeeping mode, due to COVID-19-related market uncertainty. During the second quarter of 2022, concurrent with the decision to restart the West White Rose Project by the joint venture owners, Suncor increased its ownership in the White Rose asset by 12.5% to approximately 39%. The project is expected to extend the life of the existing White Rose assets. Production is expected to commence in the first half of 2026.

In 2022, Suncor's share of White Rose production averaged 6.1 mbbls/d of crude oil (2021 –5.4 mbbls/d).

Hebron

The Hebron oilfield is located approximately 340 kilometres southeast of St. John's and is operated by ExxonMobil Canada Properties. The development includes a concrete GBS that sits on the ocean floor and supports an integrated topsides deck used for production, drilling and accommodations. Hebron has a gross oil storage capacity of 1,200 mbbls and 52 well slots. First oil was achieved in November 2017.

As at December 31, 2022, there were 30 wells: 20 oil production wells, five water injection wells, one gas injection well, one cuttings reinjection well and three water alternating gas injection wells. In 2022, Suncor's share of production averaged 29.0 mbbls/d of crude oil (2021 –29.2 mbbls/d).

Other Assets

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. In 2019, Suncor and Cenovus were announced as the successful bidders on exploration licence No. 1164, which is located north of White Rose. This licence carries work commitments from 2020 to 2026. In total, the company holds interests in 49 significant discovery licences and three exploration licences offshore in this area.

E&P International – Assets and Operations

Offshore U.K.

In the third quarter of 2022, the company commenced a sales process for its U.K. portfolio, including its interests in Buzzard and Rosebank located in the U.K. sector of the North Sea. Subsequent to 2022, the company reached an agreement for the sale of its U.K. E&P portfolio for gross proceeds of approximately $1.2 billion, including a contingent consideration of approximately $338 million, before closing adjustments and other closing costs. The sale is pending regulatory approval, and is expected to close in mid-2023.

Buzzard

The Buzzard oilfield is located in the Outer Moray Firth, 95 kilometres northeast of Aberdeen, Scotland. Operated by CNOOC Petroleum Europe Limited, 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 crude 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. As at December 31, 2022, there were 51 wells: 34 oil and gas production wells and 17 water injection wells. Buzzard Phase 2 was sanctioned in 2018 and first oil was achieved in November 2021. In 2022, Suncor's share of Buzzard production averaged 20.9 mboe/d of crude oil and natural gas (2021 –18.7 mboe/d).

Rosebank

The Rosebank development project, in which Suncor has a 40% working interest, was discovered in December 2004 and is operated by Equinor UK Limited. It is located approximately 130 kilometres northwest of the Shetland Islands, in the U.K. North Sea. The project is currently in the pre-sanction phase.

Other Assets

The company holds interests in 1 U.K. exploration licence offering future offshore opportunity.

Norway (Oda, Fenja)

On September 30, 2022, the company completed the sale of its 30% working interest in Oda and its 17.5% working interest in the Fenja Development Joint Operations. In 2022, Suncor's share of Oda production averaged 3.6 mboe/d of crude oil and natural gas (2021 –2.7 mboe/d).

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 ongoing political unrest, and the remaining value of Suncor's assets in Libya was impaired in 2015. The timing of a return to normal operations in Libya remains uncertain due to continued political unrest.

The estimated cost of Suncor's remaining exploration work program commitment at December 31, 2022, is US$359 million. Suncor declared force majeure for all exploration commitments in Libya effective December 14, 2014, and this declaration remains in effect.

Suncor's share of production in Libya on an economic basis averaged 3.3 mbbls/d in 2022 of crude oil (2021 – 3.4 mbbls/d).

Syria

In December 2011, due to 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. is marketed by Suncor's Energy Trading business. 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:

	2022		2021	
Sales Volumes	mboe/d	% Operating Revenues	mboe/d	% Operating Revenues
E&P Canada				
Crude oil	51.4	64	53.1	64
E&P International				
Crude oil and NGLs[1][2]	28.5	35	29.2	35
Natural gas	0.7	1	0.5	1
Total Exploration and Production				
Crude oil and NGLs[2]	79.9	99	82.3	99
Natural gas	0.7	1	0.5	1

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

(2) Contains immaterial amounts of NGLs.

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.

Royalties

East Coast Canada

Suncor's East Coast projects are subject to royalty agreements and regulations issued by the Government of Newfoundland and Labrador. To date, the royalty regime for each project has been negotiated on an individual basis. On November 1, 2017, the Province of Newfoundland and Labrador promulgated the Generic Offshore Royalty Regime for future projects. The current East Coast royalty regime has a tiered rate structure ranging from a minimum of 1% of gross revenue to a maximum of 42.5% of net revenue (gross revenue less eligible operating and capital costs). The tiered structure is based upon various profitability levels. An East Coast project will be 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).

Terra Nova royalties consist of an initial graduated-scale basic royalty, followed by a two-tiered royalty that will become payable upon the achievement of specified levels of profitability. The basic royalty starts at 1% of gross revenue, graduating to 10% depending on certain milestones. The tier one royalty is equal to 30% of net revenue. The tier two incremental royalty is on a stepped scale ranging from 10% to 22.5% to reflect oil prices from US$65/bbl Brent to above US$80/bbl Brent. During 2022, Terra Nova did not pay royalties due to suspension of production (2021 –0%).

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 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 was triggered in 2019.

Hibernia royalties (including the HSEU) and net profits interest combined to average 38% of gross revenue for 2022 (2021 –35%), due to higher commodity prices.

White Rose and the Newfoundland government finalized the White Rose Fiscal Agreement in 2022, which effected changes to the existing royalty structure. Royalties consist of an initial graduated-scale basic royalty, followed by a two-tiered royalty that will become payable upon the achievement of specified levels of profitability. The basic royalty starts at 1% of gross revenue, graduating to 7.5% depending on certain milestones. White Rose existing tier one royalty is the greater of 7.5% of gross revenue or 20% of net revenue and the tier two royalty is an additional 10% of net revenue.

The White Rose Extension (WRE) tier one royalty is equal to 10% of net revenue when Brent oil price is less than or equal to US$65/bbl, 15% when between US$65/bbl to US$80/bbl, and 30% when Brent is above US$80/bbl until tier two payout, after which the tier one royalty is 20% of net revenue. The tier two royalty is an additional 10%. The WRE also has an additional royalty equal to 1.25% to 12.50% net revenue to reflect oil prices from US$65/bbl Brent to above US$90/bbl Brent. During 2022, under the new agreement, total White Rose (including WRE) royalties averaged less than 1% of gross revenue (2021 – 6%).

The Hebron royalty structure consists of an initial sliding-scale basic royalty, followed by a three-tiered royalty that will become payable upon the achievement of specified levels of profitability. The basic royalty starts at 1% and increases 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

2022, Hebron reached simple basic payout increasing to 5% of gross revenue. Hebron royalties averaged 2% of gross revenue in 2022 (2021 – 1%).

E&P International

There are no royalties on oil and gas production from Offshore U.K. 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 segment, WCS, conventional crude oil and 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.

Production yield from the Montreal refinery includes gasoline, distillate, heavy fuel oil, solvents, asphalt and petrochemicals, which are distributed primarily across Quebec and Ontario. The Montreal refinery also produces feedstock sold under a long-term supply contract with HollyFrontier's lubricants facility. 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 segment 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 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., 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 342,500 metric tonnes in 2022 (2021 –358,000 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 2022, the plant produced 358 million litres of ethanol (2021 –343 million litres).

Western North America

Edmonton Refinery

The Edmonton refinery has a crude oil capacity of 146 mbbls/d and has the capability to run a full slate of feedstock sourced from Suncor's Oil Sands segment. Crude oil is supplied to the refinery via company-owned and third-party pipelines.

Feedstock is supplied from Suncor's Oil Sands segment and other producers from the Wood Buffalo and Cold Lake regions of Alberta. The refinery can process approximately 44 mbbls/d of blended heavy feedstock, 44 mbbls/d of sour SCO and 58 mbbls/d of sweet SCO.

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 Trans Mountain 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 the 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. The Burrard distribution terminal has total export capacity of 40 mbbls/d. 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, 2022 and 2021.

Average Daily Crude Throughput (mbbls/d, except as noted)	Montreal		Sarnia		Edmonton		Commerce City	
	2022	2021	**2022**	2021	**2022**	2021	**2022**	2021
Sweet synthetic	20.2	15.0	25.0	23.4	53.8	59.0	—	—
Sour synthetic	—	—	32.4	33.7	45.2	44.0	8.4	7.5
Diluted bitumen	26.1	25.4	—	—	39.0	34.2	9.5	7.9
Sweet conventional	74.2	78.0	—	1.4	—	—	60.3	51.5
Sour conventional	7.8	4.7	20.5	21.2	—	—	10.8	8.6
Total	128.3	123.1	77.9	79.7	138.0	137.2	89.0	75.5
Utilization (%)	94	90	92	94	95	94	91	77
Equity crude processed(1)	19.2	13.1	46.7	51.5	99.4	102.3	8.4	7.5

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

Refined Petroleum Production Yield Mix (%)	Montreal		Sarnia		Edmonton		Commerce City	
	2022	2021	**2022**	2021	**2022**	2021	**2022**	2021
Gasoline	35	37	45	45	38	43	48	50
Distillates	39	37	40	40	56	52	34	33
Other	26	26	15	15	6	5	18	17

Distribution Terminals and Pipelines

Suncor owns and operates 13 major refined product terminals across Canada (including terminals adjacent to refineries) and three 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.

As at December 31, 2022, Suncor's ownership interests in certain pipelines were as follows:

Pipeline	Ownership	Type	Origin	Destinations
Portland-Montreal Pipeline	100.00%	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, 2022, this network consisted of 1,590 outlets across Canada, of which 781 locations are company-owned locations and 809 are branded dealers. Selected locations along the Trans-Canada Highway are part of Canada's Electric Highway™, the coast-to-coast network of fast-charging electric vehicle stations. 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 4.2 million litres per site in 2022 (2021 –4.2 million litres).

Suncor's Colorado retail network consists of 44 owned or leased Shell ™, Exxon™ or Mobil™ branded outlets. Suncor also has product supply agreements with 108 Shell-branded sites in both Colorado and Wyoming, and with 66 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

Suncor's retail network consists of the following branded outlets supplied with Suncor fuel. These outlets are comprised of Suncor owned or leased locations, as well as third-party sites branded and supplied with branded fuel through Suncor. The number of wholesale sites is shown in the table below.

Locations	As at December 31 **2022**	2021
Retail Service Stations - Canada		
Petro-Canada branded	1,589	1,583
Sunoco branded	1	1
	1,590	1,584
Retail Service Stations - U.S.		
Shell-branded retail service stations - Colorado/Wyoming	143	145
Exxon-branded retail service stations - Colorado	46	57
Mobil-branded retail service stations - Colorado	31	18
	220	220
Wholesale Cardlock Sites - Canada		
Petro-Canada-branded cardlock sites (PETRO-PASS)	323	323

(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

Sales Volumes	**2022** **mbbls/d**	**% Operating Revenues**	2021 mbbls/d	% Operating Revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	107.0		110.2	
Western North America	120.6		115.6	
	227.6	40	225.8	44
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	96.9		94.7	
Western North America	147.7		133.8	
	244.6	51	228.5	43
Other (includes heavy fuel oil, asphalts, petrochemicals, other)				
Eastern North America	55.4		51.3	
Western North America	26.0		22.8	
	81.4	9	74.1	13
	553.6		528.4	

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. Suncor also has the flexibility to import and export refined products to optimize domestic seasonal cycles and to capture incremental margins from market dislocations as they arise.

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 oil and NGL 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

Subsequent to 2022, Suncor completed the sale of its wind and solar assets which included the company's interest in Magrath, Chin Chute, Adelaide and Forty Mile wind farms, as well as development stage renewable power assets.

Following the end of the Power Purchase Agreement, in the third quarter of 2022, Suncor, with its joint venture partner, commenced the decommissioning of the 11 MW Sunbridge power asset in Saskatchewan. The asset is expected to be fully decommissioned in 2023.

Suncor's wind power projects as at December 31, 2022

Wind Power Projects		Ownership Interest (%)	Gross (MW)	Turbines	Completed
Operated by Suncor					
Forty Mile	Maleb, Alberta	100.0	200	45	2022
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

Suncor Employees

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

As at December 31	2022	2021
Oil Sands[1]	10,076	10,423
Exploration and Production	293	296
Refining and Marketing	2,615	2,673
Corporate and Shared Services[2]	3,574	3,530
Total	16,558	16,922

(1) Includes employees related to the Fort Hills and Syncrude 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 25% of the company's employees are covered by collective agreements. The company negotiated collective agreements for Commerce City Refinery, Ottawa Terminal and Portland-Montreal Pipeline in 2022. Negotiations for 11 collective agreements covering 88% of unionized employees will take place in 2023.

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, equal opportunity and discrimination, respectful workplace, 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 that 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 should include its own operations and, where it can influence its third-party business relationships, the operations of others.

Suncor has a Stakeholder Relations Policy that 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 Indigenous Relations Policy that affirms Suncor's desire to work in collaboration with Indigenous Peoples to create shared value. The policy sets the foundation for a consistent approach to the company's relationships with Indigenous 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 Indigenous Peoples and communities to build and maintain long-term and mutually beneficial relationships. The policy makes it clear that Suncor strives for relationships that are based on transparency, mutual respect and trust.

Suncor has an Environment, Health and Safety (EH&S) policy that 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 EHS&SD 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. The EHS&SD Committee reviews and makes recommendations to the Board (and to the Human Resources and Compensation Committee for the purposes of executive incentive plans) regarding the company's safety- and environment-related performance goals and to assess whether such goals have been met. 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 Indigenous 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.

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 Indigenous 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 March 6, 2023, with an effective date of December 31, 2022. Reserves evaluations have not been updated since the effective date and, therefore, do not reflect changes in the company's reserves since that date. The preparation date of the Statement of Reserves Data and Other Oil and Gas Information outlined below is February 2, 2023.

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 is based upon evaluations conducted by GLJ Ltd. (GLJ), contained in its report dated February 17, 2023 (the GLJ Report). GLJ is an independent qualified reserves evaluator 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 performance, pricing, economic conditions, market availability or regulatory requirements. Additional technical information regarding geology, hydrogeology, 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 the 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 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 the Industry Conditions section of this AIF and the Risk Factors section of the company's annual 2022 MD&A, which section is incorporated by reference herein and available on Suncor's SEDAR profile at sedar.com. 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 estimated reserves and associated cash flows 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, low commodity prices could have a material adverse effect on Suncor's reserves; conversely, higher commodity prices may result in higher reserves by making more projects economically viable or extending their economic life.

- 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 Regulations – Climate Change and GHG Emissions 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.

- 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, 2022. 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.

- 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, such as mandatory production curtailments, tax or royalty changes, could create long-term market uncertainty, which could have a material adverse effect on Suncor's reserves.

For additional information on significant risk factors and uncertainties affecting Suncor's reserves, refer to the Risk Factors section of the company's annual 2022 MD&A, which section is incorporated by reference herein and available on Suncor's SEDAR profile at sedar.com.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves[1]

as at December 31, 2022
(forecast prices and costs) [2]

	SCO[3] (mmbbls)		Bitumen (mmbbls)		Light Crude Oil & Medium Crude Oil[4] (mmbbls)		Conventional Natural Gas[6] (bcfe)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing										
Mining	1,373	1,218	799	720	—	—	—	—	2,173	1,938
In Situ	262	217	79	62	—	—	—	—	341	279
E&P Canada	—	—	—	—	94	80	—	—	94	80
Total Canada	1,635	1,436	878	782	94	80	—	—	2,608	2,297
North Sea	—	—	—	—	32	32	2	2	32	32
Total Proved Developed Producing	1,635	1,436	878	782	126	112	2	2	2,640	2,330
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—	—
E&P Canada	—	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—	—	—
North Sea	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	—	—	—	—	—	—	—	—	—	—
Proved Undeveloped										
Mining	273	248	26	23	—	—	—	—	299	271
In Situ	668	539	514	412	—	—	—	—	1,182	951
E&P Canada	—	—	—	—	59	51	—	—	59	51
Total Canada	941	787	540	435	59	51	—	—	1,540	1,273
North Sea	—	—	—	—	1	1	—	—	1	1
Total Proved Undeveloped	941	787	540	435	60	51	—	—	1,541	1,274
Proved										
Mining	1,646	1,467	826	743	—	—	—	—	2,472	2,210
In Situ	930	756	593	474	—	—	—	—	1,523	1,230
E&P Canada	—	—	—	—	153	131	—	—	153	131
Total Canada	2,576	2,223	1,419	1,217	153	131	—	—	4,148	3,571
North Sea	—	—	—	—	33	33	2	2	33	33
Total Proved	2,576	2,223	1,419	1,217	185	163	2	2	4,181	3,604
Probable										
Mining	302	265	383	316	—	—	—	—	685	582
In Situ	1,331	1,020	244	182	—	—	—	—	1,575	1,202
E&P Canada	—	—	—	—	114	85	—	—	114	85
Total Canada	1,633	1,285	626	498	114	85	—	—	2,374	1,868
North Sea	—	—	—	—	11	11	1	1	11	11
Total Probable	1,633	1,285	626	498	125	96	1	1	2,385	1,879
Proved Plus Probable										
Mining	1,948	1,732	1,209	1,059	—	—	—	—	3,157	2,791
In Situ	2,261	1,776	836	656	—	—	—	—	3,098	2,432
E&P Canada	—	—	—	—	267	215	—	—	267	215
Total Canada	4,210	3,508	2,045	1,715	267	215	—	—	6,521	5,439
North Sea	—	—	—	—	43	43	3	3	44	44
Total Proved Plus Probable	4,210	3,508	2,045	1,715	310	259	3	3	6,565	5,483

Please see Notes (1) through (4) and (6) 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, 2022 (forecast prices and costs) [2]

	SCO[3]			Bitumen			Light Crude Oil & 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	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe	mmboe
Mining															
December 31, 2021	1,737	403	2,140	787	461	1,248	—	—	—	—	—	—	2,524	864	3,387
Extensions & Improved Recovery[7]	—	110	110	—	3	3	—	—	—	—	—	—	—	113	113
Technical Revisions[8]	44	(210)	(165)	73	(82)	(9)	—	—	—	—	—	—	117	(291)	(174)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(136)	—	(136)	(34)	—	(34)	—	—	—	—	—	—	(169)	—	(169)
December 31, 2022	1,646	302	1,948	826	383	1,209	—	—	—	—	—	—	2,472	685	3,157
In Situ															
December 31, 2021	990	1,275	2,265	571	336	907	—	—	—	—	—	—	1,561	1,611	3,172
Extensions & Improved Recovery[7]	6	(6)	—	2	(2)	—	—	—	—	—	—	—	8	(8)	—
Technical Revisions[8]	(26)	62	36	52	(90)	(39)	—	—	—	—	—	—	26	(28)	(3)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(40)	—	(40)	(32)	—	(32)	—	—	—	—	—	—	(72)	—	(72)
December 31, 2022	930	1,331	2,261	593	244	836	—	—	—	—	—	—	1,523	1,575	3,098
E&P Canada															
December 31, 2021	—	—	—	—	—	—	113	103	215	—	—	—	113	103	215
Extensions & Improved Recovery[7]	—	—	—	—	—	—	48	14	61	—	—	—	48	14	61
Technical Revisions[8]	—	—	—	—	—	—	6	(4)	1	—	—	—	6	(4)	1
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	2	1	3	—	—	—	2	1	3
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	3	1	4	—	—	—	3	1	4
Production[13]	—	—	—	—	—	—	(19)	—	(19)	—	—	—	(19)	—	(19)
December 31, 2022	—	—	—	—	—	—	153	114	267	—	—	—	153	114	267
Total Canada															
December 31, 2021	2,727	1,678	4,405	1,358	797	2,155	113	103	215	—	—	—	4,197	2,578	6,775
Extensions & Improved Recovery[7]	6	104	110	2	1	3	48	14	61	—	—	—	56	118	174
Technical Revisions[8]	19	(148)	(129)	124	(172)	(48)	6	(4)	1	—	—	—	149	(324)	(176)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	2	1	3	—	—	—	2	1	3
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	3	1	4	—	—	—	3	1	4
Production[13]	(176)	—	(176)	(65)	—	(65)	(19)	—	(19)	—	—	—	(260)	—	(260)
December 31, 2022	2,576	1,633	4,210	1,419	626	2,045	153	114	267	—	—	—	4,148	2,374	6,521

Please see Notes (1) through (13) at the end of the reserves data section for important information about volumes in this table. Suncor's resources in Libya and Syria are classified as contingent resources, and are not disclosed above.

Reconciliation of Gross Reserves[1] *(continued)*

as at December 31, 2022
(forecast prices and costs) [2]

	SCO[3]			Bitumen			Light Crude Oil & 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	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe	mmboe
North Sea															
December 31, 2021	—	—	—	—	—	—	46	16	63	13	6	19	49	17	66
Extensions & Improved Recovery[7]	—	—	—	—	—	—	5	(4)	1	1	(1)	—	5	(4)	1
Technical Revisions[8]	—	—	—	—	—	—	(4)	2	(2)	1	—	1	(4)	2	(2)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	(7)	(3)	(11)	(11)	(4)	(15)	(9)	(4)	(13)
Economic Factors[12]	—	—	—	—	—	—	1	—	1	—	—	—	1	—	1
Production[13]	—	—	—	—	—	—	(9)	—	(9)	(2)	—	(2)	(9)	—	(9)
December 31, 2022	—	—	—	—	—	—	33	11	43	2	1	3	33	11	44
Total															
December 31, 2021	2,727	1,678	4,405	1,358	797	2,155	159	119	278	13	6	19	4,246	2,595	6,841
Extensions & Improved Recovery[7]	6	104	110	2	1	3	53	10	63	1	(1)	—	61	114	176
Technical Revisions[8]	19	(148)	(129)	124	(172)	(48)	2	(2)	(1)	1	—	1	145	(322)	(178)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	2	1	3	—	—	—	2	1	3
Dispositions[11]	—	—	—	—	—	—	(7)	(3)	(11)	(11)	(4)	(15)	(9)	(4)	(13)
Economic Factors[12]	—	—	—	—	—	—	5	1	5	—	—	—	5	1	5
Production[13]	(176)	—	(176)	(65)	—	(65)	(28)	—	(28)	(2)	—	(2)	(269)	—	(269)
December 31, 2022	2,576	1,633	4,210	1,419	626	2,045	185	125	310	2	1	3	4,181	2,385	6,565

Please see Notes (1) through (13) at the end of the reserves data section for important information about volumes in this table. Suncor's resources in Libya and Syria are classified as contingent resources, and are not disclosed above.

Notes to Reserves Data Tables

as at December 31, 2022

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

(2) See the Notes to the 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 oil and medium crude oil for E&P Canada include immaterial quantities of heavy crude oil as follows: proved developed producing of 52 mmbbls, proved of 52 mmbbls, probable of 19 mmbbls and proved plus probable of 71 mmbbls. Net volumes of light crude oil & medium crude oil for E&P Canada include immaterial quantities of heavy crude oil as follows: proved developed producing of 45 mmbbls, proved of 45 mmbbls, probable of 15 mmbbls and proved plus probable of 59 mmbbls.

(5) Light crude oil and medium crude oil technical revisions for E&P Canada include quantities of heavy crude oil as follows: proved of 7 mmbbls, probable of (6) mmbbls and proved plus probable of 0.6 mmbbls.

(6) Conventional natural gas includes immaterial amounts of 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 2022 are primarily a result of additions from Syncrude MLX-E and the West White Rose Project.

(8) Technical revisions include changes in previous estimates resulting from new technical data or revised interpretations. Changes in 2022 are primarily due to new information obtained during the year, including drilling results and ongoing field performance. In 2022, Mining changes are primarily due to mine plan updates at Millennium/North Steepbank and Fort Hills, and risk revisions at Fort Hills. In 2022, In Situ and E&P changes are primarily due to production performance updates.

(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. There were no discoveries in 2022.

(10) Acquisitions are additions to reserves estimates as a result of purchasing interests in oil and gas properties. In 2022, Suncor increased its working interest in White Rose.

(11) Dispositions are reductions in reserves estimates as a result of selling all or a portion of an interest in oil and gas properties. In 2022, Suncor divested its interest in Norway. See the discussion in E&P International – Assets and Operations section above.

(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.

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

Net Present Values of Future Net Revenues Before Income Taxes[1]

as at December 31, 2022
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value[2]
	0%	5%	10%	15%	20%	($/boe)
Proved Developed Producing						
Mining	14,547	29,170	24,822	20,356	17,039	12.81
In Situ	11,594	10,247	9,123	8,213	7,474	32.66
E&P Canada	3,188	3,182	3,077	2,946	2,813	38.59
Total Canada	29,329	42,598	37,023	31,514	27,326	16.11
North Sea	2,050	1,943	1,808	1,676	1,556	56.05
Total Proved Developed Producing	31,380	44,541	38,831	33,191	28,882	16.67
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	—	—	—	—	—	—
E&P Canada	14	13	11	10	9	83.01
Total Canada	14	13	11	10	9	83.01
North Sea	—	—	—	—	—	
Total Proved Developed Non-Producing	14	13	11	10	9	83.01
Proved Undeveloped						
Mining	4,016	3,057	1,955	1,222	758	7.21
In Situ	32,885	18,266	11,067	7,209	4,975	11.64
E&P Canada	2,095	1,627	1,219	886	622	24.02
Total Canada	38,996	22,949	14,241	9,317	6,354	11.19
North Sea	18	15	12	9	7	18.41
Total Proved Undeveloped	39,014	22,964	14,253	9,327	6,362	11.19
Proved						
Mining	18,563	32,226	26,777	21,578	17,796	12.12
In Situ	44,479	28,512	20,191	15,422	12,449	16.41
E&P Canada	5,297	4,821	4,307	3,842	3,445	32.98
Total Canada	68,339	65,560	51,274	40,842	33,690	14.36
North Sea	2,069	1,958	1,820	1,686	1,563	55.31
Total Proved	70,408	67,517	53,095	42,527	35,253	14.73
Probable						
Mining	19,065	9,744	5,824	4,026	3,072	10.01
In Situ	72,756	20,726	8,269	4,427	2,917	6.88
E&P Canada	6,801	4,829	3,521	2,641	2,035	41.49
Total Canada	98,621	35,299	17,614	11,094	8,024	9.43
North Sea	993	789	632	515	430	56.90
Total Probable	99,614	36,088	18,246	11,610	8,455	9.71
Proved Plus Probable						
Mining	37,628	41,970	32,601	25,604	20,869	11.68
In Situ	117,235	49,238	28,460	19,849	15,366	11.70
E&P Canada	12,098	9,650	7,827	6,483	5,480	36.33
Total Canada	166,960	100,859	68,888	51,936	41,714	12.67
North Sea	3,062	2,747	2,452	2,201	1,993	55.71
Total Proved Plus Probable	170,022	103,606	71,340	54,137	43,707	13.01

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, 2022
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	5,924	22,526	19,514	15,977	13,329
In Situ	9,043	7,976	7,079	6,351	5,764
E&P Canada	2,581	2,594	2,509	2,398	2,286
Total Canada	17,548	33,096	29,101	24,727	21,378
North Sea	356	381	373	354	332
Total Proved Developed Producing	17,904	33,477	29,475	25,081	21,710
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	—	—	—	—	—
E&P Canada	11	9	8	8	7
Total Canada	11	9	8	8	7
North Sea	—	—	—	—	—
Total Proved Developed Non-Producing	11	9	8	8	7
Proved Undeveloped					
Mining	2,669	2,163	1,345	795	451
In Situ	25,065	13,701	8,184	5,265	3,591
E&P Canada	1,406	1,093	802	558	363
Total Canada	29,140	16,957	10,331	6,618	4,404
North Sea	11	10	10	9	8
Total Proved Undeveloped	29,151	16,967	10,341	6,627	4,412
Proved					
Mining	8,593	24,689	20,859	16,772	13,779
In Situ	34,108	21,677	15,263	11,616	9,354
E&P Canada	3,998	3,696	3,320	2,964	2,656
Total Canada	46,698	50,062	39,441	31,352	25,789
North Sea	367	391	383	363	340
Total Proved	47,066	50,453	39,824	31,715	26,130
Probable					
Mining	15,395	7,633	4,414	2,983	2,246
In Situ	55,868	15,765	6,304	3,406	2,265
E&P Canada	5,341	3,751	2,703	2,006	1,531
Total Canada	76,604	27,149	13,421	8,396	6,042
North Sea	435	339	264	209	170
Total Probable	77,040	27,488	13,685	8,605	6,212
Proved Plus Probable					
Mining	23,988	32,322	25,272	19,755	16,025
In Situ	89,975	37,442	21,567	15,022	11,619
E&P Canada	9,339	7,447	6,023	4,971	4,187
Total Canada	123,302	77,211	52,862	39,748	31,831
North Sea	803	730	647	572	511
Total Proved Plus Probable	124,105	77,941	53,509	40,320	32,342

See the Notes at the end of the Future Net Revenues Tables.

Total Future Net Revenues[1]

as at December 31, 2022
(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	214,902	23,300	105,510	27,347	44,198	14,547	8,623	5,924
In Situ	34,662	5,497	13,186	3,571	813	11,594	2,551	9,043
E&P Canada	10,395	1,549	2,754	308	2,596	3,188	607	2,581
Total Canada	259,958	30,346	121,449	31,226	47,607	29,329	11,782	17,548
North Sea	3,628	—	1,116	17	445	2,050	1,694	356
Total Proved Developed Producing	263,587	30,346	122,565	31,244	48,052	31,380	13,476	17,904
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—
E&P Canada	20	6	—	—	—	14	4	11
Total Canada	20	6	—	—	—	14	4	11
North Sea	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	20	6	—	—	—	14	4	11
Proved Undeveloped								
Mining	32,801	3,049	19,343	4,450	1,942	4,016	1,347	2,669
In Situ	122,983	22,853	46,706	19,268	1,272	32,885	7,820	25,065
E&P Canada	6,611	984	1,390	1,966	177	2,095	689	1,406
Total Canada	162,396	26,887	67,439	25,684	3,391	38,996	9,856	29,140
North Sea	72	—	11	43	—	18	7	11
Total Proved Undeveloped	162,468	26,887	67,449	25,727	3,391	39,014	9,863	29,151
Proved								
Mining	247,703	26,349	124,853	31,797	46,140	18,563	9,970	8,593
In Situ	157,645	28,351	59,892	22,839	2,085	44,479	10,372	34,108
E&P Canada	17,026	2,539	4,144	2,274	2,773	5,297	1,299	3,998
Total Canada	422,374	57,238	188,889	56,910	50,997	68,339	21,641	46,698
North Sea	3,700	—	1,126	60	445	2,069	1,702	367
Total Proved	426,074	57,238	190,015	56,971	51,442	70,408	23,343	47,066
Probable								
Mining	80,029	12,009	35,299	8,578	5,079	19,065	3,669	15,395
In Situ	250,515	54,331	86,804	34,962	1,663	72,756	16,888	55,868
E&P Canada	13,007	3,591	1,691	702	221	6,801	1,460	5,341
Total Canada	343,550	69,931	123,794	44,242	6,963	98,621	22,017	76,604
North Sea	1,312	—	287	5	27	993	558	435
Total Probable	344,863	69,931	124,081	44,247	6,990	99,614	22,574	77,040
Proved Plus Probable								
Mining	327,732	38,358	160,152	40,375	51,219	37,628	13,639	23,988
In Situ	408,160	82,681	146,696	57,801	3,748	117,235	27,259	89,975
E&P Canada	30,033	6,130	5,835	2,976	2,994	12,098	2,759	9,339
Total Canada	765,925	127,169	312,683	101,152	57,961	166,960	43,658	123,302
North Sea	5,013	—	1,413	66	472	3,062	2,259	803
Total Proved Plus Probable	770,937	127,169	314,096	101,218	58,433	170,022	45,917	124,105

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

Future Net Revenues by Product Type[1]

as at December 31, 2022
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	Unit Value $/boe[2]
Proved Developed Producing		
SCO	25,478	17.75
Bitumen	8,467	10.83
Light Crude Oil & Medium Crude Oil	3,033	45.42
Heavy Crude Oil	1,836	40.87
Conventional Natural Gas[3]	17	56.13
Total Proved Developed Producing	38,831	16.67
Proved		
SCO	33,130	14.90
Bitumen	13,838	11.37
Light Crude Oil & Medium Crude Oil	4,413	37.24
Heavy Crude Oil	1,697	37.96
Conventional Natural Gas[3]	18	55.30
Total Proved	53,095	14.73
Proved Plus Probable		
SCO	45,554	12.98
Bitumen	15,507	9.04
Light Crude Oil & Medium Crude Oil	7,815	39.14
Heavy Crude Oil	2,436	41.10
Conventional Natural Gas[3]	29	55.75
Total Proved Plus Probable	71,340	13.01

(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 some 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. The upgrader operating and sustaining capital costs are pro-rated to the estimated upgrader capacity available for In Situ volumes and considered in the estimation. For total proved plus probable reserves, approximately 61% of Firebag bitumen production is expected to be upgraded to SCO by 2034 and 100% thereafter.

Power sale revenues and the natural gas fuel expense associated with excess electricity 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 Report, were derived using averages of forecasts developed by GLJ (dated January 1, 2023), Sproule Associates Limited (dated December 31, 2022) and McDaniel & Associates Consultants Ltd. (dated January 1, 2023), all of whom are independent qualified reserves evaluators. 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 nil in 2023, 2.3% in 2024 and 2.0% thereafter.

Carbon cost compliance for Canadian reserves are based on the federal Greenhouse Gas Pollution Pricing Act which escalates from $65/tonne in 2023 to $170/tonne in 2030. For the Oil Sands projects, the compliance cost determination incorporates the Alberta Government's December 2022 amendment to TIER.

Prices Impacting Reserves Tables

Forecast	Brent North Sea[1]	WTI Cushing Oklahoma[2]	WCS Hardisty Alberta[3]	Light Sweet Edmonton Alberta[4]	Pentanes Plus Edmonton Alberta[5]	AECO Gas[6]	National Balancing Point North Sea[7]
Year	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu
2022[8]	101.20	94.25	75.95	120.10	122.05	4.85	32.15
2023	84.67	80.33	76.54	103.77	106.22	4.23	45.37
2024	82.69	78.50	77.75	97.74	101.35	4.40	35.75
2025	81.03	76.95	77.54	95.27	98.94	4.21	26.05
2026	81.39	77.61	80.07	95.58	100.19	4.27	22.38
2027	82.65	79.16	81.89	97.07	101.74	4.34	21.23
2028	84.29	80.75	84.02	99.01	103.78	4.43	21.66
2029	85.98	82.36	85.73	100.99	105.85	4.51	22.09
2030	87.70	84.01	87.44	103.01	107.97	4.60	22.53
2031	89.46	85.69	89.20	105.07	110.13	4.69	22.98
2032	91.25	87.40	91.11	106.69	112.33	4.79	23.44
2033	93.07	89.15	92.93	108.83	114.58	4.89	23.91
2034	94.93	90.93	94.79	111.00	116.87	4.98	24.39
2035	96.83	92.75	96.68	113.22	119.21	5.08	24.88
2036	98.77	94.60	98.62	115.49	121.59	5.18	25.38
2037	100.75	96.50	100.59	117.80	124.03	5.29	25.89
2038+	+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 North Sea reserves.

(2) Price used when determining portions of bitumen reserves presented as In Situ and Mining reserves that are sold at the U.S. Gulf Coast, as well as for determining portions of bitumen pricing for royalty calculation purposes.

(3) Price used when determining portions of bitumen reserves presented as In Situ and Mining reserves that are sold in Canada, as well as for determining bitumen pricing for royalty calculation purposes.

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

(5) 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.

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

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

(8) Prices for 2022 reflect the company's historical weighted average prices.

Forecast Foreign Exchange Rates Impacting Forecast Prices

Forecast	US$/Cdn$ Exchange Rate	Cdn$/€ Exchange Rate	Cdn$/£ Exchange Rate
Year			
2023	0.745	1.454	1.615
2024	0.765	1.427	1.612
2025	0.768	1.443	1.640
2026	0.772	1.445	1.652
2027	0.775	1.439	1.656
2028+	0.775	1.439	1.656

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 a business area or legal entity level 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 2022 audited Consolidated Financial Statements and the annual 2022 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, 2022
(forecast prices and costs)

($ millions)	2023	2024	2025	2026	2027	Remainder	Total	Discounted at 10%
Proved								
Mining	2,739	2,918	2,571	2,297	2,430	18,844	31,797	18,350
In Situ	804	1,224	922	588	872	18,430	22,839	8,934
E&P Canada	451	484	394	197	122	626	2,274	1,699
Total Canada	3,994	4,625	3,887	3,082	3,423	37,899	56,910	28,983
North Sea	47	3	2	2	1	5	60	54
Total Proved	4,041	4,628	3,889	3,084	3,425	37,904	56,971	29,036
Proved Plus Probable								
Mining	2,908	3,129	2,802	2,625	2,759	26,152	40,375	20,991
In Situ	829	881	772	814	722	53,784	57,801	10,205
E&P Canada	524	610	530	333	208	771	2,976	2,198
Total Canada	4,260	4,621	4,104	3,772	3,688	80,707	101,152	33,394
North Sea	50	3	2	2	1	8	66	57
Total Proved Plus Probable	4,310	4,623	4,106	3,775	3,690	80,714	101,218	33,451

(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 2023 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 autonomous haulage systems.
- For both Firebag and MacKay River operations within In Situ, the drilling of new well pairs, the design and construction of new well pads, and facility maintenance that are expected to maintain existing production levels in future years.
- For E&P Canada, capital investments related to the West White Rose Project, and development drilling at Hebron and Hibernia.
- For E&P International, capital investments related to the Rosebank development and development drilling at Buzzard until the assets are divested.

Future development costs 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, if needed, 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 Report. 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 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 and the possible future use of the site.

As at December 31, 2022, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs for its upstream assets to be approximately $22.1 billion (discounted at 10%, approximately $4.1 billion). In 2022, the company recognized an increased liability primarily due to water treatment costs for mining assets. The Refining and Marketing liabilities are estimated at $0.3 billion, undiscounted and uninflated. Abandonment and reclamation cost estimates are limited to current disturbances at December 31, 2022 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, 2022. Suncor estimates that it will incur $1.2 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2023 – $0.4 billion, 2024 – $0.4 billion, 2025 – $0.4 billion), more than 86% 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 for Suncor's Oil Sands segment include costs related to the reclamation of disturbed land from oil sands mining activities, future mining disturbances, the treatment of oil sands tailings, water treatment, the decommissioning of oil sands processing facilities and well pads, existing and future reserve wells and associated service wells, disturbed lease sites, and future lease site disturbances. Abandonment and reclamation cost estimates included in the net present values of the company's proved and probable reserves for Suncor's E&P operations are on a life-of-field basis, accounting for abandonment and reclamation of existing and estimated future development items. Abandonment liabilities include offshore equipment and well abandonments. Offshore equipment includes topsides or processing facilities; platforms, FPSOs or GBSs; gathering systems; and other subsea equipment such as templates. Approximately $58.4 billion (inflated and undiscounted) has been deducted as abandonment and reclamation costs in estimating the future net revenues from proved plus probable reserves, including $55.0 billion related to the company's oil sands upgraders, extraction facilities, tailings ponds, subsurface wells and central processing facilities.

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)

	2020		2021		2022	
	First Attributed	Total as at December 31, 2020	First Attributed	Total as at December 31, 2021	**First Attributed**	**Total as at December 31, 2022**
SCO (mmbbls)						
Mining	297	297	—	295	**—**	**273**
In Situ	—	746	2	715	**6**	**668**
Total SCO	297	1,042	2	1,010	**6**	**941**
Bitumen (mmbbls)						
Mining	—	—	—	—	**—**	**26**
In Situ	—	523	1	478	**2**	**514**
Total bitumen	—	523	1	478	**2**	**540**
Light crude oil & medium crude oil (mmbbls)						
E&P Canada	4	18	—	13	**46**	**59**
North Sea	1	8	1	7	**1**	**1**
Total light crude oil & medium crude oil	6	25	1	20	**47**	**60**
Heavy crude oil (mmbbls)						
E&P Canada	—	15	—	2	**—**	**—**
North Sea	—	—	—	—	**—**	**—**
Total heavy crude oil	—	15	—	2	**—**	**—**
Conventional natural gas (bcfe)						
E&P Canada	—	—	—	—	**—**	**—**
North Sea[2]	—	11	—	11	**—**	**—**
Total conventional natural gas	—	11	—	11	**—**	**—**
Total (mmboe)	302	1,608	3	1,513	**55**	**1,541**

(1) Figures may not add due to rounding.

(2) Includes immaterial amounts of NGLs.

Gross Probable Undeveloped Reserves [1]

(forecast prices and costs)

	2020		2021		2022	
	First Attributed	Total as at December 31, 2020	First Attributed	Total as at December 31, 2021	**First Attributed**	**Total as at December 31, 2022**
SCO (mmbbls)						
Mining	—	23	—	23	**110**	**133**
In Situ	116	1,195	—	1,185	**—**	**1,249**
Total SCO	116	1,218	—	1,208	**110**	**1,382**
Bitumen (mmbbls)						
Mining	—	—	—	—	**3**	**3**
In Situ	24	289	—	283	**—**	**175**
Total bitumen	24	289	—	283	**3**	**178**
Light crude oil & medium crude oil (mmbbls)						
E&P Canada	23	55	8	60	**15**	**76**
North Sea	—	3	—	3	**—**	**1**
Total light crude oil & medium crude oil	24	58	8	63	**15**	**77**
Heavy crude oil (mmbbls)						
E&P Canada	—	8	—	2	**—**	**—**
North Sea	—	—	—	—	**—**	**—**
Total heavy crude oil	—	8	—	2	**—**	**—**
Conventional natural gas (bcfe)						
E&P Canada	—	—	—	—	**—**	**—**
North Sea[2]	—	3	—	4	**—**	**—**
Total conventional natural gas	—	3	—	4	**—**	**—**
Total (mmboe)	163	1,573	8	1,556	**129**	**1,638**

(1) Figures may not add due to rounding.

(2) Includes immaterial amounts of NGLs.

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. Suncor plans to proceed with the 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.

In Situ

Undeveloped In Situ reserves, which constitute approximately 77% of Suncor's gross proved undeveloped reserves and 87% of Suncor's gross probable undeveloped reserves have been assigned to reserves areas that 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. 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 new pads and, upon approval, commences development of the reserves and wells surrounding the declining areas. This entails drilling well pairs and constructing sustaining pads and may take up to several years. Management forecasts future proved undeveloped and probable undeveloped reserves development activity. These 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.

Mining

Undeveloped Mining reserves constitute approximately 19% of Suncor's gross proved undeveloped reserves, and 8% of Suncor's gross probable undeveloped reserves and relate to the Syncrude MLX West and East mining areas, which received regulatory approval in 2019 and 2020, respectively. Development of MLX-W consists of typical mine development activities; construction activities were restarted in 2021 and continued through 2022. MLX-W reserves will remain as undeveloped until its major components, such as a bridge, are completed. Development of MLX-E consists of typical mine development activities in addition to relocation of infrastructure that currently occupies the lease footprint and construction of a production haul road from the lease; project engineering commenced in 2022. MLX-E reserves will remain as undeveloped until its major components, such as infrastructure relocation and the production haul road, are completed. Both projects will utilize existing ore processing and extraction facilities at Syncrude's Mildred Lake operation and are expected to sustain bitumen production levels at Mildred Lake after resource depletion at the North Mine.

E&P

Undeveloped conventional reserves (light crude oil and medium crude oil, heavy crude oil and natural gas) constitute approximately 4% of Suncor's gross proved undeveloped reserves and approximately 5% of Suncor's gross probable undeveloped reserves and relate to the company's offshore E&P assets, mainly associated with future drilling at Hebron, Hibernia and White Rose. 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.

Properties with no Attributed Reserves

The following table shows a summary of properties to which no reserves are attributed as at December 31, 2022. 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	2,040,041	774,873
Libya	3,117,800	1,422,900
Syria	345,194	345,194
U.K.	32,750	13,106
Total	5,535,785	2,556,073

Suncor's properties with no attributed reserves range from 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 appraisal or even 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. For additional information on risks and uncertainties, refer to the Risk Factors section of Suncor's annual 2022 MD&A, which section is incorporated by reference herein and available on the company's SEDAR profile at sedar.com.

In 2023, Suncor's rights to 115,708 net hectares in Canada are scheduled to expire. The lands expiring in 2023 include approximately 12,826 net hectares in In Situ and 23,040 net hectares in Mining. Substantial portions of expiring lands may have their tenure continued beyond 2023 through the conduct of work programs and/or the payment of prescribed fees to the mineral rights owner.

Work Commitments

Suncor's properties in Libya have no attributed reserves. The practice of governments requiring companies to pledge to carry out work commitments in exchange for the right to carry out exploration and development activities is common in Libya. Suncor has work commitments primarily for conducting seismic programs and drilling exploration wells. As at December 31, 2022, Suncor estimates that the value of the work commitment associated with its properties with no attributed reserves was US$359 million. Due to the political unrest in Libya, it is uncertain when the work commitments will be incurred.

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, 2022.

	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]	471.0	471.0	17.0	17.0	—	—	—	—
Newfoundland and Labrador	76.0	18.6	26.0	11.4	—	—	—	—
Offshore U.K.	26.0	7.8	8.0	2.4	—	—	—	—
Other International[5]	—	—	422.0	212.6	—	—	6.0	6.0
Total	573.0	497.4	473.0	243.4	—	—	6.0	6.0

(1) Alberta oil wells and Other International oil and gas wells are onshore whereas Newfoundland and Labrador and Offshore U.K. 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 multilateral 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. As 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 exploration and development activities for the year ended December 31, 2022.

($ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Total
Canada – Mining and In Situ	38	—	—	3,633	3,671
Canada – E&P Canada	4	—	—	448	452
Total Canada	**42**	**—**	**—**	**4,081**	**4,123**
North Sea	50	—	—	100	150
Other international	6	—	—	—	6
Total	**98**	**—**	**—**	**4,181**	**4,279**

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, 2022.

	Exploratory Wells[1]		Development Wells	
Total Number of Wells Completed	Gross	Net	Gross	Net
Canada – Oil Sands				
Oil	—	—	36.0	36.0
Service[2]	—	—	33.0	33.0
Stratigraphic test[3]	41.0	22.0	683.0	442.6
Total	41.0	22.0	752.0	511.6
Canada – E&P Canada				
Oil	—	—	2.0	0.4
Dry hole	—	—	—	—
Natural gas	—	—	—	—
Service[2]	—	—	1.0	0.2
Stratigraphic test	—	—	—	—
Total	—	—	3.0	0.6
Total Canada				
Oil	—	—	38.0	36.4
Dry hole	—	—	—	—
Natural gas	—	—	—	—
Service[2]	—	—	34.0	33.2
Stratigraphic test	41.0	22.0	683.0	442.6
Total	41.0	22.0	755.0	512.2
North Sea				
Oil	—	—	3.0	0.7
Dry hole	—	—	—	—
Service[2]	—	—	1.0	0.2
Stratigraphic test	—	—	—	—
Total	—	—	4.0	0.9

(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 2022 included:

- For Mining, at Oil Sands Base, development activities included asset sustainment activities related to the company's planned maintenance program, the continued development of tailings infrastructure and continued construction of a new cogeneration facility. At Fort Hills, development activities focused on construction of tailings infrastructure and mine advancement activities. At Syncrude, development activities included asset sustainment expenditures, scheduled turnaround, planned maintenance activities and the ongoing development of MLX-W.
- For In Situ, the drilling of new well pairs, infill and sidetracked wells at Firebag and MacKay River that are expected to assist in maintaining production levels in future years. Also included are stratigraphic test well and observation well drilling programs.
- For E&P Canada, spending on the Terra Nova ALE Project, development work at the West White Rose Project and drilling activities at Hebron.

- For E&P International, work on the Norwegian Fenja Project, which was subsequently sold in the third quarter of 2022.

For significant exploration and development activities expected to occur in 2023 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]

2022	Q1	Q2	Q3	Q4	Year Ended
Canada - Oil Sands					
Upgraded product (SCO and diesel) production (mbbls/d)					
Oil Sands operations	333.8	294.0	268.8	316.5	303.1
Syncrude	181.5	189.0	136.3	201.0	176.9
Total upgraded production	515.3	483.0	405.1	517.5	480.0
Non-upgraded bitumen production (mbbls/d)					
Oil Sands operations	82.9	71.1	145.1	102.0	100.4
Fort Hills	87.5	87.4	95.8	68.6	84.8
Total Oil Sands non-upgraded bitumen production	170.4	158.5	240.9	170.6	185.2
Total production (mbbls/d)	**685.7**	**641.5**	**646.0**	**688.1**	**665.2**
Netbacks[3][4]					
Non-upgraded bitumen ($/bbl)					
Average price realized[2]	96.49	113.41	79.60	54.52	84.63
Royalties	(15.17)	(19.71)	(11.41)	(10.37)	(13.81)
Operating costs	(21.37)	(22.38)	(16.37)	(22.55)	(20.27)
Netback	59.95	71.32	51.82	21.60	50.55
Upgraded - net SCO and diesel ($/bbl)					
Average price realized[2]	114.37	137.17	119.27	105.38	118.88
Royalties	(16.60)	(26.57)	(15.20)	(10.66)	(17.27)
Operating costs	(34.63)	(35.81)	(42.94)	(37.71)	(37.55)
Netback	63.14	74.79	61.13	57.01	64.06
Average Oil Sands segment ($/bbl)					
Average price realized[2]	110.27	131.28	105.16	92.33	109.57
Royalties	(16.28)	(24.87)	(13.85)	(10.59)	(16.33)
Operating costs	(31.59)	(32.48)	(33.49)	(33.82)	(32.85)
Netback	62.40	73.93	57.82	47.92	60.39
Exploration and Production - light crude oil & medium crude oil					
Exploration and Production Canada (mbbls/d)	51.2	52.9	47.5	49.1	50.2
Exploration and Production North Sea (mboe/d)	29.2	25.8	30.6	25.9	27.8
Total production volumes (mboe/d)	**80.4**	**78.7**	**78.1**	**75.0**	**78.0**
Netbacks[3][4]					
Canada - light crude oil & medium crude oil ($/bbl)					
Average price realized[2]	122.13	140.24	130.37	112.93	128.07
Royalties	(19.47)	(19.58)	(17.52)	(15.70)	(18.25)
Operating costs	(13.15)	(13.36)	(13.85)	(20.17)	(14.69)
Netback	89.51	107.30	99.00	77.06	95.13
North Sea - light crude oil & medium crude oil ($/boe)[5]					
Average price realized[2]	113.60	127.84	137.29	128.86	126.61
Operating costs	(8.79)	(10.96)	(9.95)	(9.16)	(9.66)
Netback[4]	104.81	116.88	127.34	119.70	116.95

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

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

(3) Netbacks are based on sales volumes.

(4) Netback contain non-GAAP financial measures. See the Advisory – Forward-Looking Information and Non-GAAP Financial Measures section of this AIF.

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

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, 2022.

	SCO	Bitumen	Light Crude Oil & Medium Crude Oil
	mbbls/d	mbbls/d	mboe/d
Mining – Suncor	203.7	—	—
Mining – Syncrude	176.9	—	—
Mining – Fort Hills	—	84.8	—
Firebag	99.4	68.0	—
MacKay River	—	32.4	—
Buzzard	—	—	20.9
Hibernia	—	—	15.1
White Rose	—	—	6.1
Terra Nova	—	—	—
Hebron[2]	—	—	29.0

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

(2) The majority of volumes shown for Hebron are heavy crude oil volumes.

Production Estimates

The table below outlines the production estimates for 2023 that are included in the estimates of proved reserves and probable reserves as at December 31, 2022.

	SCO (mbbls/d)[1]		Bitumen (mbbls/d)[1]		Light Crude Oil & Medium Crude Oil (mbbls/d)[1]		Conventional Natural Gas (mmcfe/d)[1][2]		Total (mboe/d)[1]	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
Proved	445	405	187	159	56	51	—	—	688	615
Probable	32	28	16	12	4	3	—	—	51	43
Proved Plus Probable	476	433	203	171	60	55	—	—	739	658
North Sea[3]										
Proved	—	—	—	—	19	19	3	3	19	19
Probable	—	—	—	—	2	2	1	1	2	2
Proved Plus Probable	—	—	—	—	21	21	4	4	21	21
Total[1][2]										
Proved	445	405	187	159	75	70	3	3	707	634
Probable	32	28	16	12	6	5	1	1	53	45
Proved Plus Probable	476	433	203	171	80	75	4	4	761	679

(1) Figures may not add due to rounding.

(2) Conventional natural gas includes immaterial amounts of NGLs.

(3) Subsequent to 2022, the company reached an agreement for the sale of its U.K. E&P portfolio, which is expected to close in mid-2023.

The following properties each account for approximately 20% or more of total estimated production for 2023.

Proved

- From Millennium and North Steepbank: 184 mbbls/d of SCO, which represents approximately 26% of total estimated production for 2023.
- From Firebag: 173 mbbls/d of SCO and bitumen (103 mbbls/d and 70 mbbls/d, respectively), which represents approximately 24% of total estimated production for 2023.
- From Syncrude: 167 mbbls/d of SCO and bitumen (159 mbbls/d and 8 mbbls/d, respectively), which represents approximately 24% of total estimated production for 2023.

Proved Plus Probable

- From Millennium and North Steepbank: 196 mbbls/d of SCO, which represents approximately 26% of total estimated production for 2023.
- From Firebag: 186 mbbls/d of SCO and bitumen (107 mbbls/d and 79 mbbls/d, respectively), which represents approximately 25% of total estimated production for 2023.
- From Syncrude: 181 mbbls/d of SCO and bitumen (173 mbbls/d and 8 mbbls/d, respectively), which represents approximately 24% of total estimated production for 2023.

None of the company's light and medium crude oil production associated with its E&P Canada and Offshore U.K. assets accounts for 20% or more of the total estimated production for 2023.

Forward Contracts

Suncor may use financial derivatives to manage its exposure to fluctuations in commodity prices. A description of Suncor's use of such instruments is provided in the 2022 audited Consolidated Financial Statements and related annual 2022 MD&A.

Tax Horizon

In 2022, Suncor was subject to cash tax in the majority of the jurisdictions in which it generates earnings, including earnings related to its Canadian, U.S. and U.K. production. Based on projected future net earnings, Suncor is expected to be cash taxable on the majority of its earnings in 2023.

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 heavy crude oil (in either case, to a maximum of 25 years), the exporter is required to obtain an export licence from the Canada Energy Regulator (CER). 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 CER approving such export.

Under the Canada-United States-Mexico Agreement (CUSMA), free flow of oil exports between Canada, Mexico and the United States is allowed and requires the parties to treat imported goods no less favourably than domestic goods. Canada maintains tariff-free access to the U.S. and Mexican markets.

CUSMA restricts the parties from adopting or maintaining export and import price requirements, except under the countervailing and anti-dumping duty measures set out in CUSMA, and from requiring, as a condition for importation, that the persons of another party establish a contractual or other relationship with distributors in its territory.

CUSMA contains a "non-market economy" clause that requires parties to notify the other parties three months before entering into free trade talks with a non-market economy. A "non-market economy" may include China or other potential importers of Canadian oil and gas exports. The "non-market economy" clause states that if one party enters into a free trade agreement with a non-market country, the other parties may terminate CUSMA on six months' notice. To date, none of the parties to CUSMA have entered into a free trade agreement with a non-market economy.

Canada and the United States have also entered into an energy-specific side letter which, among other things, mandates the countries to ensure that measures governing access to or use of energy infrastructure, including pipeline networks, are neither unduly discriminatory nor unduly preferential. The energy side letter also encourages Canada and the United States to ensure that the implementation of energy regulatory measures is orderly and equitable, and avoids disruption of contractual relationships to the maximum extent practicable.

On January 25, 2021, U.S. President Joe Biden signed the "Executive Order on Ensuring the Future is Made in All of America by All of America's Workers." The order states that "the United States Government should, consistent with applicable law, use terms and conditions of Federal financial assistance awards and Federal procurements to maximize the use of goods, products, and materials produced in, and services offered in, the United States." Waivers from the order are provided for in certain circumstances. The order applies to all U.S. government procurement and supports the acquisition of all manner of goods, products and materials produced in the United States, with a particular focus on steel, iron and manufactured goods. While discussions between Canada and the United States about the full implications of the order remain outstanding, to the extent the United States government procures oil and gas products or provides financial assistance to U.S. oil and gas producers, the order indicates that the

United States will favour domestic production over foreign (including Canadian) producers and products, subject to applicable law.

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 impacts of the COVID-19 pandemic, 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 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.

For a description 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 2022 was 15% for active business income, including resource income. The average provincial income tax rate for Suncor in 2022 was approximately 9.16%, resulting in a total Canadian income tax rate of approximately 24.16%.

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 1.6%, resulting in a total U.S. income tax rate of approximately 22.6%.

Operations in the U.K. are subject to a tax rate of approximately 50% for 2022, made up of the corporate income tax rate, the supplemental charge, and the Energy (Oil and Gas) Profits Levy. The levy applicable to 2022 oil and gas profits in the U.K. is 25% and was enacted on May 26, 2022. In the fourth quarter of 2022, the levy was increased by an additional 10% effective January 1, 2023. Prior to the sale of the Norway assets, operations in the country were subject to a tax rate of 78%.

Amounts presented in Suncor's 2022 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 the 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, including the ones in which Suncor has operations, 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, production sharing contracts 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 Regulations

The company is subject to environmental regulations 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 products and the byproducts associated with the production thereof, which apply to Suncor and similar activities conducted by other organizations. Applicable regulatory regimes require Suncor to obtain operating licences and permits in order to construct and operate, and impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, refining, as well as electricity generation, transitional energy activities, 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 new laws and amendments to existing 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 regulators that oversee energy development for comment by stakeholders, including industry. These statutes, regulations and frameworks relate to issues such as tailings management, water management, biodiversity, air emissions and land use. The company is committed to working with the appropriate government agencies as new policies are developed, and to comply with all existing and new statutes, regulations and frameworks that apply to the company's operations.

In general, the impact of future environmental laws and regulations on the company remains uncertain. It is not possible to predict the nature of any future legislative requirements or the impact that these 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, installing new emissions abatement equipment, treating fluid tailings, investing in renewable and low-carbon forms of energy, such as combined cycle co-generation, biofuels and hydrogen, undertaking land reclamation activities, investing in environmentally focused research and development, and working to advance 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 and GHG Emissions

Suncor operates in many jurisdictions that regulate, or have proposed to regulate, GHG emissions. Suncor is committed to complying with existing regulations and will continue to constructively engage the appropriate governmental bodies in dialogue to harmonize regulations focused on achieving reduction goals and sustainable resource development across jurisdictions where Suncor owns and/or operates assets.

The rate and pace of change of consumer behaviour, such as the adoption of zero-emission vehicles (ZEVs) or increased use of public transit or active transportation, is not certain. The demand for low-

carbon transportation options is expected to reduce the demand for gasoline and diesel and increase the demand for renewable liquid fuels and electric vehicle charging. As part of its ongoing business planning, Suncor estimates future costs associated with GHG emissions in its operations and in the evaluation of future projects. These estimates use the company's outlook for the carbon price under current and pending GHG regulations which are used in conjunction with other tools to test the company's business strategy against a range of policy designs. As of January 1, 2023, Suncor applies a carbon price of $65 per tonne of CO_2e, which will increase according to the recent federal government announcement described in the Industry Conditions – Climate Change and GHG Emissions – Canadian Federal GHG and Fuel Regulations – Under Development section of this AIF below. The company expects that GHG emissions regulation will continue to evolve with a carbon price that considers environmental, energy security, social and economic objectives.

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. Canada is a signatory to the agreement and Suncor supports the goals articulated in the Paris Agreement.

Canadian Federal GHG and Fuel 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 give effect to the PCF, in 2018 the federal government introduced the *Greenhouse Gas Pollution Pricing Act* (GGPPA). The GGPPA is 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: (i) an economy-wide consumer carbon levy on the use and combustion of fossil fuels; and (ii) an Output-Based Pricing System (OBPS) applied to heavy industrial sectors that face international competition. The GGPPA's current application provincially is discussed below.

On March 25, 2021, in response to court challenges by the provinces of Alberta, Saskatchewan and Ontario regarding the federal government's authority to regulate carbon pricing, the Supreme Court of Canada concluded that the GGPPA is constitutional, and the federal government has a right to impose national requirements for carbon pricing regulations.

Under the GGPPA, the federal government requires all provinces and territories to have a carbon price, which started at $20 per tonne of CO2e in 2019 and has been rising by $10 per year to $50 per tonne of CO2e in 2022. Building upon the PCF, the federal government announced its strengthened climate plan titled "A Healthy Environment and a Healthy Economy" in December 2020. Under the strengthened climate plan, the federal government proposed to increase the carbon price applied to both the GGPPA and the OBPS by $15 per tonne of CO2e per year starting in 2023, rising to $170 per tonne of CO2e in 2030. On August 5, 2021, the federal government published its update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030. The update and supporting information confirmed: (i) Canada's annual national minimum carbon price increase of $15 per tonne of CO2e per year starting in 2023; (ii) minimum criteria for recognized provincial and territorial carbon pollution pricing systems; and (iii) provinces and territories that have carbon pricing systems meeting the minimum criteria, as well as an explanation of the tests used for assessments. The federal carbon pricing benchmark criteria to applicable industrial GHG emissions from 2023-2030 was also updated and the new expectations for increasing stringency were applied to provincial and territorial carbon pricing systems. Provinces and territories have the ability to customize their carbon pricing systems to maintain industrial competitiveness and achieve lowest cost to businesses and consumers.

Jurisdictions can implement: (i) an explicit price-based system (such as the carbon tax adopted by British Columbia), (ii) the carbon levy and performance-based emissions system (adopted in Alberta), or (iii) a

cap and trade system (adopted in Quebec). Within these programs, provinces have discretion to manage the competitiveness of their energy-intensive trade exposed industries. The provincial carbon pricing initiatives applied in Alberta, British Columbia, Quebec, Ontario, and Newfoundland and Labrador and their impact on Suncor are described in the Provincial GHG and Fuel Regulations section below.

Under the federal *Impact Assessment Act*, the Strategic Assessment of Climate Change (SACC) sets new requirements for GHG emissions reporting and planning for any projects governed under the *Impact Assessment Act*, including a requirement to provide a credible plan for relevant projects to deliver net-zero GHG emissions by 2050.

Supporting the above, the federal Renewable Fuels Regulations (RFR) implemented in 2010 under the Canadian Environmental Protection Act, 1999 (CEPA) sets minimum renewable fuel content requirements in gasoline and diesel fuel sold to Canadian consumers. The regulations include provisions that govern the creation of compliance units, allow trading of these units among participants and require reporting to ensure compliance. In addition to the federal RFR, the provinces of Alberta, British Columbia, Manitoba, Ontario, Quebec and Saskatchewan have renewable fuel mandates equal to or greater than the current federal RFR.

In addition to the GGPPA imposing an economy-wide consumer carbon levy on the use and combustion of fossil fuels, the *Clean Fuel Regulation* (CFR) was enacted by the federal government under CEPA, replacing the RFR, which the government estimates will achieve annual reductions of at least 26.6 Mt of CO_2e emissions by 2030. The CFR Gazette II was released on July 6, 2022. Effective July 1, 2023, the CFR requires reductions in the carbon intensity of gasoline and diesel fuels supplied into Canada. Credits for CFR are generated for blending renewable fuels, reducing GHGs at fossil fuel facilities, facilitating fuel switching in transportation or purchasing CFR compliance credits annually. Additionally, there was an inclusion of conditions that credits cannot be obtained from products exported from Canada. Suncor is in the process of implementing CFR requirements to ensure compliance.

Pursuant to the Paris Agreement, the Government of Canada set a new goal to reduce GHG emissions economy-wide from 30% to 40%-45% below 2005 levels by 2030. The federal government has also passed the *Canadian Net-Zero Emissions Accountability Act*, which enshrines in legislation the legal requirement for the federal government to set national GHG emission reduction targets on a rolling five-year basis necessary to achieve net-zero emissions by 2050. This includes requirements to prepare plans and issue progress and assessment reports to ensure accountability.

Consistent with the *Canadian Net-Zero Emissions Accountability Act*, Prime Minister Trudeau announced on November, 1, 2021, at the COP 26 climate conference that Canada is the first major oil-producing country moving to capping and reducing emissions from the oil and gas sector by setting five-year targets to achieve net zero by 2050.

Under Development

On March 16, 2022, Environment and Climate Change Canada (ECCC) released a discussion paper “A Clean Electricity Standard (CES) in Support of a Net-Zero Electricity Sector”. The CES is designed to be the regulatory framework to achieve a net zero electricity system in Canada by 2035. This proposed policy creates risk to carbon pricing programs that provide GHG credits for electricity. It is unclear at this point if this is a risk or opportunity for Suncor electricity generation. Consultations amongst stakeholders are ongoing and Gazette I is expected to be released in 2023.

On March 29, 2022, the federal government announced the release of the *2030 Emissions Reduction Plan: Canada's Next Steps for Clean Air and a Strong Economy*. The plan is a sector-by-sector approach for Canada to reach its climate target of cutting GHG emissions by 40%-45% below 2005 levels by 2030 and contains a goal of achieving net-zero GHG emissions by 2050. At that time, the projected contribution from the oil and gas sector for GHG emissions reduction was 31% from 2005 levels, or 42% from a 2019 baseline. As a follow-up to the 2030 Emissions Reduction Plan, on July 18, 2022, the Government of Canada released a discussion paper document titled “Options to Cap and Cut Oil and Gas Sector Greenhouse Gas Emissions to Achieve 2030 Goals and Net-Zero by 2050”. This document proposes two options for the oil and gas sector to reduce GHG emissions to a proposed government set 110 Mt target in 2030. Option 1 consists of a new cap-and-trade system regulated under CEPA, and Option 2 is a

modification of the current carbon pricing approach under GGPPA. The specific regulatory mechanism of this GHG emission reduction target has not been determined as government consultations are ongoing.

To incentivize decarbonization investment, the federal government is developing an investment tax credit (ITC) for capital invested in carbon capture, utilization, and storage (CCUS). The Federal Budget 2022 proposes a refundable ITC for businesses that incur eligible CCUS expenses. Applicable to Suncor, the ITC would apply to CCUS projects that permanently store captured CO_2 through eligible use, which includes dedicated geological storage. From 2022 to 2030, a 50% ITC for investment in equipment to capture CO_2 is proposed for CCUS projects, with that rate being halved starting in 2031. With Suncor's participation in the Pathways Alliance, with the objective of net-zero emissions from operations by 2050, the ITC is an incentive for CCUS project development. Suncor is working with the government on developing the ITC and other fiscal supports to enable decarbonization investments across company assets.

On October 4, 2022, ECCC released "Draft Guidance for Best-in-Class GHG Emissions Performance by Oil & Gas Projects," which is a component of the SACC supporting the federal impact assessment process. This guidance document outlines information for proponents of oil and gas projects that will undergo a federal impact assessment to demonstrate best-in-class GHG emissions performance on a global scale. This best-in-class GHG emissions performance could be at project startup or proponents could provide a plan for technology implementation over time to achieve global standards. Further guidance is expected to be released in 2023. At this time, Suncor is unable to predict the impact this update will have on its business.

Provincial GHG and Fuel Regulations

Alberta

Oil Sands Emissions Limit Act

The *Oil Sands Emissions Limit Act* sets an emissions limit of 100 Mt of CO_2e per year in Alberta 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 in Alberta are estimated to be between 70 to 80 Mt per year, including existing upgrading capacity but excluding cogenerated electricity sold to the Alberta power grid. The mechanics of implementation and enforcement of this legislation remain under review by the Government of Alberta and it is therefore not yet possible to predict the long-term impact on Suncor.

Technology Innovation and Emissions Reduction Implementation Regulation

The *Technology Innovation and Emissions Reduction Implementation Regulation* (TIER), a regulation enacted under Alberta's *Emissions Management and Climate Resilience Act*, is a provincial carbon pricing regulation for large industrial emitters that came into force on January 1, 2020. TIER meets the federal government's stringency benchmark criteria for large industrial emitters for 2022 and 2023. As a result, the federal OBPS applicable to large industrial emitters, described under GGPPA, will not apply to Alberta. TIER applies primarily to large industrial facilities in Alberta with CO_2e emissions in excess of 100,000 tonnes per year which, for Suncor, includes Oil Sands Base Mine, Firebag, MacKay River, Fort Hills, the Edmonton refinery and Syncrude. Such facilities are required to reduce emissions intensity from their historical performance using facility-specific benchmarks or from the performance of the top facility in a sector using an approved high-performance benchmark. Facilities that outperform the higher of their facility-specific or high-performance benchmark can generate emission performance credits, while facilities that do not meet their emission intensity target can meet compliance obligation through i) use of emissions performance credits that are generated by other regulated facilities; ii) use of Alberta-based emission offsets that are generated by projects that have voluntarily reduced their GHG emissions following an approved quantification protocol; and/or iii) pay into the TIER fund, which is priced at $50 per tonne of CO_2e as of January 1, 2022.

In June 2022, the Alberta government undertook a legislated review of TIER that was mandated to be completed by the end of 2022. The purpose of the review and related engagement was to update policy,

review the system design and recommend regulatory changes to the TIER system. The TIER regulations were amended in December 2022. The amendments maintain federal equivalency from 2023 to 2030. The most impactful change is the increased stringency on the benchmark tightening rate on oil sands facilities from 1% to 2% from 2023 to 2028 and 4% from 2029 to 2030. Other notable amendments include sequestration credits and capture recognition tonnes that are established as new instruments that can be used under TIER and also for CFR credits, the increase to annual credit usage limits, and the tightening of electricity benchmarks starting in 2023. Suncor is incorporating these amendments into long-term forecasting and planning.

The carbon price under TIER increased from $50 per tonne of CO_2e in 2022 to $65 per tonne of CO_2e on January 1, 2023.

Electricity generators will continue to be subject to the existing "good-as-best-gas" standard of 370 tonnes of CO_2e per GWh. Currently, Suncor's cogeneration facilities at its Oil Sands Base Mine, Firebag, Fort Hills and Syncrude operations earn credits because the electricity generated is more efficient than the electricity standard.

Under TIER, each of Suncor's facilities is required to comply with the least stringent of either: (i) a facility-specific benchmark based on the average historical performance of that facility; or (ii) a high-performance benchmark. All of Suncor's operations fall under the facility-specific benchmark. The high-performance benchmark is a product-specific, high-performance benchmark reflecting emissions intensity of high performance in a sector (calculated as average emissions intensity of the top 10% of facilities). Under TIER, facilities emitting over their prescribed benchmarks will be subject to a compliance obligation. Compliance obligations can be met by retiring eligible offsets or emission performance credits, or paying the prevailing carbon price. Offset credits can be generated by conducting eligible activities prescribed by provincial protocols.

Federal RFR

The renewable fuel mandate in Alberta is governed by the federal RFR - refer to the Industry Conditions – Climate Change and GHG Emissions - Canadian Federal GHG and Fuel Regulations section.

Carbon Tax

In addition to the above, the federal carbon price under the GGPPA also applies to consumers' GHG emissions resulting from the combustion of fossil fuels consumed, for example, for heating and transportation. Carbon tax is applied at the prevailing federal carbon price to consumer fuel at the point of sale, which is later remitted to the federal government. Under the GGPPA, the carbon price increased from $50 per tonne of CO2e in 2022 to $65 per tonne of CO2e on January 1, 2023.

British Columbia

CleanBC Roadmap to 2030

CleanBC establishes a series of actions to put the province on a trajectory that would allow it to achieve its 2030 emissions reduction target and eventually its net-zero target by 2050. The actions included in the CleanBC Roadmap to 2030 include: a commitment to increase the price on carbon to meet or exceed the federal benchmark, with supports for people and businesses; adoption of ZEVs to 90% by 2030 and 100% ZEVs by 2035; the development of new ZEV targets for medium- and heavy-duty vehicles; increased clean fuel and energy-efficiency requirements (such as increasing stringency of the B.C. low carbon fuel standard from 20% carbon intensity reduction by 2030 to 30% and doubling the target for renewable fuels produced in B.C. to 1.3 billion litres by 2030); the completion of B.C.'s electric highway by 2024; a reduction of methane emissions from oil and gas by 75% by 2030 and the elimination of all industrial methane emissions by 2035; requirements for new large industrial facilities to work with B.C. government to demonstrate how they align with B.C.'s legislated targets and submit plans to achieve net-zero emissions by 2050; and support for innovation in areas like low-carbon hydrogen, the forest-based bioeconomy and negative emissions technology.

B.C. Low Carbon Fuel Standard

In addition to the carbon tax, the Province of British Columbia is addressing transportation emissions through British Columbia's low carbon fuel standard (BC-LCFS). The BC-LCFS establishes annual carbon

intensity reduction targets in gasoline and diesel fuels, which are achieved by blending renewable liquid fuels, as well as switching to lower emission technologies in transportation. Suncor is able to flow through the BC-LCFS costs to consumers. In spring 2022, the Government of British Columbia amended the Greenhouse Gas Reduction (Renewable & Low Carbon Fuel Requirements Regulation) Act to add jet and marine fuel classes. Effective January 1, 2023, the Government of British Columbia amended the Renewable & Low Carbon Fuel Requirements Regulation to increase carbon intensity reduction targets on gasoline and diesels, from 20% by 2030 to 30% by 2030. The demand for low-carbon transportation options is expected to reduce the demand for gasoline and diesel, and increase the demand for renewable liquid fuels and electric vehicle charging.

B.C. Zero Emission Vehicle Mandate

The Province of British Columbia passed the Zero-Emission Vehicles Act (ZEV Act) on May 30, 2019. The ZEV Act requires automakers to meet an escalating annual percentage of new light-duty ZEV sales and leases, reaching 10% of light-duty vehicle sales by 2025, 30% by 2030 and 100% by 2040. However, the Government of British Columbia announced on April 1, 2022 that it is looking to advance the schedule to 26% by 2026, 90% by 2030 and 100% by 2035 and has identified required complementary measures.

B.C. Carbon Tax

In addition to the above, the provincial carbon price also applies to consumers' GHG emissions resulting from the combustion of fossil fuels consumed, for example, for heating and transportation. This carbon tax is applied at the published provincial carbon price to consumer fuel at the point of sale, legislated as a provincial sales tax, which is later remitted to the provincial government. The effective carbon price, shown as a price per volume of fuel, increased from $45 per tonne of CO2e in 2021 to $50 per tonne of CO2e on April 1, 2022.

Newfoundland and Labrador

Newfoundland and Labrador's carbon pricing program 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 and other fuels combusted in the province. Performance standards for large industrial facilities are legislated under the *Management of Greenhouse Gas Act* and associated regulations, which apply to all facilities that emit 15,000 tonnes of CO_2e or more per annum and therefore apply to Terra Nova (when it is operating), Hibernia, White Rose and Hebron. Consistent with the federal carbon pricing scheme at the time, the Newfoundland and Labrador carbon price in 2021 was $40 per tonne of CO_2e and increased to $50 per tonne of CO_2e in 2022. On November 22, 2022, a decision was made by the Government of Canada to impose the federal carbon pollution pricing system on the province, effective July 1, 2023. This will increase the carbon tax to $65 per tonne of CO_2e.

Offshore production facilities were assigned an annual GHG reduction target of 10% in 2021 and 12% in 2022 below the facility's 2016-2017 historical average emissions-to-output ratio, excluding methane emissions from venting and fugitive sources.

Under Development

The *Management of Greenhouse Gas Act* established a fund to support energy-efficient and clean technology investments 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.

Ontario

Greenhouse Gas Emissions Performance Standards

As of January 1, 2022, the "made in Ontario" GHG Emissions Performance Standards (EPS) superseded and replaced the federal OBPS. Unlike the federal OBPS, which applied to facilities that generated more than 25,000 tonnes of GHG emissions per year (including Suncor's Sarnia refinery and St. Clair ethanol

plant), the EPS applies to facilities that generate more than 50,000 tonnes of GHG emissions per year. Suncor does not expect any material changes to its business as a result of this change, with the exception of a less favourable stringency performance standard for cogeneration technology required to generate credits for the technology at the federal level.

Cleaner Transportation Fuels Regulation

The *Cleaner Transportation Fuels Regulation* under the *Environmental Protection Act* imposes renewable content in gasoline and diesel to support the provincial government's goal of reducing GHG emissions by 30% below 2005 levels by 2030 as set out in the Made-in-Ontario Environment Plan.

Carbon Tax

In addition to the above, the federal carbon price under the GGPPA also applies to consumers' GHG emissions resulting from the combustion of fossil fuels consumed, for example, for heating and transportation. Carbon tax is applied at the prevailing federal carbon price to consumer fuel at the point of sale, which is later remitted to the federal government. Under the GGPPA, the carbon price increased to $50 per tonne of CO_2e in 2022, with another increase expected in 2023 to $65 per tonne of CO_2e.

Carbon Capture and Storage Regulations

The Ontario government recently signaled that they are interested in drafting legislation to enable carbon capture and storage activities in the province. The design of the regulations is slated to take place with stakeholder input over the Spring and Fall of 2023.

Quebec

Implemented in 2013, Quebec's cap-and-trade system for GHG emissions applies to companies in the industrial and electricity combustion sectors that emit 25,000 tonnes or greater of CO_2e per year and distributors of fossil fuels used in Quebec. Quebec's cap-and-trade system is linked to California's and is part of the Western Climate Initiative (WCI), an organization set up to help members in U.S. states and Canadian provinces execute their cap-and-trade systems. Allowances and offsets are tradeable across the WCI. In Quebec, emitters are required to either reduce their emissions or purchase eligible emissions allowances to cover their emissions beyond any free emissions allowances they receive from the government. The cap on overall annual GHG emissions and the maximum amount of free allowances allocated to regulated emitters are established by the province. The emissions at Suncor's Montreal refinery are subject to Quebec's cap-and-trade system, while the Montreal Sulphur Plant is a voluntary participant of the cap-and-trade system. The cost to purchase emissions allowances under the cap-and-trade system associated with consumer fuel purchases is passed on to consumers at the point of purchase.

In August 2022, the Government of Quebec published the final regulation on its cap-and-trade system for the 2024-2030 compliance period. The changes include an annual decline of the facility-specific emissions cap of 2-4%, depending on the sector, compared to the current 1%. The cap decline for Suncor's major industrial sites in the province will be around 2.6% for the next 10 years. The additional funds collected from the increased compliance costs will be set aside and available to the regulated industrial site to invest in GHG reduction projects and other emerging low-carbon-intensity technologies.

In the fall of 2020, the Quebec government introduced its *2030 Plan for a Green Economy* to help achieve its 2030 GHG emissions reduction target, namely a 37.5% reduction compared to 1990 levels, and to reach carbon neutrality by 2050. With respect to renewable fuel content, the plan contemplates requiring the blending of a minimum volume of 15% of ethanol into gasoline and a minimum volume of 10% bio-based diesel into diesel fuel by 2030. The plan will include a mandate to phase out the sale of new gasoline-powered vehicles by 2035.

On January 1, 2023, the *Regulation Respecting the Integration of Low Carbon-Intensity Fuel Content into Gasoline and Diesel Fuel* came into effect. The regulation requires integration of low-carbon-intensity fuel

content of 10% volume in gasoline and 3% in diesel, increasing to 15% volume in gasoline and 10% in diesel by 2030.

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) report their GHG emissions.

In 2019, the State of Colorado passed a suite of energy and climate change related legislation that includes, but is not limited to, setting statewide targets to reduce 2025 GHG emissions by at least 26%; 2030 GHG emissions by 50%; and 2050 GHG emissions by 90%, using a 2005 baseline year; and to transition Colorado's electricity system to become 80% renewable by 2030 and 100% renewable by 2040. The legislation requires several regulations to be adopted through rulemakings to support implementation, which will address, among other things, reducing GHG emissions from the oil and gas sector, the industrial and manufacturing sector and other sectors, and requirements to monitor, measure and report GHG emissions.

In 2021, the State of Colorado passed a law (HB 21-1266) that requires the industrial and manufacturing sector as a whole, which includes refining, to reduce 2030 GHG emissions by 20% using a 2015 baseline. However, energy-intensive trade-exposed (EITE) manufacturing facilities that currently employ GHG best available emission control technologies and best available energy efficiency practices, are required to reduce GHG emissions by 5%. The Commerce City refinery is currently not designated as an EITE facility.

Colorado is expected to adopt GHG regulations through rulemakings for non-EITE facilities in the industrial and manufacturing sectors in 2023.

The impact on Suncor, including its Commerce City refinery, is not clear at this time.

Under Development

President Biden's administration has confirmed its commitment for the U.S. to rejoin the Paris Agreement. As part of this commitment, the U.S. will reduce GHG emissions from 2005 levels by 50%-52% by 2030. The President has also committed to creating a carbon-pollution-free power sector by 2035 and reaching net-zero emissions economy-wide by 2050. To meet these climate commitments, the President is expected to use his executive authority to re-establish standards for power plant emissions, reform vehicle efficiency standards, re-establish methane emissions limits and integrate climate change into foreign and trade policy and national security strategies. Due to political uncertainty, the extent of these initiatives being implemented is not clear at this time. In addition, the United States Climate Alliance, a network consisting of the governors of 25 states, which includes Colorado, remain committed to advancing efforts to address climate change through policies that encourage investment in clean energy, energy efficiency and climate resilience. Suncor continues to monitor these developments and constructively participate where appropriate.

International Regulations

Suncor's U.K. non-operated assets are subject to the U.K. Emissions Trading Scheme (UK ETS). Each of the EU ETS and UK ETS work on a cap-and-trade principle, requiring the setting of emission limits for the sectors covered by the scheme. Each year, emissions allowances equivalent to the cap are either auctioned or distributed as free allowances to participants. A secondary market is also available for participants to buy and sell allowances from each other. Each year, regulated facilities surrender emissions allowances to cover their reportable emissions. The emissions cap is reduced over time to reduce total emissions. Both the EU ETS and UK ETS have mechanisms to effectively establish floor and ceiling prices to manage the cost of credits.

Compliance Costs

The following table outlines the costs associated with the GHG emissions policies for the company's equity share of operated assets:

Reporting Segment ($ millions)	2021	2022(3)	2023 (Estimate)
Oil Sands(1)	52.5	96.8	182.3
Exploration and Production	nil	nil	0.7
Refining and Marketing(2)	13.9	20.1	27.4

(1) Compliance costs for Suncor are increasing under TIER due to the increase in stringency of the facility benchmarks and rise in prevailing carbon prices. Refer to the TIER section above. A portion of the 2023 costs is estimated based on Fort Hills working interest of 68.76%, an increase from 54.11% in 2021 and 2022.

(2) Compliance costs are increasing over time based on the increasing GHG cost per tonne and decreasing GHG emissions targets per federal and provincial regulations.

(3) A portion of 2022 costs is based on estimates and may differ from actuals that will be finalized upon later settlement of compliance costs.

Land Use and Natural Resources Management Frameworks

Canadian Land Use and Natural Resources Management

Alberta Land Use and Water Management Regulatory Frameworks

The Lower Athabasca Regional Plan (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 land leases owned or operated by Suncor or its affiliates.

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

- **Surface Water Quality Management Framework for the Lower Athabasca River.** This framework provides a basis with which to monitor and manage long-term, cumulative changes in water quality within the Lower Athabasca River. The framework includes quality limits and triggers for various indicators, based on existing guidelines from the Alberta provincial government, Canadian Council of Ministers of the Environment, Health Canada and the U.S. EPA. Regulatory and/or management actions will occur when triggers or limits are reached or exceeded.
- **Surface Water Quantity Management Framework.** This framework 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. 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 Mining Water Management Sharing Agreement that is submitted to Fisheries and Oceans Canada and Alberta Environment and Parks as required by the framework.

- **Groundwater Management Framework.** The Groundwater Management Framework aims to manage non-saline groundwater resources in a sustainable manner and protect groundwater resources from contamination and overuse. 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.** The Tailings Management Framework (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 tailings associated with oil sands mining and extraction. The Tailings Directive follows TMF guidance by requiring fluid tailings inventory triggers and a limit, as well as management actions such as a compliance levy and financial security through the Mine Financial Security Program (MFSP), to support the overarching 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.

The Alberta government has also been working to develop oil sands water release guidance. In addition, ECCC's work to meet its 2025 timeline for development of the federal Oil Sands Mine Effluent Regulation (OSMER) is progressing. If implemented, OSMER will help enable oil sands companies to return treated mine water to the Athabasca River.

Air Quality Regulations

Air quality in Suncor's operating areas is an increasing focus and has resulted in the introduction and/or update of policies and regulations of air pollutants, odours and health standards to drive performance improvement. Overall, regulators are moving toward setting new, more stringent limits that often require updating or replacing equipment, as well as additional monitoring and reporting requirements. Air quality regulations impacting Suncor's Canadian operations are listed below:

- The LARP discussed in the Land Use and Natural Resources Management section also includes the 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 and/or management actions will occur when triggers or limits are reached or exceeded.
- Canadian Ambient Air Quality Standards (CAAQS) – The Canadian Council of Ministers of the Environment, with the exception of Quebec, have implemented the Air Quality Management System. One of the key elements of the system is the ambient air quality objectives for selected air pollutants set out under the CEPA, which include limits for fine particulate matter (PM 2.5), ground-level ozone, NO_2 and SO_2. It is a provincial responsibility to ensure implementation of the nationwide standards of CAAQS are achieved. All of Suncor's Canadian operations, with the exception of the Montreal refinery, adhere to CAAQS. The Montreal refinery adheres to Montreal air quality regulation (CMM regulation 90). The impacts are highest for the operations located in airsheds that are likely to exceed CAAQS limits, including areas such as the Wood Buffalo Region (Oil Sands Base, Fort Hills, Firebag, MacKay River and Syncrude), the Edmonton region (Edmonton refinery) and the Sarnia region (Sarnia refinery and St. Clair ethanol plant). Suncor currently has several NO_2 and SO_2 emissions reductions projects underway to mitigate the risk of potentially exceeding the CAAQS limits.
- Alberta Ambient Air Quality Objectives (AAAQO) – AAAQO and guidelines are issued by Alberta Environment and Parks under Section 14 (1), of the *Environmental Protection and Enhancement Act*. AAAQO are developed to protect Alberta's air quality and are used as part of industrial approvals to regulate facility operations. All industrial indoor and outdoor facilities must be

designed and operated such that the ambient air quality remains below AAAQO. AAAQOs are becoming increasingly stringent, with scientific evidence and knowledge showing that health and environmental effects occur at low ambient air concentrations. Alberta Environment and Parks is currently reviewing NO_2 and SO_2 AAAQO in light of the 2020 CAAQS, which could have significant cost implications for Suncor's operations in Alberta.

- Methane Regulations – The Canadian federal government, through the ECCC, and the Government of Alberta both have methane regulations. The federal regulations came into effect in January 2020 to fulfil Canada's commitment to reduce methane emissions from the upstream oil and gas sector by 40% to 45% below 2012 levels by 2025. On November 11, 2020, the Government of Alberta reached a formal equivalency agreement with ECCC, which will replace the federal regulations for up to five years. Alberta's Methane Emission Reduction Regulation will impact Suncor's In Situ operations in Alberta through changes to the measurement, monitoring and reporting of methane emissions to support improved understanding and tracking of oil and gas methane emissions. Similar equivalency agreements to the federal methane regulations are also in effect in British Columbia and Saskatchewan, which have their own regimes. Environment Canada acknowledges that the upstream oil and gas sector is on track to achieve the 2025 methane reduction target. However, in support of the Global Methane Pledge, Canada committed to reducing oil and gas sector methane emissions by at least 75% below the 2012 level by 2030. Accordingly, ECCC published a draft regulatory framework on November 12, 2022, for 30-day public consultation. Industry associations are actively engaged with ECCC in developing a policy that will effectively attain methane reductions while being practical, efficient to implement and manageable for regulatory bodies and industry. This revised methane emissions reduction target is expected to incur an added cost for Suncor In Situ operations to comply with the additional emission reduction requirements.
- Volatile Organic Compound (VOC) Regulations for Upgrading & Refining – *Reduction in the Release of Volatile Organic Compounds Regulations (Petroleum Sector)* came into effect on January 1, 2020, with additional parts of the regulation impacting the oil and gas industry coming into effect in January 2022 and 2023. This regulation limits the release of VOCs, including carcinogenic substances such as benzene and 1,3 butadiene, by requiring Canadian refineries and upgrader facilities to take measures to reduce leaks from equipment components (valves, pumps, connectors, etc.). This regulation requires facilities to conduct leak detection and repairs on their equipment, as well as monitor VOC concentrations at the facility perimeter. Suncor will incur costs to comply with the requirements but will also recover products that would otherwise have been lost from leaking equipment components.
- Ontario regulations for addressing sulphur dioxide emissions – The *Addressing sulphur dioxide emissions from Ontario's petroleum facilities* regulation was published in February 2022. This regulation requires SO_2 emissions reductions from the Sarnia refinery, under normal operation as well as under maintenance and upset conditions. The refinery already includes many of the best practices in terms of SO_2 reduction, and it is working with Aamjiwnaang First Nation, Walpole Island First Nation and the Ministry of the Environment, Conservation and Parks towards additional SO_2 emissions reductions.

U.S. Land Use and Natural Resources Management

Water Management Regulations

The Commerce City refinery's water discharge permit is currently subject to a renewal process. In late 2021, the Water Division for the Colorado Department of Public Health and Environment (CDPHE) issued a draft water permit, which contains new and additional proposed requirements, including with respect to those related to per- and polyfluoroalkyl substances, that could impose an additional financial impact on the company. Suncor is reviewing the draft permit and will proceed through the permit renewal process.

Air Quality Regulations

Air quality in Suncor's U.S. operating areas is an increased focus and has resulted in the introduction and/or update of policies and regulations of air pollutants, odours and health standards to drive performance improvement. Overall, regulators are moving toward setting new, more stringent limits that often require updating or replacing equipment, as well as additional monitoring and reporting requirements. Air quality regulations impacting Suncor's U.S. operations are listed below:

- Colorado *House Bill 21-1189 (Concerning Additional Public Health Protections in Relation to the Emission of Air Toxics)* – This bill, which was signed into law in 2021, amended prior legislation passed in 2020 (Colorado *House Bill 20-1265*). The original law created a new category of covered air toxics (hydrogen cyanide, hydrogen sulfide and benzene), a new category of covered facilities defined by reporting certain thresholds of any of the covered air toxics and required such facilities to conduct community outreach regarding incident communications and implement the use of an emergency notification service for certain incidents. The new law redefined the covered facilities by North American Industry Classification System, requires the facilities to conduct real-time fenceline monitoring for covered air toxics, and requires the CDPHE to conduct community air monitoring to be paid for by the covered facilities. This will increase monitoring and reporting requirements for Suncor's Commerce City refinery.
- *Colorado House Bill 21-1266 (Concerning Efforts to Redress the Effects of Environmental Injustice on Disproportionately Impacted Communities)* – This bill, which was signed into law in 2021, requires, among other things, that the Colorado Air Quality Control Commission (Commission) adopt rules regarding enhanced air modeling and air monitoring in connection with certain permit applications for new and modified stationary sources located in disproportionately impacted communities. The Commission may also consider adopting requirements for enhanced air monitoring of existing sources. The rulemaking is scheduled to be conducted in 2023, and may impose new requirements on the Commerce City refinery.
- Colorado *House Bill 22-1244 (Public Protections from Toxic Air Contaminants)* – This bill was signed into law in 2022 and aims to protect public health and the environment. The bill requires the development of an annual air toxics emissions inventory, beginning in 2024. The CDPHE will develop a monitoring program by January 2024 to determine the concentration of toxic air contaminants. Beginning in July 2027, when applying for a new or modified air pollution permit, the owner of source will be required to submit an analysis of the impacts of the stationary source's toxic air contaminant emissions. In addition, to protect public health and the environment, the CDPHE may reopen any existing air pollution permit and require a decrease or a cessation of the applicable emissions over the shortest practicable time until the emissions no longer contribute to concentrations in excess of a health-based standard. The House Bill also requires the CDPHE to develop emission control regulations by April 30, 2026. The implementation of this bill will increase reporting requirements for Suncor's Commerce City refinery due to the need to develop the annual toxics emission inventory.
- Colorado *House Bill 21-1303 (Global Warming Potential for Public Project Materials)* – This bill was signed into law in July 2021 and requires the Colorado Office of the State Architect (vertical construction) and Colorado Department of Transportation (horizontal construction) to establish maximum acceptable global warming potentials (based on the industry average of global warming potential emissions) for various materials, including asphalt. By January 1, 2026 (2025 for horizontal construction including roads), and every four years thereafter, the Office of the State Architect will be required to review and adjust the global warming potential for each material listed in the bill (which includes asphalt). Environmental Product Declarations will be required from a vendor for any government contract. A contractor will be required to provide an environmental product declaration prior to the commencement of any work. The implementation of this bill may negatively impact Suncor if it is determined that its asphalt products exceed the maximum acceptable global warming potential.
- U.S. Regional Haze State Implementation Plan Revisions and Regulation 23 Development – The Regional Haze Rule under the EPA calls for state and federal agencies to work together to

improve visibility in national parks by addressing the primary pollutants that cause regional haze, including particulate matter, NOx and SO_2. Emission sources from industry include heaters/boilers, fluid catalytic cracking units and sulphur recovery complexes. Improvements to one of the sulphur recovery units at Suncor's Commerce City refinery by 2028 will be required to meet this regulation.

- In 2021, Colorado conducted a rulemaking to conduct revisions to Regulation 7 (Controls of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions), including requirements to implement NOx Reasonably Available Control Technology for process heaters at major sources. Certain of these rule revisions will apply to the Commerce City refinery.
- Title V air operating permits, under the federal *Clean Air Act,* apply to the three plants in the Commerce City refinery. In 2022, the Plant 2 Title V permit was issued by the CDPHE. New requirements under this permit include annual air emissions inventory, development of a public-facing continuous emissions monitoring website and a quarterly community report detailing all air emissions exceedances. Plants 1 and 3 are undergoing permit renewal applications which are expected to be issued in 2023.

Biodiversity

Governments are increasing the rigour of existing acts/regulations and issuing changes aimed at improved environmental protection, including habitat and species protection. Policy development and engagement is complex. Stakeholders are concerned by the slow progress by government to protect habitat. In addition, traditional land use rights of Indigenous communities are inclusive of caribou herds and the issue of caribou habitat is often a recurring theme in Statements of Concerns during the regulatory process. Within the Wood Buffalo region, an area with more than ~40% wetland cover, many of Suncor's current and future projects are within identified caribou ranges.

In October 2020, Alberta Environment and Parks and ECCC announced they had finalized a *Species at Risk Act* (SARA) Section 11 Conservation Agreement for Alberta's caribou populations. The agreement identifies timelines for the Alberta sub-regional planning process and establishes the collaborative responsibilities of the provincial and federal governments. Under this agreement, industry will continue to work with the Government of Alberta as part of the sub-regional planning process.

The Alberta Wetland Policy has been in effect province-wide since July 2016. The Policy's goal is "to conserve, restore, protect and manage Alberta's wetlands." For certain new project types, an upfront detailed wetland assessment must be performed for all surface disturbances. Under the policy, where avoidance and minimization efforts are not feasible or prove ineffective, wetland replacement is required at a ratio determined by wetland value from 1:1 to 8:1. Proponents can fulfil their replacement obligations through a combination of options: replacing at a ratio determined by wetland value from 1:1 to 8:1; paying into the replacement in lieu program; or purchasing available credits from a third-party wetland bank. Wetland replacement costs are expected to be especially high for future oil sands projects and expansions since there is limited to no opportunity to avoid or minimize impacts to wetlands. Suncor continues to work with the Government of Alberta to resolve any ongoing implementation challenges.

The fifteenth conference of the parties to the UN Convention on Biodiversity (COP15), held in December 2022, led to the ratification of the Kunming-Montreal Global Biodiversity Framework (GBF). The GBF includes four goals and 23 targets to safeguard nature by halting and reversing biodiversity loss, putting nature on a path to recovery by 2050. Key global targets include commitments to the restoration of degraded ecosystems; conservation and protection of land and water; disclosure of risks, impacts and dependencies along the operations, supply/value chains and portfolios for large and transnational companies; and the elimination, phase-out or reform of incentives, including subsidies, that are harmful to biodiversity. As a signatory to the agreement, Canada will develop a National Biodiversity Strategy and Action Plan to meet the goals and targets of the GBF. This will create an emphasis on positive actions for nature related to mitigation, restoration, reclamation and disclosure that could influence Suncor's operations and/or create potential limitations due to protected and conserved area targets. Suncor will work with the governments of Alberta and Canada to understand the role and expectations of business in meeting the goals and targets of the GBF.

Dam Integrity

The Government of Alberta has a rigorous and stringent regulatory system to manage dams within the province. Suncor's internal programs aim to provide compliance and additional oversight in accordance with industry-leading guidelines. The Mining Association of Canada's (MAC) *Guide to the Management of Tailings Facilities* and the Canadian Dam Association's (CDA) *Dam Safety Guidelines*, and their associated technical bulletins are considered leading practice guidelines worldwide. At the international level, the *Global Industry Standard on Tailings Management* (GISTM) provides principles of practice for all new dams for the purpose of raising the level of diligence for tailings dams around the world, with particular attention to old and deteriorating dams. MAC and CDA have worked to gain additional alignment with the GISTM. Suncor operations are in alignment with the principles and requirements through commitments to AER regulations, as well as MAC and CDA guidelines. Additionally, Suncor has worked with MAC and CDA to gain alignment between their respective guidelines and the GISTM.

Reclamation

Suncor is committed to surface reclamation and remediation of lands affected by its operations. The Government of Alberta's Mine Financial Security Program (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, falling below a specified asset to liability ratio, 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. In 2022, a review of MFSP was conducted by the Government of Alberta with expected revisions to the MFSP to be identified in 2023 and applied to the 2024 MFSP filing.

Suncor is the first company to surface reclaim an oil sands tailings pond, convert a second pond to a fluid tailings treatment area, and make another pond trafficable with coke capping. Under the TMF, initial tailings management plans have been submitted and approved for Suncor Base Plant (2017), Syncrude Aurora North (2018), Syncrude Mildred Lake (2019) and Fort Hills (2019). In 2022, updates to the Suncor Base Plant and Fort Hills tailings management plans were submitted.

Another component identified in the TMF is integrated water management. In order to support successful closure and reclamation, water quantity must be reduced, and quality must be managed. The Alberta government has been working to develop provincial water release policy guidance. The five-year review for the TMF under LARP could start in 2023 and result in changes to tailings management requirements.

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 annual cost to Suncor under the Monitoring Plan, including Suncor's net share of Syncrude, was $13.2 million for 2022, which will be paid in early 2023. A continued focus on governance and planning is important for the program to achieve its objectives.

Industry Collaboration Initiatives

Environmentally focused collaboration between companies and stakeholders is an important focus for Suncor and the oil sands industry. In 2012, Suncor was a founding member of the Canada's Oil Sands Innovation Alliance (COSIA) with a vision for collaborative action and innovation to enable responsible and sustainable growth of Canada's oil sands while delivering accelerated improvement in environmental performance. Created in 2013, Suncor was a member of the Oil Sands Community Alliance (OSCA) whose purpose was to pursue innovative solutions to build thriving communities and enable responsible oil sands growth through a collaborate approach and engagement amongst stakeholders including

municipalities, government, and industry. In 2021, Suncor was a founding member of the Oil Sands Pathways to Net Zero Alliance, an alliance of six companies accounting for 95 percent of oil sands production, committing to work together on an ambitious plan to reduce GHG emissions from oil sands production with the goal of achieving net zero GHG emissions by 2050.

On June 15, 2022, Canada's major oil sands producers announced the combination of three existing industry groups, with Suncor a member of each, focused on innovation and sustainable development into a single organization called the Pathways Alliance. This new organization incorporates the Oil Sands Pathways to Net Zero Alliance, OSCA and COSIA. Subsequent to 2022, the Pathways Alliance was awarded exploratory rights from the Government of Alberta for the proposed carbon capture and storage hub to safely and permanently store CO2 captured from more than 20 oil sands facilities in northern Alberta.

Similarly, Suncor is a founding member of the Clean Resource Innovation Network (CRIN), which is a pan-Canadian network focused on ensuring Canada's energy resources can be sustainably developed and integrated into the global energy supply. CRIN identifies industry challenges to accelerate clean technology commercialization and widespread adoption by bringing together a broad group of stakeholders.

Risk Factors

A discussion of Suncor's risk factors can be found in the "Risk Factors" section in Suncor's annual 2022 MD&A, which section is incorporated by reference herein and available on the Company's SEDAR profile at www.sedar.com.

Dividends

The Board of Directors has established a practice of paying dividends on Suncor's common shares on a quarterly basis. Suncor reviews its ability to pay dividends from time to time with regard to legislative requirements, the company's financial position, financing requirements for growth, cash flow and other factors. Dividends are paid subject to applicable law, if, as and when declared by the Board.

Suncor paid the following common share dividends over the last three years ended December 31:

($ per share)	Year	Q4	Q3	Q2	Q1
2022	1.88	0.52	0.47	0.47	0.42
2021	1.05	0.42	0.21	0.21	0.21
2020	1.10	0.21	0.21	0.21	0.47

Description of Capital Structure

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

As at December 31, 2022, there were 1,337,470,739 common shares issued and outstanding. To the knowledge of the Board of Directors and executive officers of Suncor, no person beneficially owns, or exercises control or direction over, securities carrying 10% or more of the voting rights attached to any class of voting securities of the company. The holders of common shares are entitled to attend all meetings of shareholders and vote at any such meeting on the basis of one vote for each common share held. Common shareholders are entitled to receive any dividend declared by the Board on the common shares and to participate in a distribution of the company's assets among its shareholders for the purpose of winding up its affairs. The holders of the common shares shall be entitled to share, on a pro rata basis, in all distributions of such assets.

Petro-Canada Public Participation Act

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

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

Credit Ratings

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

The following table shows the ratings issued for Suncor by the rating agencies noted herein as of March 6, 2023. The credit ratings are not recommendations to purchase, hold or sell the debt securities in as much as such ratings do not comment as to the market price or suitability for a particular investor. Any

rating may not remain in effect for any given period of time or may be revised or withdrawn entirely at any time by a rating agency in the future if, in its judgment, circumstances so warrant.

	Senior Unsecured	Outlook	Canadian Commercial Paper Program	U.S. Commercial Paper Program
S&P Global Ratings (S&P)	BBB	Negative	Not rated	A-2
DBRS Morningstar (DBRS)	A (low)	Stable	R-1 (low)	Not rated
Moody's Investors Service (Moody's)	Baa1	Stable	Not rated	P-2
Fitch Ratings (Fitch)	BBB+	Stable	Not rated	F-1

S&P credit ratings on long-term debt are on a rating scale that ranges from AAA to D, representing the range of such securities rated from highest to lowest quality. A rating of BBB by S&P is the fourth highest of 10 categories. An obligation rated BBB exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to weaken the obligor's capacity to meet its financial commitments on the obligation. The addition of a plus (+) or minus (-) designation after the rating indicates the relative standing within a particular rating category. S&P credit ratings on commercial paper are on a short-term debt rating scale that ranges from A-1 to D, representing the range of such securities rated from highest to lowest quality. A U.S. rating of A-2 is the second highest of six categories, indicating a slightly higher susceptibility to the adverse effects of changes in circumstances and economic conditions than obligations in higher categories; the obligor's capacity to meet its financial commitment on the obligation is satisfactory.

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

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

Fitch's long-term credit ratings are on a rating scale that ranges from AAA to BBB (investment grade) and BB to D (speculative grade), which represents the range from highest to lowest quality of such securities rated. The terms "investment grade" and "speculative grade" are market conventions and do not imply any recommendation or endorsement of a specific security for investment purposes. A rating of BBB+ is within the fourth highest of 11 categories and indicates that expectations of default risk are currently low. The capacity for payment of financial commitments is considered adequate, but adverse business or economic conditions are more likely to impair this capacity. The modifiers "+" or "-" may be appended to a rating to denote relative status within major rating categories. A Fitch rating outlook indicates the direction a rating is likely to move over a one to two-year period, with rating outlooks falling into four categories: "Positive", "Negative", "Stable" or "Evolving". Rating outlooks reflect financial or other trends that have not yet reached, or have not been sustained at, a level that would trigger a rating action, but which may do so if such trends continue. Positive or Negative outlooks do not imply that a rating change is inevitable and similarly, ratings with Stable outlooks can be raised or lowered without prior revision of the outlook. Where the fundamental trend has strong, conflicting elements of both positive and negative, the rating outlook may be described as Evolving. A Positive Rating Outlook indicates an upward trend on the rating scale. A short-term issuer or obligation rating is based in all cases on the short-term vulnerability to default of the rated entity and relates to the capacity to meet financial obligations in accordance with the documentation governing the relevant obligation. A rating of F-1 for commercial paper is the highest of seven rating categories for short-term debt issuers. Issuers rated F-1 have the strongest capacity for timely payment of financial commitments relative to other issuers or obligations in the same country. Where liquidity profile is particularly strong, a "+" is added to the assigned rating.

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

Market for Securities

Suncor's common shares are listed on the TSX in Canada and on the NYSE in the U.S. The price ranges and the volumes traded on the TSX for the year ended December 31, 2022 are as follows:

	Price Range (Cdn$)		Trading Volume
	High	Low	(000s)
2022			
January	36.69	32.08	195,702
February	38.78	35.79	247,193
March	43.12	37.43	328,779
April	47.89	38.74	153,622
May	53.17	43.13	218,794
June	53.62	42.28	250,108
July	46.72	37.75	131,870
August	45.80	37.98	304,143
September	43.03	36.39	262,597
October	47.31	40.34	136,254
November	50.37	44.16	268,114
December	44.66	40.10	273,371

For information in respect of options to purchase common shares of Suncor and common shares issued upon the exercise of options, see Note 26 to the 2022 audited Consolidated Financial Statements, which is incorporated by reference into this AIF and available on SEDAR at www.sedar.com.

Directors and Executive Officers

Directors

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

Name and Jurisdiction of Residence	Period Served and Independence	Biography
Ian R. Ashby[1][2] California, U.S.	Director since 2022 Independent	Ian Ashby is the former president of BHP Billiton's iron ore customer sector group. Mr. Ashby has almost 40 years of experience in the mining industry, including 25 years in a wide variety of roles with BHP Billiton in its iron ore, base metals and gold businesses in Australia, the U.S., and Chile, as well as project roles in the corporate office, ultimately leading the company's iron ore business. Since retiring from BHP Billiton in 2012, Mr. Ashby has taken on a number of advisory and board roles with other mining and related organizations. He currently serves as an independent director on the boards of Anglo American plc and IAMGOLD Corporation. He has served as a director on the boards of New World Resources PLC, Genco Shipping & Trading, Nevsun Resources Ltd., and Alderon Iron Ore Corp. He has also served in an advisory capacity with Apollo Global Management and Temasek. Mr. Ashby holds a bachelor of engineering (mining) degree from the University of Melbourne in Australia.
Patricia M. Bedient[2][3] Washington, U.S.	Director since 2016 Independent	Patricia Bedient retired as executive vice president of Weyerhaeuser Company, one of the world's largest integrated forest products companies, on July 1, 2016. From 2007 until February 2016, she also served as Weyerhaeuser's chief financial officer. Prior to this, she held a variety of leadership roles in finance and strategic planning at Weyerhaeuser after joining the company in 2003. Before joining Weyerhaeuser, she spent 27 years with Arthur Andersen LLP and ultimately served as the managing partner for its Seattle office and partner in charge of the firm's forest products practice. Ms. Bedient serves on the board of directors of Alaska Air Group, Inc. and Park Hotels & Resorts Inc. and also serves on the Oregon State University board of trustees, and the University of Washington Foster School of Business advisory board. She achieved national recognition in 2012 when the *Wall Street Journal* named her one of the Top 25 CFOs in the United States. She is a member of the American Institute of CPAs and the Washington Society of CPAs. Ms. Bedient received her bachelor's degree in business administration, with concentrations in finance and accounting, from Oregon State University in 1975.

Russell Girling[1][4] Alberta, Canada	Director since 2021 Independent	Russell (Russ) K. Girling was the president and chief executive officer of TransCanada Pipelines Limited and TC Energy Corporation, a North American energy infrastructure company, from 2010 until his retirement on December 31, 2020. Mr. Girling is chair and a director of the board of Nutrien Ltd. Until December 31, 2020, Mr. Girling was a member of the U.S. National Petroleum Council and the U.S. Business Roundtable, and he served as a director of the American Petroleum Institute, the Business Council of Canada and the Business Council of Alberta. Mr. Girling is a graduate of the Institute of Corporate Directors Education Program and holds a bachelor of commerce and a master of business administration (finance) from the University of Calgary.
Jean Paul Gladu[3][4] Ontario, Canada	Director since 2020 Independent	Jean Paul (JP) Gladu previously served as president and chief executive officer of the Canadian Council for Aboriginal Business for approximately eight years. He has over 25 years of experience in the natural resource sector, including working with Indigenous communities and organizations, environmental non-governmental organizations, industry and governments across Canada. Mr. Gladu also serves on the boards of Noront Resources Ltd., Broden Mining Ltd. and the Institute of Corporate Directors. He was appointed chancellor of St. Paul's University College at the University of Waterloo in 2017 and served on the board of Ontario Power Generation. Mr. Gladu has a forestry technician diploma, an undergraduate degree in forestry from Northern Arizona University, an Executive MBA from Queen's University and the ICD.D from the Rotman School of Management at the University of Toronto. Anishinaabe from Thunder Bay, Mr. Gladu is a member of Bingwi Neyaashi Anishinaabek (an Ojibwa First Nation) located on Lake Nipigon, Ontario.

Dennis M. Houston[1][4] Texas, U.S.	Director since 2018 Independent	Dennis Houston served as executive vice president of ExxonMobil Refining & Supply Company, chair and president of ExxonMobil Sales & Supply LLC and chair of Standard Tankers Bahamas Limited until his retirement in 2010. Prior to that, he held a variety of leadership and engineering roles in the midstream and downstream businesses in the ExxonMobil organization. Mr. Houston has approximately 40 years' experience in the oil and gas industry, including over 35 years with ExxonMobil and its related companies. He serves on the board of directors of Argus Media Limited. Mr. Houston has a bachelor's degree in chemical engineering from the University of Illinois and an honorary doctorate of public administration degree from Massachusetts Maritime Academy. He has served on a variety of advisory councils, including an appointment by President George H.W. Bush to the National Infrastructure Advisory Council and serving on the Chemical Sciences Leadership Council at the University of Illinois and the Advisory Council at the Center for Energy, Marine Transportation & Public Policy at Columbia University. He also serves on the Alexander S. Onassis Public Benefit Foundation board, is honorary consul to the Texas Region for the Principality of Liechtenstein and is a board member for the American Bureau of Shipping Group of Companies.
Brian MacDonald[2][3] Florida, U.S.	Director since 2018 Independent	Brian MacDonald is the chief executive officer of CDK Global, Inc., a leading global provider of integrated information technology and digital marketing solutions to the automotive retail and adjacent industries. Prior to joining CDK Global, Mr. MacDonald served as chief executive officer and president of Hertz Equipment Rental Corporation and as interim chief executive officer of Hertz Corporation. He previously served as president and chief executive officer of ETP Holdco Corporation, an entity formed following Energy Transfer Partners' $5.3-billion acquisition of Sunoco Inc., where Mr. MacDonald had served as chair, president and chief executive officer. He was the chief financial officer at Sunoco and held senior financial roles at Dell Inc. Prior to Dell, Mr. MacDonald spent more than 13 years in several financial management roles at General Motors Corporation in North America, Asia and Europe. He previously served on the board of directors for ComputerSciences Corporation (now DXC Technology Company), Ally Financial Inc., Sunoco, Sunoco Logistics L.P. and CDK Global. Mr. MacDonald has a bachelor of science in chemistry from Mount Allison University and an MBA from McGill University.

Lorraine Mitchelmore[1][2] Alberta, Canada	Director since 2019 Independent	Lorraine Mitchelmore has over 30 years' international oil and gas industry experience. She most recently served as president and CEO for Enlighten Innovations Inc., a private-equity backed fuel upgrading technology company. Prior to this, she held progressively senior roles at Royal Dutch Shell. Ms. Mitchelmore joined Shell in 2002, becoming president and country chair of Shell Canada Limited in 2009, in addition to her role as executive vice president of Heavy Oil Americas. Prior to joining Shell, she worked with Petro-Canada, Chevron and BHP Petroleum in the upstream business units in a combination of technical, exploration and development, and commercial roles. Ms. Mitchelmore has been a director of the Bank of Montreal since 2015, Cheniere Energy Inc. since July 2021 and Alberta Investment Management Corporation since January 2022, and has served on the boards of Shell Canada Limited, the Canada Advisory Board at Catalyst, Inc. and Trans Mountain Corporation. Ms. Mitchelmore has a bachelor of science degree (honours) in geophysics from Memorial University of Newfoundland, a master of science degree in geophysics from the University of Melbourne, Australia, and an MBA with distinction from Kingston Business School in London, England.
Christopher R. Seasons[1][4] Alberta, Canada	Director since 2022 Independent	Christopher (Chris) Seasons is a professional engineer with more than 30 years of domestic and international experience in the upstream oil and gas industry. He is currently partner at ARC Financial Corporation, an energy-focused private equity firm. From 2004 until his retirement in June 2014, he served as president of Devon Canada, a subsidiary of Oklahoma-based Devon Energy. Mr. Seasons has long been active in the Calgary community with several not-for-profit organizations including the Canadian Association of Petroleum Producers (former chair and head of numerous committees), the Alberta Children's Hospital Foundation (past chair and current board member), and the United Way Calgary and Area (past co-chair of the annual campaign and current board member). Mr. Seasons graduated from Queen's University with a bachelor of science degree in chemical engineering.

M. Jacqueline Sheppard[3][4] Alberta, Canada	Director since 2022 Independent	Jacqueline (Jackie) Sheppard is the former executive vice president, Corporate & Legal, of Talisman Energy Inc. Ms. Sheppard is chair of the board of Emera Inc. and serves on the board of ARC Resources Ltd. She previously chaired the board of the Research & Development Corporation of the Province of Newfoundland and Labrador, a provincial crown corporation, and has served on several boards such as Pacific NorthWest LNG, Alberta Investment Management Corporation, Seven Generations Energy Ltd. and Cairn Energy PLC. Ms. Sheppard was also a founder and lead director of Black Swan Energy Inc., an Alberta upstream energy company that was private-equity financed and sold to Tourmaline Oil Corp. Ms. Sheppard was named one of Canada's top 100 most powerful women by the Women's Executive Network (WXN) and the National Post from 2002-2007 and has been admitted to the Network's Hall of Fame. In honour of her exceptional merit and integrity in the legal profession, Jackie was appointed Queen's Counsel in 2008. Ms. Sheppard is a Fellow of Institute of Corporate Directors, Canada's preeminent distinction for directors, a Rhodes Scholar, and received an honours degree in jurisprudence, bachelor of arts and master of arts from Oxford University. She earned a bachelor of law degree (honours) from McGill University, and a bachelor of arts degree from Memorial University of Newfoundland.
Eira M. Thomas[3][4] British Columbia, Canada	Director since 2006 Independent	Eira Thomas is a Canadian geologist with over 25 years of experience in the Canadian diamond business. She is currently the chief executive officer and a director of Lucara Diamond Corp., a publicly traded diamond-producing company. Previous roles include serving as chief executive officer and a director of Kaminak Gold Corporation, vice president of Aber Resources (now Dominion Diamond Corp.), and as founder and chief executive officer of Stornoway Diamond Corp. Ms. Thomas graduated from the University of Toronto with a bachelor of science degree in geology. Her awards and recognition include being named one of Canada's Top 40 Under 40 by Caldwell Partners and *Report on Business* magazine, selected as one of Canada's top 100 most powerful women by WXN and being one of only four Canadians in 2008 to be named to the Forum of Young Global Leaders by the World Economic Forum.

Michael M. Wilson Alberta, Canada	Director since 2014 Independent	Michael Wilson is former president and chief executive officer of Agrium Inc. (now Nutrien Ltd.), a retail supplier of agricultural products and services and a wholesale producer and marketer of agricultural nutrients, a position he held from 2003 until his retirement in 2013. He had previously served as Agrium's executive vice president and chief operating officer. Mr. Wilson has significant experience in the petrochemical industry, serving as president of Methanex Corporation and holding various positions with increasing responsibility in North America and Asia with Dow Chemical Company. He has a bachelor's degree in chemical engineering from the University of Waterloo and currently serves on the boards of Air Canada and Celestica Inc.

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

(2) Audit Committee

(3) Governance Committee

(4) Human Resources and Compensation Committee

Executive Officers

The following individuals are the executive officers of Suncor as at February 27, 2023:

Name	Jurisdiction of Residence	Office
Kris Smith(1)	Alberta, Canada	Interim President and Chief Executive Officer
Alister Cowan(1)	Alberta, Canada	Chief Financial Officer
Bruno Francoeur	Alberta, Canada	Executive Vice President, Business & Operations
Jacqueline Moore	Alberta, Canada	Chief Legal Officer and General Counsel
Paul Gardner	Alberta, Canada	Chief People Officer
Shelley Powell	Alberta, Canada	Senior Vice President, E&P and In Situ
Arlene Strom	Alberta, Canada	Chief Sustainability Officer
Peter Zebedee	Alberta, Canada	Executive Vice President, Mining & Upgrading

(1) Effective April 3, 2023, Rich Kruger will be appointed President and Chief Executive Officer. Effective May 9, 2023, Kris Smith will assume the role of Chief Financial Officer and Executive Vice President of Corporate Development and Alister Cowan, the current Chief Financial Officer, plans to retire at the end of 2023.

All executive officers have held positions with Suncor over the past five years, with the exception of Peter Zebedee who, immediately prior to joining Suncor in 2022, was CEO of LNG Canada.

As at February 27, 2023, the directors and executive officers of Suncor as a group beneficially owned, or controlled or directed, directly or indirectly, 406,625 common shares of Suncor, which represents 0.03% of the outstanding common shares of Suncor. Inclusive of deferred share units, the total share ownership of Suncor's directors and executive officers as at February 27, 2023, is 1,163,759 common shares and units of Suncor (for the purpose of share ownership targets, deferred share units are included).

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

As at the date hereof, no director or executive officer of Suncor is or has been within the last 10 years a director, chief executive officer or chief financial officer of a company (including Suncor) that:

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

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

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

(a) is, or has been within the last 10 years, a director or executive officer of any company (including Suncor) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than Mr. Gladu who was an officer of A2A Rail, which obtained creditor protection under Canadian insolvency legislation that was initiated on June 18, 2021. Mr. Gladu ceased to be an officer of A2A Rail on June 2, 2021; or

(b) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

No director or executive officer of Suncor, or any of their respective personal holding companies, nor any shareholder holding a sufficient number of securities to affect materially the control of Suncor, has been subject to:

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

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

Conflicts of Interest

The directors and officers of Suncor may be directors or officers of entities that are in competition with or are customers or suppliers of Suncor or certain entities in which Suncor holds an equity investment. As such, these directors or officers may encounter conflicts of interest in the administration of their duties with respect to Suncor. Directors and officers of Suncor are required to disclose the existence of potential conflicts in accordance with Suncor's policies and in accordance with the CBCA.

Audit Committee Information

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

Composition of the Audit Committee

The Audit Committee is comprised of Ms. Bedient (Chair), Mr. Ashby, Mr. MacDonald and Ms. Mitchelmore. All members are independent and financially literate. The education and experience of each member that has led to the determination of financial literacy is described in the Directors and Executive Officers section of this AIF.

For the purpose of making appointments to the company’s Audit Committee, and in addition to the independence requirements, all directors nominated to the Audit Committee must meet the test of financial literacy as determined in the judgment of the Board of Directors. Also, at least one director so nominated must meet the requirements of being an Audit Committee Financial Expert (as defined below) as determined in the judgment of the Board of Directors. The Audit Committee Financial Experts on the Audit Committee are Ms. Bedient and Mr. MacDonald.

Financial Literacy

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

- The level of the person’s accounting or financial education, including whether the person has earned an advanced degree in finance or accounting;
- Whether the person is a professional accountant, or the equivalent, in good standing, and the length of time that the person actively has practiced as a professional accountant, or the equivalent;
- Whether the person is certified or otherwise identified as having accounting or financial experience by a recognized private body that establishes and administers standards in respect of such expertise, whether that person is in good standing with the recognized private body, and the length of time that the person has been actively certified or identified as having this expertise;
- Whether the person has served as a principal financial officer, controller or principal accounting officer of a company that, at the time the person held such position, was required to file reports pursuant to securities laws and, if so, for how long;
- The person’s specific duties while serving as a public accountant, auditor, principal financial officer, controller, principal accounting officer or position involving the performance of similar functions;
- The person’s level of familiarity and experience with all applicable laws and regulations regarding the preparation of financial statements that must be included in reports filed under securities laws;
- The level and amount of the person’s direct experience reviewing, preparing, auditing or analyzing financial statements that must be included in reports filed under provisions of securities laws;
- The person’s past or current membership on one or more audit committees of companies that, at the time the person held such membership, were required to file reports pursuant to provisions of securities laws;
- The person’s level of familiarity and experience with the use and analysis of financial statements of public companies; and

- Whether the person has any other relevant qualifications or experience that would assist him or her in understanding and evaluating the company's financial statements and other financial information and to make knowledgeable and thorough inquiries whether the financial statements fairly present the financial condition, results of operations and cash flows of the company in accordance with generally accepted accounting principles, and whether the financial statements and other financial information, taken together, fairly present the financial condition, results of operations and cash flows of the company.

Audit Committee Financial Expert

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

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

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

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

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

(e) an understanding of audit committee functions.

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

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

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

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

(d) other relevant experience.

Audit Committee Pre-Approval Policies for Non-Audit Services

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

Fees Paid to Auditors

Fees paid or payable to the company's auditors, KPMG LLP (Calgary, Canada), in 2022 and 2021 are as follows:

($ thousands)	2022	2021
Audit fees[1]	7,406	6,441
Audit-related fees	835	465
All other fees	241	—
Total	8,482	6,906

(1) 2021 audit fees have been restated to include $0.7 million related to Syncrude audit services and reflect Suncor assuming the role of operator on September 30, 2021.

Audit fees were paid, or are payable, for professional services rendered by the auditors for the audit of Suncor's annual financial statements, or services provided in connection with statutory and regulatory filings or engagements. Audit-related fees were paid for professional services rendered by the auditors for the review of quarterly financial statements and for the preparation of reports on specified procedures as they relate to audits of joint arrangements and attest services not required by statute or regulation. All other fees were advisory services around ESG. All services described beside the captions "audit fees", "audit-related fees" and "all other fees" were approved by the Audit Committee in compliance with paragraph (c)(7)(i) of Rule 2-01 of Regulation S-X under the *U.S. Securities and Exchange Act of 1934* , as amended (the Exchange Act). None of the fees described above were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Regulation S-X under the Exchange Act.

Legal Proceedings and Regulatory Actions

There are no legal proceedings in respect of which Suncor is or was a party, or in respect of which any of the company's property is or was the subject during the year ended December 31, 2022, nor are there any such proceedings known by the company to be contemplated, that involve a claim for damages exceeding 10% of the company's current assets. In addition, there have not been any (a) penalties or sanctions imposed against the company by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2022, (b) any other penalties or sanctions imposed by a court or regulatory body against the company that would likely be considered important to a reasonable investor in making an investment decision, or (c) settlement agreements entered into by the company before a court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2022.

Interests of Management and Others in Material Transactions

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

Transfer Agent and Registrar

The transfer agent and registrar for Suncor's common shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta; Montreal, Quebec; Toronto, Ontario; and Vancouver, British Columbia; and Computershare Trust Company N.A. in Canton, Massachusetts; Jersey City, New Jersey; and Louisville, Kentucky.

Material Contracts

During the year ended December 31, 2022, Suncor did not enter into any contracts, nor are there any contracts still in effect, that are material to the company's business, other than contracts entered into in the ordinary course of business, which are not required to be filed by Section 12.2 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

Interests of Experts

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

The company's independent auditors are KPMG LLP, Chartered Professional Accountants (KPMG). KPMG has confirmed with respect to the company that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations and also that they are independent accountants with respect to the company under all relevant U.S. professional and regulatory standards.

Disclosure Pursuant to the Requirements of the NYSE

As a Canadian issuer listed on the NYSE, Suncor is not required to comply with most of the NYSE's governance rules and instead may comply with Canadian requirements. As a foreign private issuer, the company is only required to comply with four of the NYSE's governance rules. These rules provide that (i) Suncor must have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act; (ii) the chief executive officer of Suncor must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE rules; (iii) Suncor must provide a brief description of any significant differences between the company's

corporate governance practices and those followed by U.S. companies listed under the NYSE; and (iv) Suncor must provide annual and, as required, written affirmations of compliance with applicable NYSE Corporate Governance Standards.

The company has disclosed in its 2023 management proxy circular, which is available on Suncor's website at www.suncor.com, significant areas in which the company does not comply with the NYSE Corporate Governance Standards. In certain instances, it is not required to obtain shareholder approval for material amendments to equity compensation plans under TSX requirements, while the NYSE requires shareholder approval of all equity compensation plans. Suncor, while in compliance with the independence requirements of applicable securities laws in Canada (specifically National Instrument 52-110 – *Audit Committees*) and the U.S. (specifically Rule 10A-3 of the Exchange Act), has not adopted, and is not required to adopt, the director independence standards contained in Section 303A.02 of the NYSE's Listed Company Manual, including with respect to its audit committee and compensation committee. The Board has not adopted, nor is it required to adopt, procedures to implement Section 303A.05(c)(iv) of the NYSE's Listed Company Manual in respect of compensation committee advisor independence. Except as described herein, the company is in compliance with the NYSE Corporate Governance Standards in all other significant respects.

Additional Information

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Suncor's securities, and securities authorized for issuance under equity compensation plans, where applicable, is contained in the company's most recent management proxy circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided in Suncor's 2022 audited Consolidated Financial Statements and in the annual 2022 MD&A.

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

Advisory – Forward-Looking Information and Non-GAAP Financial Measures

This AIF contains certain forward-looking statements and forward-looking information (collectively, forward-looking statements) within the meaning of applicable Canadian and U.S. securities laws and other information based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of information available at the time the statement was made and consider Suncor's experience and its perception of historical trends, including expectations and assumptions concerning: the accuracy of reserves estimates; the current and potential adverse impacts of the COVID-19 pandemic, including the status of the pandemic and future waves; commodity prices and interest and foreign exchange rates; the performance of assets and equipment; capital efficiencies and cost-savings; applicable laws and government policies; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour, services and infrastructure; the satisfaction by third parties of their obligations to Suncor; the development and execution of projects; and the receipt, in a timely manner, of regulatory and third-party approvals. All statements and information that address expectations or projections about the future, and statements and information about Suncor's strategy for growth, expected and future expenditures or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and the expected impact of future commitments are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects", "anticipates", "will", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", "continue", "should", "may", "potential", "future", "opportunity", "would", "forecast" and similar expressions.

Forward-looking statements in this AIF include references to:

Suncor's strategy, business plans and expectations about projects, the performance of assets, production volumes, and capital expenditures, including:

- *Expectations about the West White Rose Project, including the expectation that it would extend the life of the existing White Rose assets and the expectation that production will commence in the first half of 2026 and will extend the production life of the White Rose field, providing long-term value for the company;*
- *The aim, objectives and potential benefits of Suncor's clean energy investments, including Enerkem Inc., LanzaJet Inc., Svante Inc. and the Varennes Carbon Recycling facility, and Suncor's belief that these investments complement Suncor's existing product mix and demonstrate Suncor's involvement in the evolving global energy expansion;*
- *Suncor's strategic objective to become a net-zero GHG emissions company by 2050 and to substantially contribute to society's net-zero ambitions as well as Suncor's ambitious near-term goals of reducing emissions across its value chain and the plans and areas of focus that Suncor has to achieve these objectives and goals;*
- *Expectations about Terra Nova and the ALE Project, including the expectation that the ALE Project will extend production life of the Terra Nova field by approximately 10 years and provide many benefits to the Newfoundland and Labrador and Canadian economies in the form of taxes, royalties and employment and that the FPSO will return to production in the second quarter of 2023;*
- *Statements about Suncor's coke-fired boiler replacement program, including the expectation that it will provide steam generation, reduce the GHG emissions intensity associated with steam production at Oil Sands Base operations by approximately 25%, reduce GHG emissions in the province of Alberta by approximately 5.1Mt per year, the expectation that the excess electricity produced will be transmitted to Alberta's power grid and the expected*

benefits therefrom, and cost approximately $1.4 billion with an expected in-service date in late 2024;

- *Statements regarding the Pathways Alliance, including the goals, expectations regarding timing and the expected pathways the alliance will take to address GHG emissions;*
- *Suncor's expectation that the Northern Courier Pipeline will provide the eight Indigenous communities (which Suncor has partnered with) reliable income for decades;*
- *Expectations regarding the sale of the company's U.K. E&P portfolio for gross proceeds of approximately $1.2 billion, including a contingent consideration of approximately $338 million and the expectation that the sale will close in mid-2023;*
- *Expectations regarding the MLX-W and MLX-E programs, including that the MLX-E program will follow MLX-W development if economic conditions remain suitable, that the MLX-W program will sustain bitumen production levels at the Mildred Lake site after resource depletion at the North Mine and use existing mining and extraction facilities, and that MLX-W will achieve first oil in late 2025;*
- *Statements regarding the Fort Hills 3-year mine improvement plan including the expected impacts to production rates and operating costs;*
- *Suncor's expectation that the Sunbridge power asset will be fully decommissioned in 2023;*
- *The estimated cost of Suncor's remaining exploration work program commitment in Libya at December 31, 2022, of US$359 million;*
- *The expectation that the drilling of new well pairs and infill wells at Firebag and MacKay River will assist in maintaining production levels in future years;*
- *The potential for both development opportunities that may support future mining operations including interests in Base Mine Extension and Audet, as well as future in situ production to be supported at Meadow Creek, Lewis, OSLO, Gregoire, Chard and Kirby; and*
- *The expectation that turnaround maintenance will improve reliability and operational efficiency.*

Also:

- *Expectations (including with respect to timing), goals and plans around technologies, including autonomous haulage systems, permanent aquatic storage structures, expanding solvent SAGD, solvent dominated recovery process and, non-aqueous extraction;*
- *Statements about Suncor's reserves, including reserves volumes, estimates of future net revenues, commodity price forecasts, exchange and interest rate expectations, and production estimates;*
- *Significant development activities and costs anticipated to occur or be incurred in 2023, including those identified under the Future Development Costs table in the Statement of Reserves Data and Other Oil and Gas Information section of this AIF; Suncor's belief that internally generated cash flows, existing and future credit facilities, issuing commercial paper and, if needed, accessing capital markets will be sufficient to fund future development costs and that interest expense or other funding costs on their own would not make development of any property uneconomic; plans for the development of reserves; and the estimated value of work commitments;*

- *Estimated abandonment and reclamations costs;*
- *Nameplate capacities;*
- *Expectations about royalties and income taxes and their impact on Suncor;*
- *Expectations regarding tailings management plans and regulatory processes with respect thereto;*
- *Expectations regarding Suncor's share repurchase program and the NCIB;*
- *Expectations concerning the timing of negotiations for collective agreements;*
- *Anticipated effects of and responses to environmental laws and regulations, including climate change and GHG emissions laws and regulations, regulatory permits and Suncor's estimated compliance costs; and*
- *Expectations about changes to laws and the impact thereof.*

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

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

Factors that affect Suncor's Oil Sands segment include, but are not limited to, volatility in the prices for crude oil and other production, and the related impacts of fluctuating light/heavy and sweet/sour crude oil differentials; changes in the demand for refinery feedstock and diesel fuel, including the possibility that refiners that process the company's proprietary production will be closed, experience equipment failure or other accidents; Suncor's ability to operate its Oil Sands facilities reliably in order to meet production targets; the output of newly commissioned facilities, the performance of which may be difficult to predict during initial operations; Suncor's dependence on pipeline capacity and other logistical constraints, which may affect the company's ability to distribute products to market and which may cause the company to delay or cancel planned growth projects in the event of insufficient takeaway capacity; Suncor's ability to finance Oil Sands economic investment and asset sustainability and maintenance capital expenditures; the availability of bitumen feedstock for upgrading operations, which can be negatively affected by poor ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage, and in situ reservoir and equipment performance, or the unavailability of third-party bitumen; changes in operating costs, including the cost of labour, natural gas and other energy sources used in oil sands processes; and the company's ability to complete projects, including planned maintenance events, both on time and on budget, which could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Alberta's Wood Buffalo region and the surrounding area (including housing, roads and schools).

Factors that affect Suncor's Exploration and Production segment include, but are not limited to, volatility in crude oil and natural gas prices; operational risks and uncertainties associated with oil and gas activities, including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, and pollution and other environmental risks; adverse weather conditions, which could disrupt output from producing assets or impact drilling programs, resulting in increased costs and/or delays in bringing on new production; political, economic and socioeconomic risks associated with Suncor's foreign operations, including the unpredictability of operating in Libya due to ongoing political unrest; and market demand for mineral rights and producing properties, potentially leading to losses on disposition or increased property acquisition costs.

Factors that affect Suncor's Refining and Marketing segment include, but are not limited to, fluctuations in demand and supply for refined products that impact the company's margins; market competition, including potential new market entrants; the company's ability to reliably operate refining and marketing facilities to meet production or sales targets; and risks and uncertainties affecting construction or planned maintenance schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.

Additional risks, uncertainties and other factors that could influence the financial and operating performance of all of Suncor's operating segments and activities include, but are not limited to, changes in general economic, market and business conditions, such as commodity prices, interest rates and currency exchange rates (including as a result of demand and supply effects resulting from the COVID-19 pandemic and the actions of OPEC+); fluctuations in supply and demand for Suncor's products; the successful and timely implementation of capital projects, including growth projects and regulatory projects; risks associated with the development and execution of Suncor's projects and the commissioning and integration of new facilities; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; the risk that projects and initiatives intended to achieve cash flow growth and/or reductions in operating costs may not achieve the expected results in the time anticipated or at all; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; actions by government authorities, including the imposition or reassessment of, or changes to, taxes, fees, royalties, duties, tariffs, quotas and other government-imposed compliance costs and mandatory production curtailment orders and changes thereto; changes to laws and government policies that could impact the company's business, including environmental (including climate change), royalty and tax laws and policies; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to the company; the unavailability of, or outages to, third-party infrastructure that could cause disruptions to production or prevent the company from being able to transport its products; the occurrence of a protracted operational outage, a major safety or environmental incident, or unexpected events such as fires (including forest fires), equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; the potential for security breaches of Suncor's information technology and infrastructure by malicious persons or entities, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; security threats and terrorist or activist activities; the risk that competing business objectives may exceed Suncor's capacity to adopt and implement change; risks and uncertainties associated with obtaining regulatory, third-party and stakeholder approvals outside of Suncor's control for the company's operations, projects, initiatives, and exploration and development activities and the satisfaction of any conditions to approvals; the potential for disruptions to operations and construction projects as a result of Suncor's relationships with labour unions that represent employees at the company's facilities; the company's ability to find new oil and gas reserves that can be developed economically; the accuracy of Suncor's reserves and future production estimates; Suncor's ability to access capital markets at acceptable rates or to issue securities at acceptable prices; maintaining an optimal debt to cash flow ratio; the success of the company's risk management activities using derivatives and other financial instruments; the cost of compliance with current and future environmental laws, including climate change laws; risks relating to increased activism and public opposition to fossil fuels and oil sands; risks and uncertainties associated with closing a transaction for the purchase or sale of a business, asset or oil and gas property, including estimates of the final consideration to be paid or received; the ability of counterparties to comply with their obligations in a timely manner; risks associated with joint arrangements in which the company has an interest; risks associated with land claims and Indigenous consultation requirements; the risk that the company may be subject to litigation; the impact of technology and risks associated with developing and implementing new technologies; and the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering that is needed to reduce the margin of error and increase the level of accuracy. The foregoing important factors are not exhaustive.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements are discussed in further detail throughout this AIF and the company's annual 2022 MD&A including under the heading Risk Factors, and Form 40-F on file with Canadian securities commissions at www.sedar.com

and the SEC at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

The forward-looking statements contained in this AIF are made as of the date of this AIF. Except as required by applicable securities laws, we assume no obligation to update publicly or otherwise revise any forward-looking statements or the foregoing risks and assumptions affecting such forward-looking statements, whether as a result of new information, future events or otherwise.

Non-GAAP Financial Measures – Netback

Netback is a financial measure that is not prescribed by GAAP. Non-GAAP measures do not have any standardized meaning under GAAP and therefore are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. Netbacks are reconciled to GAAP measures in the Operating Metrics Reconciliation section of the Supplemental Financial and Operating Information within Suncor's Annual Report for the year ended December 31, 2022 and dated March 6, 2023.

Table of Contents

Schedule “A”
Audit Committee Mandate

The Audit Committee

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

Objectives

The Audit Committee assists the Board by:

- monitoring the effectiveness and integrity of the Corporation’s internal controls of Suncor’s business processes, including: financial and management reporting systems, internal control systems;
- monitoring and reviewing financial reports and other financial matters;
- selecting, monitoring and reviewing the independence and effectiveness of, and where appropriate replacing, subject to shareholder approval as required by law, external auditors, and ensuring that external auditors are ultimately accountable to the Board of Directors and to the shareholders of the Corporation;
- reviewing the effectiveness of the internal auditors, excluding the Operations Integrity Audit department, which is specifically within the mandate of the Environment, Health & Safety Committee (references throughout this mandate to “Internal Audit” shall not include the Operations Integrity Audit department); and
- approving on behalf of the Board of Directors certain financial matters as delegated by the Board, including the matters outlined in this mandate.

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

Constitution

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

Functions and Responsibilities

The Audit Committee has the following functions and responsibilities:

Internal Controls

1. Inquire as to the adequacy of the Corporation's system of internal controls of Suncor’s business processes, and review the evaluation of internal controls by Internal Auditors, and the evaluation of financial and internal controls by external auditors.
2. Review audits conducted of the Corporation’s Standards of Business Conduct-Compliance Program.

3. Establish procedures for the confidential submission by employees of complaints relating to any concerns with accounting, internal control, auditing or Standards of Business Conduct Code matters, and periodically review a summary of complaints and their related resolution.
4. Review the findings of any significant examination by regulatory agencies concerning the Corporation's financial matters.
5. Periodically review management's governance processes for information technology resources, to assess their effectiveness in addressing the integrity, the protection and the security of the Corporation's electronic information systems and records.
6. Review the management practices overseeing officers' expenses and perquisites.

External and Internal Auditors

7. Evaluate the performance of the external auditors and initiate and approve the engagement or termination of the external auditors, subject to shareholder approval as required by applicable law.
8. Review the audit scope and approach of the external auditors, and approve their terms of engagement and fees.
9. Review any relationships or services that may impact the objectivity and independence of the external auditor, including annual review of the auditor's written statement of all relationships between the auditor (including its affiliates) and the Corporation; review and approve all engagements for non-audit services to be provided by external auditors or their affiliates.
10. Review the external auditor's quality control procedures including any material issues raised by the most recent quality control review or peer review and any issues raised by a government authority or professional authority investigation of the external auditor, providing details on actions taken by the firm to address such issues.
11. Approve the appointment or termination of the VP Enterprise Risk and Audit, approve annually the performance assessment and resulting compensation of the VP Enterprise Risk & Audit as provided by the Chief Financial Officer. Periodically review the performance and effectiveness of the Internal Audit function including conformance with The Institute of Internal Auditors' International Standards for the Professional Practice of Internal Auditing and the Code of Ethics.
12. Approve the Internal Audit Department Charter, the annual Internal Audit schedule, as well as the Internal Audit budget and resource plan. Review the plans, activities, organizational structure, resource capacity and qualifications of the Internal Auditors, and monitor the department's independence.
13. Provide direct and unrestricted access by management, the Internal Auditors and the external auditors to the Board of Directors.

Financial Reporting and other Public Disclosure

14. Review the external auditor's management comment letter and management's responses thereto, and inquire as to any disagreements between management and external auditors or restrictions imposed by management on external auditors. Review any unadjusted differences brought to the attention of management by the external auditor and the resolution thereof.
15. Review with management and the external auditors the financial materials and other disclosure documents referred to in paragraph 16, including any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material to financial reporting including alternative treatments and their impacts.
16. Review and approve the Corporation's interim consolidated financial statements and accompanying management's discussion and analysis ("MD&A"). Review and make recommendations to the Board of Directors on approval of the Corporation's annual audited

financial statements and MD&A, Annual Information Form and Form 40-F. Review other material annual and quarterly disclosure documents or regulatory filings containing or accompanying audited or unaudited financial information.

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

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

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

Oil and Gas Reserves

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

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

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

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

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

Risk Management

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

Pension Plan

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

Security

25. Review on a summary basis any significant physical security management and strategies to address such risks.

Other Matters

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

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

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

Reporting to the Board

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

Approved by resolution of the Board of Directors on November 14, 2017

Schedule "B" – Suncor Energy Inc. Policy and Procedures for Pre-Approval of Audit and Non-Audit Services

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

I. Statement of Policy

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

II. Responsibility

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

III. Definitions

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

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

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

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

(ii) the performance of domestic and foreign statutory audits;

(iii) Attest services required by statute or regulation;

(iv) Internal control reviews; and

(v) Assistance with and review of documents filed with the Canadian Securities administrators, the Securities and Exchange Commission and other regulators having jurisdiction over Suncor and its subsidiaries, and responding to comments from such regulators;

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

"Audit-related services" include:

(i) employee benefit plan audits, including audits of employee pension plans;

(ii) due diligence related to mergers and acquisitions;

(iii) consultations and audits in connection with acquisitions, including evaluating the accounting treatment for proposed transactions;

(iv) internal control reviews;

(v) attest services not required by statute or regulation; and

(vi) consultations regarding financial accounting and reporting standards.

Non-financial operational audits are **not** "audit-related" services.

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

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

IV. General Policy

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

- All services to be provided by the independent auditor will require specific pre-approval by the Audit Committee. The Audit Committee will not approve engaging the independent auditor for services which can reasonably be classified as "tax services" or "all other services" unless a compelling business case can be made for retaining the independent auditor instead of another service provider.
- The Audit Committee will not provide pre-approval for services to be provided in excess of twelve months from the date of the pre-approval, unless the Audit Committee specifically provides for a different period.
- The Audit Committee has delegated authority to pre-approve services with an estimated cost not exceeding $100,000 in accordance with this Policy to the Chairman of the Audit Committee. The delegate member of the Audit Committee must report any pre-approval decision to the Audit Committee at its next meeting.
- The Chairman of the Audit Committee may delegate his authority to pre-approve services to another sitting member of the Audit Committee provided that the recipient has also been delegated the authority to act as Chairman of the Audit Committee in the Chairman's absence. A resolution of the Audit Committee is required to evidence the Chairman's delegation of authority to another Audit Committee member under this policy.
- The Audit Committee will, from time to time, but no less than annually, review and pre-approve the services that may be provided by the independent auditor.
- The Audit Committee must establish pre-approval fee levels for services provided by the independent auditor on an annual basis. On at least a quarterly basis, the Audit Committee will be provided with a detailed summary of fees paid to the independent auditor and the nature of the services provided, and a forecast of fees and services that are expected to be provided during the remainder of the fiscal year.
- The Audit Committee will **not** approve engaging the independent auditor to provide any prohibited non-audit services as set forth in Appendix A.
- The Audit Committee shall evidence their pre-approval for services to be provided by the independent auditor as follows:

(a) In situations where the Chairman of the Audit Committee pre-approves work under his delegation of authority, the Chairman will evidence his pre-approval by signing and dating

the pre-approval request form, attached as Appendix B. If it is not practicable for the Chairman to complete the form and transmit it to the Company prior to engagement of the independent audit, the Chairman may provide verbal or email approval of the engagement, followed up by completion of the request form at the first practical opportunity.

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

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

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

(b) specify the particular services to be provided;

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

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

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

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

V. Responsibilities of External Auditors

To support the independence process, the independent auditors will:

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

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

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

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

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

In addition, the external auditors will:

(f) Provide regular, detailed fee reporting including balances in the “Work in Progress” account;

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

VI. Disclosures

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

Approved and Accepted April 28, 2004

Appendix A – Prohibited Non-Audit Services

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

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

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

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

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

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

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

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

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

Human resources. Any of the following:

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

Broker-dealer, investment adviser or investment banking services. Acting as a broker-dealer (registered or unregistered), promoter, or underwriter, on behalf of Suncor, making investment decisions on behalf of Suncor or otherwise having discretionary authority over Suncor's investments, executing a transaction to

buy or sell Suncor's investment, or having custody of Suncor's assets, such as taking temporary possession of securities purchased by Suncor.

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

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

Table of Contents

Appendix B – Pre-Approval Request Form

NATURE OF WORK	ESTIMATED FEES (Cdn$)
Total	

Date Signature

Schedule “C” – Form 51-101F2 Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

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

1. We have evaluated the Company’s reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs.

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the “COGE Handbook”) maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2022, and identifies the respective portions thereof that we have evaluated and reported on to the Company’s management and board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, $ millions)			
			Audited	Evaluated	Reviewed	Total
GLJ Ltd.	December 31, 2022	Oil Sands In Situ, Canada	—	28,460	—	28,460
GLJ Ltd.	December 31, 2022	Oil Sands Mining, Canada	—	32,601	—	32,601
GLJ Ltd.	December 31, 2022	East Coast Canada, Newfoundland Offshore, Canada	—	7,827	—	7,827
GLJ Ltd.	December 31, 2022	Offshore, United Kingdom	—	2,452	—	2,452
			—	71,340	—	71,340

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

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

EXECUTED as to our report referred to above:

GLJ Ltd., Calgary, Alberta, Canada, March 6, 2023

“Tim R. Freeborn”

Tim R. Freeborn, P.Eng.
Vice President

Schedule “D” – Form 51-101F3 Report of Management and Directors on Reserves Data and Other Information

Management of Suncor Energy Inc. (the “Company”) are responsible for the preparation and disclosure of information with respect to the Company’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

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

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

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

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

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

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

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

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

(c) the content and filing of this report.

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

“*Kris P. Smith*”

KRIS P. SMITH
Interim President and Chief Executive Officer

“Alister Cowan”

ALISTER COWAN
Chief Financial Officer

“*Michael M. Wilson*”

MICHAEL M. WILSON
Chair of the Board of Directors

“*Patricia M. Bedient*”

PATRICIA M. BEDIENT
Chair of the Audit Committee

March 6, 2023



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

Exhibit 99-2

Audited Consolidated Financial Statements and Notes - Table of Contents

MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL REPORTING	2
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING	3
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM (AUDIT FIRM ID: 85)	4
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)	8
CONSOLIDATED BALANCE SHEETS	9
CONSOLIDATED STATEMENTS OF CASH FLOWS	10
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY	11
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS	12
1. REPORTING ENTITY AND DESCRIPTION OF THE BUSINESS	12
2. BASIS OF PREPARATION	12
3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES	12
4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS	20
5. NEW IFRS STANDARDS	22
6. SEGMENTED INFORMATION	23
7. OTHER INCOME	26
8. OPERATING, SELLING AND GENERAL EXPENSE	26
9. FINANCING EXPENSES	26
10. INCOME TAXES	27
11. EARNINGS (LOSS) PER COMMON SHARE	28
12. CASH AND CASH EQUIVALENTS	29
13. SUPPLEMENTAL CASH FLOW INFORMATION	29
14. INVENTORIES	30
15. PROPERTY, PLANT AND EQUIPMENT	30
16. ASSET IMPAIRMENTS AND TRANSACTIONS	31
17. RIGHT-OF-USE ASSETS AND LEASES	34
18. EXPLORATION AND EVALUATION ASSETS	36
19. OTHER ASSETS	36
20. GOODWILL AND OTHER INTANGIBLE ASSETS	36
21. DEBT AND CREDIT FACILITIES	37
22. OTHER LONG TERM LIABILITIES	40
23. PENSIONS AND OTHER POST RETIREMENT BENEFITS	40
24. PROVISIONS	43
25. SHARE CAPITAL	44
26. SHARE BASED COMPENSATION	46
27. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT	48
28. CAPITAL STRUCTURE FINANCIAL POLICIES	52
29. JOINT ARRANGEMENTS	54
30. SUBSIDIARIES	55
31. RELATED PARTY DISCLOSURES	56
32. COMMITMENTS, CONTINGENCIES AND GUARANTEES	56
33. ASSETS HELD FOR SALE	57

Table of Contents

Management's Statement of Responsibility for Financial Reporting

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

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. They include certain amounts that are based on estimates and judgments.

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

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

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



Kris Smith
Interim President and Chief Executive Officer



Alister Cowan
Chief Financial Officer

March 6, 2023

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

Management's Report on Internal Control Over Financial Reporting

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

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

3. Management has assessed the effectiveness of the company's internal control over financial reporting as at December 31, 2022, and has concluded that such internal control over financial reporting was effective as of that date. In addition, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as at December 31, 2022. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

4. The effectiveness of the company's internal control over financial reporting as at December 31, 2022, has been audited by KPMG LLP, independent auditor, as stated in their report which appears herein.



Kris Smith
Interim President and Chief Executive Officer



Alister Cowan
Chief Financial Officer

March 6, 2023

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Suncor Energy Inc.

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of Suncor Energy Inc. (the Company) as of December 31, 2022 and 2021, the related consolidated statements of comprehensive income, changes in equity, and cash flows for each of the years in the two-year period ended December 31, 2022, and the related notes (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and its financial performance and its cash flows for each of the years in the two-year period ended December 31, 2022, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022 based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to

permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Evaluation of the assessment of indicators of impairment loss or reversal related to Oil Sands and Exploration and Production property, plant and equipment

As discussed in Note 3(m) to the consolidated financial statements, when circumstances indicate that a cash generating unit ("CGU") may be impaired or a previous impairment reversed, the Company compares the carrying amount of the CGU to its recoverable amount. Quarterly, the Company analyzes indicators of impairment loss or reversal ("impairment indicators"), such as significant increases or decreases in forecasted production volumes (which include assumptions related to proved and probable oil reserves), commodity prices, capital expenditures and operating costs (collectively, "reserve assumptions"). The estimate of reserve assumptions requires the expertise of independent qualified reserves evaluators. The Company engages independent qualified reserves evaluators to evaluate the Company's proved and probable oil reserves. The carrying amount of the Company's Oil Sands and Exploration and Production property, plant and equipment balance as of December 31, 2022 was $52,494 million.

We identified the evaluation of the assessment of indicators of impairment loss or reversal related to the Oil Sands and Exploration and Production property, plant and equipment as a critical audit matter. A high degree of subjective auditor judgment was required to evaluate the reserve assumptions used by the Company in their assessment.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to the Company's assessment of indicators of impairment loss or reversal, including controls related to the reserve assumptions. We evaluated the Company's reserve assumptions by comparing the current year externally evaluated proved and probable oil reserves to historical results. We compared the Company's current year actual production volumes, operating costs and capital expenditures to those respective assumptions used in the prior year externally evaluated proved and probable oil reserves to assess the Company's ability to accurately forecast. We evaluated the Company's future commodity price estimates by comparing to a number of publicly available external price curves for the same benchmark pricing. We evaluated the competence, capabilities, and objectivity of the Company's independent qualified reserves evaluators engaged by the Company, who evaluated the proved and probable oil reserves. We evaluated the methodology used by the independent reservoir engineering specialists to evaluate proved and probable oil reserves for compliance with regulatory standards.

Assessment of the impairment reversal of the White Rose cash generating unit

As discussed in note 16 to the consolidated financial statements, the Company identified an indicator of impairment reversal at June 30, 2022 for the White Rose cash generating unit ("CGU") and performed an impairment reversal test to determine the recoverable amount of the CGU based on the fair value less cost of disposal. The estimated recoverable amount of the CGU

involves numerous assumptions, including forecasted production volumes, commodity prices, royalty rates, capital expenditures ("forecasted cash flow assumptions"), and discount rate.

We identified the assessment of the impairment reversal of the White Rose CGU as a critical audit matter. A high degree of subjective auditor judgment was required in evaluating the Company's forecasted cash flow and discount rate assumptions as minor changes to these assumptions could have had a significant effect on the Company's calculation of the recoverable amount of the CGU. A high degree of subjective auditor judgement was also required to evaluate the externally evaluated proved and probable oil reserves which were used to assess the Company's forecasted cash flow assumptions. Additionally, the evaluation of the impairment reversal of the White Rose CGU required involvement of valuation professionals with specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to the Company's determination of the recoverable amount of the CGU, including controls related to determination of the forecasted cash flow assumptions and discount rate. We performed sensitivity analyses over the discount rate and forecasted commodity price assumptions to assess the impact of those assumptions on the Company's determination of the recoverable amount of the CGU. We evaluated the Company's future commodity price estimates by comparing to a number of publicly available external price curves for the same benchmark pricing. We evaluated the forecasted production volumes and capital expenditure assumptions used in the impairment test by comparing to the current year externally evaluated proved and probable oil reserves as well as to historical results. We evaluated the forecasted royalty rate assumptions used in the impairment test by comparing to the current year externally evaluated proved and probable oil reserves as well as the revised royalty agreement with the provincial government. We assessed differences between management's forecasted cash flow assumptions and the externally evaluated proved and probable oil reserves by comparing to recent historical results and comparable CGUs. We compared the Company's current year actual production volumes, royalty rates and capital expenditures to those respective assumptions used in the prior year externally evaluated proved and probable oil reserves to assess the Company's ability to accurately forecast. We evaluated the competence, capabilities and objectivity of the independent qualified reserves evaluators engaged by the Company, who evaluated the proved and probable oil reserves. We evaluated the methodology used by independent qualified reserves evaluators to evaluate proved and probable oil reserves for compliance with regulatory standards. We involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the Company's CGU discount rate, by comparing the inputs against publicly available market data for comparable entities and assessing the resulting discount rate
- evaluating the Company's estimate of recoverable amount of the CGU by comparing to publicly available market data and valuation metrics for comparable entities.

Assessment of the impairment of the Fort Hills cash generating unit

As discussed in note 16 to the consolidated financial statements, the Company identified an indicator of impairment at September 30, 2022 for the Fort Hills cash generating unit ("CGU") and performed an impairment test to determine the recoverable amount of the CGU based on the fair value less cost of disposal. The estimated recoverable amount of the CGU involves numerous assumptions, including forecasted production volumes, commodity prices (including foreign exchange rates), operating costs ("forecasted cash flow assumptions"), and discount rate.

We identified the assessment of the impairment of the Fort Hills CGU as a critical audit matter. A high degree of subjective auditor judgment was required in evaluating the Company's forecasted cash flow and discount rate assumptions as minor changes to these assumptions could have had a significant effect on the Company's calculation of the recoverable amount of the CGU. A high degree of subjective auditor judgement was also required to evaluate the externally evaluated proved and probable oil reserves which were used to assess the Company's forecasted cash flow assumptions. Additionally, the evaluation of the impairment of the Fort Hills CGU required involvement of valuation professionals with specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to the Company's determination of the recoverable amount of the CGU, including controls related to determination of the forecasted cash flow assumptions and discount rate. We performed sensitivity analyses over the discount rate and forecasted commodity price assumptions to assess the impact of those assumptions on the Company's determination of the recoverable amount of the CGU. We evaluated the Company's future commodity price (including foreign exchange rate) estimates by comparing to a number of publicly available external price curves for the same benchmark pricing. We evaluated the forecasted production volumes and operating cost assumptions used in the impairment test by comparing to the current year externally evaluated proved and probable oil reserves as well as to historical results. We assessed differences between management's forecasted cash flow assumptions and the externally evaluated proved and probable oil reserves by comparing to recent historical results and comparable CGUs. We compared the Company's current year actual production volumes and operating costs to those respective assumptions used in the prior year externally evaluated proved and probable oil reserves to assess the Company's ability to accurately forecast. We evaluated the competence, capabilities and objectivity of the independent qualified reserves evaluators engaged by the Company, who evaluated the proved and probable oil reserves. We evaluated the methodology used by independent qualified reserves evaluators to evaluate proved and probable oil reserves for compliance with regulatory standards. We involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the Company's CGU discount rate, by comparing the inputs against publicly available market data for comparable entities and assessing the resulting discount rate
- evaluating the Company's estimate of recoverable amount of the CGU by comparing to publicly available market data and valuation metrics for comparable entities.

Chartered Professional Accountants

We have served as the Company's auditor since 2019.

Calgary, Canada
March 6, 2023

Table of Contents

Consolidated Statements of Comprehensive Income

For the years ended December 31 ($ millions)	Notes	2022	2021
Revenues and Other Income			
Operating revenues, net of royalties	6	**58 336**	39 132
Other income (loss)	7	**131**	(31)
		58 467	39 101
Expenses			
Purchases of crude oil and products		**20 775**	13 791
Operating, selling and general	8 and 26	**12 807**	11 366
Transportation and distribution		**1 671**	1 479
Depreciation, depletion, amortization and impairment	15 and 16	**8 786**	5 850
Exploration		**56**	47
Loss (gain) on disposal of assets	16	**45**	(257)
Financing expenses	9	**2 011**	1 255
		46 151	33 531
Earnings before Income Taxes		**12 316**	5 570
Income Tax Expense (Recovery)			
Current	10	**4 229**	1 395
Deferred	10 and 16	**(990)**	56
		3 239	1 451
Net Earnings		**9 077**	4 119
Other Comprehensive Income			
Items That May be Subsequently Reclassified to Earnings:			
Foreign currency translation adjustment		**160**	(63)
Items That Will Not be Reclassified to Earnings:			
Actuarial gain on employee retirement benefit plans, net of income taxes		**838**	856
Other Comprehensive Income		**998**	793
Total Comprehensive Income		**10 075**	4 912
Per Common Share (dollars)	11		
Net earnings – basic		**6.54**	2.77
Net earnings – diluted		**6.53**	2.77
Cash dividends		**1.88**	1.05

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

Table of Contents

Consolidated Balance Sheets

($ millions)	Notes	December 31 2022	December 31 2021
Assets			
Current assets			
Cash and cash equivalents	12	**1 980**	2 205
Accounts receivable		**6 068**	4 534
Inventories	14	**5 058**	4 110
Income taxes receivable		**244**	128
Assets held for sale	33	**1 186**	-
Total current assets		**14 536**	10 977
Property, plant and equipment, net	15 - 17	**62 654**	65 546
Exploration and evaluation	18	**1 995**	2 226
Other assets	19	**1 766**	1 307
Goodwill and other intangible assets	20	**3 586**	3 523
Deferred income taxes	10	**81**	160
Total assets		**84 618**	83 739
Liabilities and Shareholders' Equity			
Current liabilities			
Short-term debt	21	**2 807**	1 284
Current portion of long-term debt	21	**-**	231
Current portion of long-term lease liabilities	21	**317**	310
Accounts payable and accrued liabilities		**8 167**	6 503
Current portion of provisions	24	**564**	779
Income taxes payable		**484**	1 292
Liabilities associated with assets held for sale	33	**530**	-
Total current liabilities		**12 869**	10 399
Long-term debt	21	**9 800**	13 989
Long-term lease liabilities	21	**2 695**	2 540
Other long-term liabilities	22	**1 642**	2 180
Provisions	24	**9 800**	8 776
Deferred income taxes	10 and 16	**8 445**	9 241
Equity		**39 367**	36 614
Total liabilities and shareholders' equity		**84 618**	83 739

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

Approved on behalf of the Board of Directors:



Michael Wilson
Director



Patricia M. Bedient
Director

March 6, 2023

Table of Contents

Consolidated Statements of Cash Flows

For the years ended December 31 ($ millions)	Notes	2022	2021
Operating Activities			
Net earnings		**9 077**	4 119
Adjustments for:			
Depreciation, depletion, amortization and impairment		**8 786**	5 850
Deferred income tax (recovery) expense	10 and 16	**(990)**	56
Accretion	9	**316**	304
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	9	**729**	(113)
Change in fair value of financial instruments and trading inventory		**(38)**	(13)
Loss (gain) on disposal of assets	16	**45**	(257)
Loss on extinguishment of long-term debt	9 and 21	**32**	80
Share-based compensation	26	**328**	205
Settlement of decommissioning and restoration liabilities	24	**(314)**	(263)
Other		**130**	289
(Increase) decrease in non-cash working capital	13	**(2 421)**	1 507
Cash flow provided by operating activities		**15 680**	11 764
Investing Activities			
Capital and exploration expenditures		**(4 987)**	(4 555)
Capital expenditures on assets held for sale	33	**(133)**	-
Proceeds from disposal of assets	16	**315**	335
Other investments and acquisitions		**(36)**	(28)
Decrease in non-cash working capital	13	**52**	271
Cash flow used in investing activities		**(4 789)**	(3 977)
Financing Activities			
Net increase (decrease) in short-term debt		**1 473**	(2 256)
Repayment of long-term debt	21	**(5 128)**	(2 451)
Issuance of long-term debt		**-**	1 423
Lease liability payments		**(329)**	(325)
Issuance of common shares under share option plans		**496**	8
Repurchase of common shares	25	**(5 135)**	(2 304)
Distributions relating to non-controlling interest		**(9)**	(9)
Dividends paid on common shares		**(2 596)**	(1 550)
Cash flow used in financing activities		**(11 228)**	(7 464)
(Decrease) Increase in Cash and Cash Equivalents		**(337)**	323
Effect of foreign exchange on cash and cash equivalents		**112**	(3)
Cash and cash equivalents at beginning of year		**2 205**	1 885
Cash and Cash Equivalents at End of Year		**1 980**	2 205
Supplementary Cash Flow Information			
Interest paid		**973**	980
Income taxes paid (received)		**4 737**	(532)

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

Table of Contents

Consolidated Statements of Changes in Equity

($ millions)	Notes	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income	Retained Earnings	Total	Number of Common Shares (thousands)
At December 31, 2020		25 144	591	877	9 145	35 757	1 525 151
Net earnings		-	-	-	4 119	4 119	-
Foreign currency translation adjustment		-	-	(63)	-	(63)	-
Actuarial gain on employee retirement benefit plans, net of income taxes of $277	23	-	-	-	856	856	-
Total comprehensive (loss) income		-	-	(63)	4 975	4 912	-
Issued under share option plans		8	-	-	-	8	245
Common shares forfeited		-	-	-	-	-	(186)
Repurchase of common shares for cancellation	25	(1 382)	-	-	(922)	(2 304)	(83 959)
Change in liability for share purchase commitment	25	(120)	-	-	(110)	(230)	-
Share-based compensation	26	-	21	-	-	21	-
Dividends paid on common shares		-	-	-	(1 550)	(1 550)	-
At December 31, 2021		23 650	612	814	11 538	36 614	1 441 251
Net earnings		**-**	**-**	**-**	**9 077**	**9 077**	**-**
Foreign currency translation adjustment		**-**	**-**	**160**	**-**	**160**	**-**
Actuarial gain on employee retirement benefit plans, net of income taxes of $264	23	**-**	**-**	**-**	**838**	**838**	**-**
Total comprehensive income		**-**	**-**	**160**	**9 915**	**10 075**	**-**
Issued under share option plans		**570**	**(58)**	**-**	**-**	**512**	**13 158**
Common shares forfeited		**-**	**-**	**-**	**-**	**-**	**(30)**
Repurchase of common shares for cancellation	25	**(1 947)**	**-**	**-**	**(3 188)**	**(5 135)**	**(116 908)**
Change in liability for share purchase commitment	25	**(16)**	**-**	**-**	**(104)**	**(120)**	**-**
Share-based compensation	26	**-**	**17**	**-**	**-**	**17**	**-**
Dividends paid on common shares		**-**	**-**	**-**	**(2 596)**	**(2 596)**	**-**
At December 31, 2022		**22 257**	**571**	**974**	**15 565**	**39 367**	**1 337 471**

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

Table of Contents

Notes to the Consolidated Financial Statements

1. Reporting Entity and Description of the Business

Suncor Energy Inc. (Suncor or the company) is an integrated energy company headquartered in Calgary, Alberta, Canada. Suncor's operations include oil sands development, production and upgrading; offshore oil and gas; petroleum refining in Canada and the U.S.; and the company's Petro-Canada retail and wholesale distribution networks (including Canada's Electric Highway™, a coast-to-coast network of fast-charging electric vehicle stations). Suncor is developing petroleum resources while advancing the transition to a low-emissions future through investments in power, renewable fuels and hydrogen. Suncor also conducts energy trading activities focused principally on the marketing and trading of crude oil, natural gas, byproducts, refined products and power. Suncor has been recognized for its performance and transparent reporting on the Dow Jones Sustainability World Index, FTSE4Good Index and CDP. Suncor's common shares (symbol: SU) are listed on the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE).

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

2. Basis of Preparation

(a) Statement of Compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

Suncor's accounting policies are based on IFRS issued and outstanding for all periods presented in these consolidated financial statements. These consolidated financial statements were approved by the Board of Directors on March 6, 2023.

(b) Basis of Measurement

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

(c) Functional Currency and Presentation Currency

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

(d) Use of Estimates, Assumptions and Judgments

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

3. Summary of Significant Accounting Policies

(a) Principles of Consolidation

The company consolidates its interests in entities it controls. Control comprises the power to govern an entity's financial and operating policies to obtain benefits from its activities, and is a matter of judgment. All intercompany balances and transactions are eliminated on consolidation.

(b) Joint Arrangements

Joint arrangements represent arrangements in which two or more parties have joint control established by a contractual agreement. Joint control only exists when decisions about the activities that most significantly affect the returns of the investee are unanimous. Joint arrangements can be classified as either a joint operation or a joint venture. The classification

of joint arrangements requires judgment. In determining the classification of its joint arrangements, the company considers the contractual rights and obligations of each investor and whether the legal structure of the joint arrangement gives the entity direct rights to the assets and obligations for the liabilities.

Where the company has rights to the assets and obligations for the liabilities of a joint arrangement, such arrangement is classified as a joint operation and the company's proportionate share of the joint operation's assets, liabilities, revenues and expenses are included in the consolidated financial statements, on a line-by-line basis.

Where the company has rights to the net assets of an arrangement, such arrangement is classified as a joint venture and accounted for using the equity method of accounting. Under the equity method, the company's initial investment is recognized at cost and subsequently adjusted for the company's share of the joint venture's income or loss, less distributions received.

(c) Investments in Associates

Associates are entities for which the company has significant influence, but not control or joint control over the financial and operational decisions. Investments in associates are accounted for using the equity method of accounting and are initially recognized at cost and adjusted thereafter for the change in the company's share of the investee's profit or loss and Other Comprehensive Income (OCI) less distributions received until the date that significant influence ceases.

(d) Foreign Currency Translation

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

In preparing the company's consolidated financial statements, the financial statements of each entity are translated into Canadian dollars. The assets and liabilities of foreign operations are translated into Canadian dollars at exchange rates as at the balance sheet date. Revenues and expenses of foreign operations are translated into Canadian dollars using foreign exchange rates that approximate those on the date of the underlying transaction. Foreign exchange differences are recognized in OCI.

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

(e) Revenues

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products, refined petroleum products and power represent the company's contractual arrangements with customers. Revenue is recorded when control passes to the customer, in accordance with specified contract terms. All operating revenue is earned at a point in time and is based on the consideration that the company expects to receive for the transfer of the goods to the customer. Revenues are usually collected in the month following delivery except retail gasoline, diesel and ancillary products, which are due upon delivery and, accordingly, the company does not adjust consideration for the effects of a financing component.

Revenue from oil and natural gas production is recorded net of royalty expense.

International operations conducted pursuant to Production Sharing Contracts (PSCs) are reflected in the consolidated financial statements based on the company's working interest. Each PSC establishes the exploration, development and operating costs the company is required to fund and establishes specific terms for the company to recover these costs and to share in the production profits. Cost recovery is generally limited to a specified percentage of production during each fiscal year (Cost Recovery Oil). Any Cost Recovery Oil remaining after costs have been recovered is referred to as Excess Petroleum and is shared between the company and the respective government. Assuming collection is reasonably assured, the company's share of Cost Recovery Oil and Excess Petroleum are reported as revenue when the sale of product to a third party occurs. Revenue also includes income taxes paid on the company's behalf by government joint partners.

(f) Cash and Cash Equivalents

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

(g) Inventories

Inventories of crude oil and refined products, other than inventories held for trading purposes, are valued at the lower of cost, using the first-in, first-out method, and net realizable value. Cost of inventory consists of purchase costs, direct production costs, direct overhead and depreciation, depletion and amortization. Materials and supplies are valued at the lower of average cost and net realizable value.

Inventories held for trading purposes are carried at fair value less costs to sell and any changes in fair value are recognized in Other Income within the respective reporting segment to which the trading activity relates.

(h) Assets Held for Sale

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

(i) Exploration and Evaluation Assets

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

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

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

(j) Property, Plant and Equipment

Property, Plant and Equipment are initially recorded at cost.

The costs to acquire developed or producing oil and gas properties, and to develop oil and gas properties, including completing geological and geophysical surveys and drilling development wells, and the costs to construct and install development infrastructure, such as wellhead equipment, well platforms, well pairs, offshore platforms, subsea structures and an estimate of asset retirement costs, are capitalized as oil and gas properties within Property, Plant and Equipment.

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

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

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

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

(k) Depreciation, Depletion and Amortization

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

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

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

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

Oil sands upgraders, extraction plants and mine facilities	20 to 40 years
Oil sands mine equipment	5 to 15 years
Oil sands in situ processing facilities	30 years
Power generation and utility plants	30 to 40 years
Refineries and other processing plants	20 to 40 years
Marketing and other distribution assets	10 to 40 years

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

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

Right-of-use assets within Property, Plant and Equipment are depreciated on a straight-line basis over the shorter of the estimated useful life of the right-of-use asset or the lease term.

(l) Goodwill and Other Intangible Assets

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

Other intangible assets include acquired customer lists, brand value and certain software costs.

Goodwill and brand value have indefinite useful lives and are not subject to amortization. Customer lists are amortized over their expected useful lives, which range from five to 10 years. Software costs are amortized over their expected useful lives, which range from five to six years. Expected useful lives of other intangible assets are reviewed on an annual basis.

(m) Impairment of Assets

Non-Financial Assets

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

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

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

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

Financial Assets

At each reporting date, the company assesses the expected credit losses associated with its financial assets measured at amortized cost. Expected credit losses are measured as the difference between the cash flows that are due to the company and the cash flows that the company expects to receive, discounted at the effective interest rate determined at initial recognition. For trade accounts receivables, the company applies the simplified approach permitted by IFRS 9 *Financial Instruments*, which requires lifetime expected credit losses to be recognized from initial recognition of the receivables. To measure expected credit losses, accounts receivables are grouped based on the number of days the receivables have been outstanding and the internal credit assessments of the customers. Credit risk for longer term receivables is assessed based on an external credit rating of the counterparty. For longer term receivables with credit risk that has not increased significantly since the date of recognition, the company measures the expected credit loss as the twelve-month expected credit loss. Expected credit losses are recognized in net earnings.

(n) Provisions

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

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

(o) Income Taxes

The company follows the liability method of accounting for income taxes whereby deferred income taxes are recorded for the effect of differences between the accounting and income tax basis of an asset or liability. Deferred income tax assets and liabilities are measured using enacted or substantively enacted income tax rates as at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Changes to these balances are recognized in net earnings or in Other Comprehensive Income in the period they occur. Investment tax credits are recorded as a reduction to the related expenditures.

The company recognizes the impact of a tax filing position when it is probable, based on the technical merits, that the position will be sustained upon audit. If it is determined a tax filing position is not considered probable, the company assesses the possible outcomes and their associated probabilities and records a tax provision based on the best estimate of the amount of tax payable.

(p) Pensions and Other Post-Retirement Benefits

The company sponsors defined benefit pension plans, defined contribution pension plans and other post-retirement benefits.

The cost of pension benefits earned by employees in the defined contribution pension plan is expensed as incurred. The cost of defined benefit pension plans and other post-retirement benefits are actuarially determined using the projected unit credit method based on present pay levels and management's best estimates of demographic and financial assumptions.

The liability recognized on the balance sheet is the present value of the defined benefit obligations less the fair value of plan assets. The value of plan assets is limited to the total of unrecognized past service cost and the present value of the economic benefits available in the form of refunds from the plan or reductions in future contributions to the plan ("effect of the asset ceiling"). Any surplus is immediately recognized in Other Comprehensive income. In addition, a minimum liability is recognized when the statutory minimum funding requirement for past service exceeds the economic benefits available in the form of refunds from the plan or reductions in future contributions to the plan.

Pension benefits earned during the current year are recorded in Operating, Selling and General expense. Interest costs on the net unfunded obligation are recorded in Financing Expense. Any actuarial gains or losses related to the plan assets and the defined benefit obligation, as well as the change in the asset ceiling and any minimum liability, are recognized immediately through Other Comprehensive Income and transferred directly to Retained Earnings.

(q) Share-Based Compensation Plans

Under the company's share-based compensation plans, share-based awards may be granted to executives, employees and non-employee directors. Compensation expense is recorded in Operating, Selling and General expense.

Share-based compensation awards that settle in cash or have the option to settle in cash or shares are accounted for as cash-settled plans. These are measured at fair value each reporting period using the Black-Scholes options pricing model. The expense is recognized over the vesting period, with a corresponding adjustment to the outstanding liability. When awards are surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the options are recorded to Share Capital.

Stock options that give the holder the right to purchase common shares are accounted for as equity-settled plans. The expense is based on the fair value of the options at the time of grant using the Black-Scholes options pricing model and is recognized over the vesting periods of the respective options. A corresponding increase is recorded to Contributed Surplus. Consideration paid to the company on exercise of options is credited to Share Capital and the associated amount in Contributed Surplus is reclassified to Share Capital.

(r) Financial Instruments

The company classifies its financial instruments into one of the following categories: fair value through profit or loss (FVTPL), fair value through other comprehensive income, or at amortized cost. This determination is made at initial recognition. All financial instruments are initially recognized at fair value on the balance sheet, net of any transaction costs except for financial

instruments classified as FVTPL, where transaction costs are expensed as incurred. Subsequent measurement of financial instruments is based on their classification. The company classifies its derivative financial instruments and certain investments as FVTPL, cash and cash equivalents and accounts receivable as financial assets at amortized cost, and accounts payable and accrued liabilities, debt, and other long-term liabilities as financial liabilities at amortized cost.

In circumstances where the company consolidates a subsidiary in which there are other owners with a non-controlling interest and the subsidiary has a non-discretionary obligation to distribute cash based on a predetermined formula to the non-controlling owners, the non-controlling interest is classified as a financial liability rather than equity in accordance with IAS 32 *Financial Instruments: Presentation*. The non-controlling interest liability is classified as an amortized cost liability and is presented within Other Long-Term Liabilities. The balance is accreted based on current period interest expense recorded using the effective interest method and decreased based on distributions made to the non-controlling owners.

The company uses derivative financial instruments, such as physical and financial contracts, either to manage certain exposures to fluctuations in interest rates, commodity prices and foreign exchange rates, as part of its overall risk management program. Earnings impacts from derivatives used to manage a particular risk are reported as part of Other Income in the related reporting segment.

Certain physical commodity contracts, when used for trading purposes, are deemed to be derivative financial instruments for accounting purposes. Physical commodity contracts entered into for the purpose of receipt or delivery in accordance with the company's expected purchase, sale or usage requirements are not considered to be derivative financial instruments and are accounted for as executory contracts.

Derivatives embedded in other financial instruments or other host contracts are recorded as separate derivatives when their risks and characteristics are not closely related to those of the host contract.

(s) Hedging Activities

The company may apply hedge accounting to arrangements that qualify for designated hedge accounting treatment. Documentation is prepared at the inception of a hedge relationship in order to qualify for hedge accounting. Designated hedges are assessed at each reporting date to determine if the relationship between the derivative and the underlying hedged item accomplishes the company's risk management objectives for financial and non-financial risk exposures.

If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and in the fair value of the underlying hedged item are recognized in net earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in Other Comprehensive Income and are recognized in net earnings when the hedged item is realized. Ineffective portions of changes in the fair value of cash flow hedges are recognized in net earnings immediately. Changes in the fair value of a derivative designated in a fair value or cash flow hedge are recognized in the same line item as the underlying hedged item.

The company did not apply hedge accounting to any of its derivative instruments for the years ended December 31, 2022 or 2021.

(t) Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issuance of common shares are recognized as a deduction from equity, net of any tax effects. When the company repurchases its own common shares, share capital is reduced by the average carrying value of the shares repurchased. The excess of the purchase price over the average carrying value is recognized as a deduction from Retained Earnings. Shares are cancelled upon repurchase.

(u) Dividend Distributions

Dividends on common shares are recognized in the period in which the dividends are declared by the company's Board of Directors.

(v) Earnings per Share

Basic earnings per share is calculated by dividing the net earnings for the period by the weighted average number of common shares outstanding during the period.

Diluted earnings per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive common shares related to the company's share-based compensation plans. The number of shares included is computed using the treasury stock method. As these awards can be exchanged for common shares of the company, they are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share if they have a dilutive impact in the period.

(w) Emissions Obligations and Rights

Emissions obligations are measured at the weighted average cost per unit of emissions expected to be incurred to settle the obligation and are recorded in the period in which the emissions occur within Operating, Selling and General expense, or Purchases.

Purchases of emissions rights are recognized as Other Assets on the balance sheet and are measured at historical cost. Emissions rights received by way of grant are recorded at a nominal amount.

(x) Leases

At inception of a contract, the company assesses whether a contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

The company recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured based on the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset on the site on which it is located, less any lease incentives received. The assets are depreciated to the earlier of the end of the useful life of the right-of-use asset or the lease term. Judgment is applied to determine the lease term where a renewal option exists. Right-of-use assets are depreciated using the straight-line method as this most closely reflects the expected pattern of consumption of the future economic benefits. In addition, the right-of-use assets may be reduced by impairment losses or adjusted for certain remeasurements of the lease liability.

The company has elected not to recognize right-of-use assets and lease liabilities for short-term leases that have a lease term of twelve months or less. The lease payments are recognized as an expense when incurred over the lease term. As well, the company has accounted for each lease component and any non-lease components as a single lease component for crude oil storage tanks.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the company's incremental borrowing rate. Lease payments include fixed payments, and variable payments that are based on an index or rate.

Cash payments for the principal portion of the lease liability are presented within the financing activities section and the interest portion of the lease liability is presented within the operating activities section of the statement of cash flows. Short-term lease payments and variable lease payments not included in the measurement of the lease liability are presented within the operating activities section of the statement of cash flows.

The lease liability is measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the company's estimate of the amount expected to be payable under a residual value guarantee, or if the company changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The company has lease contracts which include storage tanks, pipelines, railway cars, vessels, buildings, land, and mobile equipment for the purpose of production, storage and transportation of crude oil and related products.

(y) Government Grants

Government grants are recognized when the company has reasonable assurance that it has complied with the relevant conditions of the grant and that it will be received. The company recognizes the grants that compensate the company for expenses incurred against the financial statement line item that it is intended to compensate, or to other income if the grant is recognized in a different period than the underlying transaction.

4. Significant Accounting Estimates and Judgments

The preparation of financial statements in accordance with IFRS requires management to make estimates and judgments that affect reported assets, liabilities, revenues, expenses, gains, losses and disclosures of contingencies. These estimates and judgments are subject to change based on experience and new information.

Climate Change and Energy Transition

Suncor supports the goals of the Paris Agreement and is committed to achieving the long-term target of net zero greenhouse gas (GHG) emissions by 2050 from its facilities, including those in which it has a working interest. Addressing climate change and providing the secure and reliable energy the world needs requires investment, technological advancement, product innovation, regulatory support and collaborative partnerships, such as the Pathway's Alliance. The rate of change of public policy, consumer behavior, and resulting demand for low carbon options is not certain. Suncor is committed to reducing emissions in our base business, while expanding in complementary low-emissions businesses and working with our customers, governments and partners to realize our shared climate objectives.

Climate change and the transition to a low-emissions economy was considered in preparing the consolidated financial statements, primarily in estimating commodity prices used in impairment and reserves analysis. These may have significant impacts on the currently reported amounts of the company's assets and liabilities discussed below and on similar assets and liabilities that may be recognized in the future. As part of its ongoing business planning, Suncor estimates future costs associated with GHG emissions in its operations and in the evaluation of future projects. The company uses future climate scenarios to test and assess the resilience of its strategy.

The financial statement areas that require significant estimates and judgments are as follows:

Oil and Gas Reserves

The company's estimate of oil and gas reserves is considered in the measurement of depletion, depreciation, impairment, and decommissioning and restoration obligations. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. All reserves have been evaluated at December 31, 2022, by independent qualified reserves evaluators. Oil and gas reserves estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Estimates reflect market and regulatory conditions existing at December 31, 2022, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions, as well as climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels can materially impact the estimation of net reserves. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

Oil and Gas Activities

The company is required to apply judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the costs of these activities shall be expensed or capitalized.

Exploration and Evaluation Costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The company is required to make judgments about future events and circumstances and applies estimates to assess the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop the project. Level of drilling success or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures are important judgments when making this determination. Management uses judgment to determine when these costs are reclassified to Property, Plant and Equipment based on several factors, including the existence of reserves, appropriate approvals from regulatory bodies, joint arrangement partners and the company's internal project approval process.

Determination of Cash Generating Units (CGUs)

A CGU is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructure and the way in which management monitors the operations.

Asset Impairment and Reversals

Management applies judgment in assessing the existence of impairment and impairment reversal indicators based on various internal and external factors.

The recoverable amount of CGUs and individual assets is determined based on the higher of fair value less costs of disposal or value-in-use calculations. The key estimates the company applies in determining the recoverable amount normally include estimated future commodity prices, discount rates, expected production volumes, future operating and development costs, income taxes and refining margins. In determining the recoverable amount, management may also be required to make judgments regarding the likelihood of occurrence of a future event. Changes to these estimates and judgments will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value. In addition, climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could result in a change in assumptions used in determining the recoverable amount and could affect the carrying value and useful life of the related assets. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of Exploration and Evaluation assets and Property, Plant and Equipment based on estimated future decommissioning and restoration costs. Management applies judgment in assessing the existence and extent as well as the expected method of reclamation of the company's decommissioning and restoration obligations at the end of each reporting period. Management also uses judgment to determine whether the nature of the activities performed is related to decommissioning and restoration activities or normal operating activities.

Actual costs are uncertain and estimates may vary as a result of changes to relevant laws and regulations related to the use of certain technologies, the emergence of new technology, operating experience, prices and closure plans. The estimated timing of future decommissioning and restoration may change due to certain factors, including reserves life. Changes to estimates related to future expected costs, discount rates, inflation assumptions and timing may have a material impact on the amounts presented. In addition, climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could result in a change in assumptions used in determining the carrying value of the liabilities. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

Employee Future Benefits

The company provides benefits to employees, including pensions and other post-retirement benefits. The cost of defined benefit pension plans and other post-retirement benefits received by employees is estimated based on actuarial valuation methods that require professional judgment. Estimates typically used in determining these amounts include, as applicable,

rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, the return on plan assets, mortality rates and future medical costs. Changes to these estimates may have a material impact on the amounts presented.

Other Provisions

The determination of other provisions, including, but not limited to, provisions for royalty disputes, onerous contracts, litigation and constructive obligations, is a complex process that involves judgment about the outcomes of future events, the interpretation of laws and regulations, and estimates on the timing and amount of expected future cash flows and discount rates.

Income Taxes

Management evaluates tax positions, annually or when circumstances require, which involves judgment and could be subject to differing interpretations of applicable tax legislation. The company recognizes a tax provision when a payment to tax authorities is considered probable. However, the results of audits and reassessments and changes in the interpretations of standards may result in changes to those positions and, potentially, a material increase or decrease in the company's assets, liabilities and net earnings.

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's judgment of the likelihood of a future outflow and estimates of the expected settlement amount, timing of reversals, and the tax laws in the jurisdictions in which the company operates.

5. New IFRS Standards

a) Adoption of New IFRS Standards

The standards, amendments and interpretations that are adopted up to the date of authorization of the company's consolidated financial statements, and that may have an impact on the disclosures and financial position of the company are disclosed below.

Property, Plant and Equipment: Proceeds before Intended Use

In May 2020, the IASB issued *Property, Plant and Equipment: Proceeds before Intended Use (Amendments to IAS 16)* . The amendments prohibit a company from deducting from the cost of property, plant and equipment revenues received from selling items produced while the company is preparing the asset for its intended use. Instead, a company will recognize such sales proceeds and related costs in profit or loss. The company adopted the amendments prospectively on the effective date January 1, 2022, and there was no impact to the consolidated financial statements as a result of the initial application.

Onerous Contracts – Cost of Fulfilling a Contract

In May 2020, the IASB issued *Onerous Contracts – Cost of Fulfilling a Contract (Amendments to IAS 37).* The amendments specify which costs an entity includes in determining the cost of fulfilling a contract for the purpose of assessing whether the contract is onerous. The company adopted the amendments prospectively on the effective date January 1, 2022, and there was no impact to the consolidated financial statements as a result of the initial application.

Fees in the "10 per cent" Test for Derecognition of Financial Liabilities

In May 2020, the IASB issued *Fees in the "10 per cent" Test for Derecognition of Financial Liabilities (Amendment to IFRS 9).* The amendment clarifies the fees a company includes when assessing whether the terms of a new or modified financial

liability are substantially different from the terms of the original financial liability. The company adopted the amendments prospectively on the effective date January 1, 2022, and there was no impact to the consolidated financial statements as a result of the initial application.

b) Recently Announced Accounting Pronouncements

The standards, amendments and interpretations that are issued, but not yet effective up to the date of authorization of the company's consolidated financial statements, and that may have an impact on the disclosures and financial position of the company are disclosed below. The company intends to adopt these standards, amendments and interpretations when they become effective.

Non-current Liabilities with Covenants

In October 2022, the IASB issued *Non-current Liabilities with Covenants (Amendments to IAS 1).* The amendments improved the information an entity provides when its right to defer settlement of a liability for at least twelve months is subject to compliance with covenants. The amendments are effective January 1, 2024, with early adoption permitted. The company does not anticipate any significant impact from these amendments on the consolidated financial statements as a result of the initial application.

Lease Liability in a Sale and Leaseback

In September 2022, the IASB issued *Lease Liability in a Sale and Leaseback (Amendments to IFRS 16).* The amendments add subsequent measurement requirements for sale and leaseback transactions. The amendments are effective January 1, 2024, with early adoption permitted. The company does not currently have any sale and leaseback transactions and therefore does not anticipate any changes resulting from these amendments on the consolidated financial statements as a result of the initial application.

6. Segmented Information

The company's operating segments are reported based on the nature of their products and services and management responsibility. The following summary describes the operations in each of the segments:

- Oil Sands includes the company's wholly owned operations in the Athabasca oil sands in Alberta to explore, develop and produce bitumen, synthetic crude oil and related products, through the recovery and upgrading of bitumen from mining and in situ operations. This segment also includes the company's joint interest in the Syncrude oil sands mining and upgrading operation, and the company's joint interest in the Fort Hills partnership as well as the marketing, supply, transportation and risk management of crude oil, natural gas, power and byproducts. The individual operating segments related to mining operations, In Situ, Fort Hills and Syncrude have been aggregated into one reportable segment (Oil Sands) due to the similar nature of their business activities, including the production of bitumen, and the single geographic area and regulatory environment in which they operate.

- Exploration and Production (E&P) includes offshore activity in East Coast Canada, with interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, the exploration and production of crude oil and natural gas at Buzzard (classified as assets held for sale and subsequent to the fourth quarter of 2022, the company reached an agreement for the sale of its United Kingdom (U.K.) operations - see note 33) and Golden Eagle Area Development in the U.K. (which was sold in 2021 – see note 16), exploration and production of crude oil and gas at Oda and the development of the Fenja field in Norway (the Norway assets were sold on September 30, 2022 – see note 16), as well as the marketing and risk management of crude oil and natural gas.

- Refining and Marketing includes the refining of crude oil products, and the distribution, marketing, transportation and risk management of refined and petrochemical products, and other purchased products through the retail and wholesale networks located in Canada and the United States (U.S.). The segment also includes trading of crude oil, natural gas and power.

The company also reports activities not directly attributable to an operating segment under Corporate and Eliminations. This includes renewable projects such as wind and solar power, as well as other investments in clean technology, such as

Suncor's investment in Enerkem Inc., LanzaJet, Inc., Svante Inc., the Varennes Carbon Recycling facility, the Pathways Alliance, and the early-stage design and engineering for the ATCO/Suncor hydrogen project. The wind and solar assets are classified as assets held for sale and subsequent to the fourth quarter of 2022, the company completed the sale of these assets (note 33).

Intersegment sales of crude oil and natural gas are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer. Intersegment balances are eliminated on consolidation. Intersegment profit is not recognized until the related product has been sold to third parties. Beginning in the first quarter of 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated net earnings and comparative periods have been revised to reflect this change.

For the years ended December 31 ($ millions)	Oil Sands		Exploration and Production		Refining and Marketing		Corporate and Eliminations		Total	
	2022	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Revenues and Other Income										
Gross revenues[1]	**21 905**	15 319	**4 331**	2 978	**36 622**	22 808	**49**	28	**62 907**	41 133
Intersegment revenues[1]	**8 526**	4 601	**-**	-	**106**	107	**(8 632)**	(4 708)	**-**	-
Less: Royalties	**(3 963)**	(1 523)	**(608)**	(478)	**-**	-	**-**	-	**(4 571)**	(2 001)
Operating revenues, net of royalties	**26 468**	18 397	**3 723**	2 500	**36 728**	22 915	**(8 583)**	(4 680)	**58 336**	39 132
Other (loss) income	**(53)**	6	**164**	17	**(60)**	(50)	**80**	(4)	**131**	(31)
	26 415	18 403	**3 887**	2 517	**36 668**	22 865	**(8 503)**	(4 684)	**58 467**	39 101
Expenses										
Purchases of crude oil and products[1]	**2 050**	1 444	**-**	-	**27 261**	16 807	**(8 536)**	(4 460)	**20 775**	13 791
Operating, selling and general	**9 152**	8 056	**490**	429	**2 427**	2 019	**738**	862	**12 807**	11 366
Transportation and distribution	**1 210**	1 126	**101**	112	**396**	282	**(36)**	(41)	**1 671**	1 479
Depreciation, depletion, amortization and impairment	**7 927**	4 585	**(105)**	324	**844**	853	**120**	88	**8 786**	5 850
Exploration	**37**	12	**19**	35	**-**	-	**-**	-	**56**	47
(Gain) loss on disposal of assets	**(7)**	(4)	**66**	(227)	**(11)**	(19)	**(3)**	(7)	**45**	(257)
Financing expenses	**413**	359	**95**	53	**57**	56	**1 446**	787	**2 011**	1 255
	20 782	15 578	**666**	726	**30 974**	19 998	**(6 271)**	(2 771)	**46 151**	33 531
Earnings (Loss) before Income Taxes	**5 633**	2 825	**3 221**	1 791	**5 694**	2 867	**(2 232)**	(1 913)	**12 316**	5 570
Income Tax Expense (Recovery)										
Current	**-**	-	**-**	-	**-**	-	**-**	-	**4 229**	**1 395**
Deferred	**-**	-	**-**	-	**-**	-	**-**	**-**	**(990)**	**56**
	-	-	**-**	-	**-**	-	**-**	-	**3 239**	1 451
Net Earnings	**-**	-	**-**	-	**-**	-	**-**	-	**9 077**	4 119
Capital and Exploration Expenditures[2]	**3 540**	3 168	**443**	270	**816**	825	**188**	292	**4 987**	4 555

(1) The company revised certain gross revenues and purchases of crude oil and products to align with current period presentation. For the twelve months ended December 31, 2022, gross revenues and purchases of crude oil and products decreased by $150 million, with no effect on net earnings.

(2) Excludes capital expenditures related to assets held for sale of $133 million for the year ended December 31, 2022.

Table of Contents

Disaggregation of Revenue from Contracts with Customers and Intersegment Revenue

The company's revenues are from the following major commodities and geographical regions:

For the years ended December 31 ($ millions)	2022 North America	2022 International	2022 Total	2021 North America	2021 International	2021 Total
Oil Sands						
Synthetic crude oil and diesel[1]	**22 539**	**-**	**22 539**	14 452	-	14 452
Bitumen	**7 892**	**-**	**7 892**	5 468	-	5 468
	30 431	**-**	**30 431**	19 920	-	19 920
Exploration and Production						
Crude oil and natural gas liquids	**2 464**	**1 834**	**4 298**	1 709	1 257	2 966
Natural gas	**-**	**33**	**33**	-	12	12
	2 464	**1 867**	**4 331**	1 709	1 269	2 978
Refining and Marketing						
Gasoline	**14 540**	**-**	**14 540**	9 983	-	9 983
Distillate	**18 663**	**-**	**18 663**	9 832	-	9 832
Other	**3 525**	**-**	**3 525**	3 100	-	3 100
	36 728	**-**	**36 728**	22 915	-	22 915
Corporate and Eliminations[1]						
	(8 583)	**-**	**(8 583)**	(4 680)	-	(4 680)
Total Gross Revenue from Contracts with Customers	**61 040**	**1 867**	**62 907**	39 864	1 269	41 133

(1) The company revised certain gross revenues and purchases of crude oil and products to align with current period presentation. For the twelve months ended December 31, 2022, gross revenues and purchases of crude oil and products decreased by $150 million, with no effect on net earnings.

Geographical Information

Operating Revenues, net of Royalties

($ millions)	2022	2021
Canada	**49 169**	32 286
United States	**7 544**	5 818
Other foreign	**1 623**	1 028
	58 336	39 132

Non-Current Assets[1]

($ millions)	December 31 2022	December 31 2021
Canada	**66 346**	68 900
United States	**2 629**	2 020
Other foreign	**1 026**	1 682
	70 001	72 602

(1) Excludes deferred income tax assets.

Table of Contents

7. Other Income

Other income consists of the following:

($ millions)	2022	2021
Energy trading and risk management	**(209)**	(165)
Investment and interest income	**100**	64
Insurance proceeds[1]	**179**	69
Other[2]	**61**	1
	131	(31)

(1) 2022 includes $147 million of property damage insurance proceeds related to the company's assets in Libya, within the Exploration and Production segment, and $32 million of insurance proceeds for the secondary extraction facilities at Oil Sands Base, within the Oil Sands segment. 2021 includes $31 million of insurance proceeds for the outages at Mackay River and $38 million for the secondary extraction facilities at Oil Sands Base, both within the Oil Sands segment.

(2) 2022 includes a US$50 million contingent consideration gain related to the sale of the company's 26.69% working interest in the Golden Eagle Area Development in the fourth quarter of 2021, within the Exploration and Production segment.

8. Operating, Selling and General Expense

Operating, Selling and General expense consists of the following:

($ millions)	2022	2021
Employee and contract service costs[1]	**8 037**	7 409
Materials and equipment[1]	**1 901**	1 931
Commodities[1]	**2 196**	1 523
Travel, marketing and other[1]	**673**	503
	12 807	11 366

(1) Prior period amounts have been reclassified to align with the current year presentation of Operating, Selling and General expense. For the year ended December 31, 2021, $564 million was reclassified from employee and contract service costs to materials and equipment and $23 million was reclassified from materials and equipment and travel, marketing and other to commodities. This reclassification had no effect on the operating, selling and general expense presentation on the consolidated statements of comprehensive income.

9. Financing Expenses

Financing expenses consist of the following:

($ millions)	2022	2021
Interest on debt	**815**	834
Interest on lease liabilities	**167**	161
Capitalized interest at 5.2% (2021 – 5.0%)	**(168)**	(144)
Interest expense	**814**	851
Interest on partnership liability	**51**	51
Interest on pension and other post-retirement benefits	**41**	59
Accretion	**316**	304
Foreign exchange loss (gain) on U.S. dollar denominated debt	**729**	(113)
Operational foreign exchange and other	**28**	23
Loss on extinguishment of long-term debt	**32**	80
	2 011	1 255

Table of Contents

10. Income Taxes

Income Tax Expense (Recovery)

($ millions)	2022	2021
Current:		
Current year	**4 333**	1 353
Adjustments in respect of current income tax of prior years	**(104)**	42
Deferred:		
Origination and reversal of temporary differences	**(1 063)**	29
Adjustments in respect of deferred income tax of prior years	**54**	23
Changes in tax rates and legislation	**(27)**	8
Movement in unrecognized deferred income tax assets	**46**	(4)
Total income tax expense	**3 239**	1 451

Reconciliation of Effective Tax Rate

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the difference is as follows:

($ millions)	2022	2021
Earnings before income tax	**12 316**	5 570
Canadian statutory tax rate	**24.16%**	24.24%
Statutory tax	**2 976**	1 350
Add (deduct) the tax effect of:		
Non-taxable component of capital losses (gains)	**67**	(12)
Share-based compensation and other permanent items	**-**	3
Assessments and adjustments	**(49)**	65
Impact of income tax rates and legislative changes (1)	**(84)**	8
Non-taxable component of dispositions	**(25)**	(66)
Foreign tax rate differential(2)	**290**	111
Movement in unrecognized deferred income tax assets	**46**	(4)
Other	**18**	(4)
Total income tax expense	**3 239**	1 451
Effective tax rate	**26.3%**	26.1%

(1) The twelve months ended December 31, 2022 includes a current income tax recovery of $39 million related to the sale of the company's wind and solar assets (note 33).

(2) The twelve months ended December 31, 2022 includes a deferred income tax recovery of $171 million related to the sale of the company's UK assets (note 33)

Deferred Income Tax Balances

The significant components of the company's deferred income tax (assets) liabilities and deferred income tax expense (recovery) are comprised of the following:

	Deferred Income Tax Expense (Recovery)		Deferred Income Tax Liability (Asset)	
($ millions)	**2022**	2021	**December 31 2022**	December 31 2021
Property, plant and equipment	**(729)**	(260)	**11 093**	11 477
Decommissioning and restoration provision	**(10)**	141	**(2 292)**	(1 936)
Employee retirement benefit plans	**(92)**	(142)	**(297)**	(470)
Tax loss carry-forwards	**(14)**	161	**(29)**	(15)
Other	**(145)**	156	**(111)**	25
Net deferred income tax (recovery) / expense and liability	**(990)**	56	**8 364**	9 081

Change in Deferred Income Tax Balances

($ millions)	**2022**	2021
Net deferred income tax liability, beginning of year	**9 081**	8 758
Recognized in deferred income tax (recovery) / expense	**(990)**	56
Recognized in other comprehensive income	**264**	277
Foreign exchange, acquisition and other	**9**	(10)
Net deferred income tax liability, end of year	**8 364**	9 081

Deferred Tax in Shareholders' Equity

($ millions)	**2022**	2021
Deferred Tax in Other Comprehensive Income		
Actuarial gain on employment retirement benefit plans	**264**	277
Total income tax expense reported in equity	**264**	277

Deferred income tax assets are recognized for tax loss carry-forwards to the extent that the realization of the related tax benefit is probable based on estimated future earnings. Suncor has not recognized a $120 million (2021 – $74 million) deferred income tax asset on $986 million (2021 – $606 million) of capital losses related to unrealized foreign exchange on U.S. dollar denominated debt, which can only be utilized against future capital gains.

No deferred tax liability has been recognized at December 31, 2022, on unremitted net earnings of foreign subsidiaries, as the company is able to control the timing and amount of distributions and is not expected to incur any taxes associated with future distributions.

11. Earnings per Common Share

($ millions)	2022	2021
Net earnings	**9 077**	4 119
(millions of common shares)		
Weighted average number of common shares	**1 387**	1 488
Dilutive securities:		
Effect of share options	**3**	1
Weighted average number of diluted common shares	**1 390**	1 489
(dollars per common share)		
Basic earnings per share	**6.54**	2.77
Diluted earnings per share	**6.53**	2.77

12. Cash and Cash Equivalents

($ millions)	December 31 2022	December 31 2021
Cash	**1 782**	1 971
Cash equivalents	**198**	234
	1 980	2 205

13. Supplemental Cash Flow Information

The (increase) decrease in non-cash working capital is comprised of:

($ millions)	2022	2021
Accounts receivable	**(1 750)**	(1 324)
Inventories	**(1 128)**	(551)
Accounts payable and accrued liabilities	**1 512**	1 588
Current portion of provisions	**(286)**	235
Income taxes payable (net)[(1)]	**(717)**	1 830
	(2 369)	1 778
Relating to:		
Operating activities	**(2 421)**	1 507
Investing activities	**52**	271
	(2 369)	1 778

(1) During the twelve months ended December 31, 2022, the decrease in taxes payable was primarily related to the company's tax installment payments, net of the current income tax expense. During the twelve months ended December 31, 2021, the increase in taxes payable was primarily related to the company's 2021 current income tax expense, which was paid in the first quarter of 2022.

Reconciliation of movements of liabilities to cash flows arising from financing activities:

($ millions)	Short-Term Debt	Current Portion of Long-Term Lease Liabilities	Long-Term Lease Liabilities	Current Portion of Long-Term Debt	Long-Term Debt	Partnership Liability	Dividends Payable
At December 31, 2020	3 566	272	2 636	1 413	13 812	436	-
Changes from financing cash flows:							
Reduction of commercial paper	(2 256)	-	-	-	-	-	-
Gross proceeds from issuance of long-term debt	-	-	-	-	1 446	-	-
Debt issuance costs	-	-	-	-	(23)	-	-
Repayment of long-term debt	-	-	-	(2 451)	-	-	-
Loss on extinguishment of long-term debt	-	-	-	80	-	-	-
Realized foreign exchange (gains) and losses	(79)	-	-	128	-	-	-

Dividends paid on common shares	-	-	-	-	-	-	1 550
Lease liability payments	-	(325)	-	-	-	-	-
Distributions to non-controlling interest	-	-	-	-	-	(9)	-
Other	-	-	-	25	-	-	-
Non-cash changes:							
Dividends declared on common shares	-	-	-	-	-	-	(1 550)
Unrealized foreign exchange losses and (gains)	53	-	-	(47)	(168)	-	-
Reclassification of debt	-	-	-	1 083	(1 083)	-	-
Lease derecognition	-	-	(41)	-	-	-	-
Reclassification of lease obligations	-	363	(363)	-	-	-	-
Deferred financing costs	-	-	-	-	5	-	-
New lease liabilities	-	-	308	-	-	-	-
At December 31, 2021	1 284	310	2 540	231	13 989	427	-
Changes from financing cash flows:							
Net issuance of commercial paper	**1 473**	**-**	**-**	**-**	**-**	**-**	**-**
Repayment of long-term debt	**-**	**-**	**-**	**(233)**	**(4 895)**	**-**	**-**
Loss on extinguishment of long-term debt	**-**	**-**	**-**		**32**	**-**	**-**
Realized foreign exchange (gains) and losses	**(19)**	**15**	**-**	**2**	**(91)**	**-**	**-**
Dividends paid on common shares	**-**	**-**	**-**	**-**	**-**	**-**	**(2 596)**
Lease liability payments	**-**	**(329)**	**-**	**-**	**-**	**-**	**-**
Distributions to non-controlling interest	**-**	**-**	**-**	**-**	**-**	**(14)**	**-**
Other	**-**	**-**	**-**	**-**	**(13)**	**-**	**-**
Non-cash changes:							
Dividends declared on common shares	**-**	**-**	**-**	**-**	**-**	**-**	**2 596**
Unrealized foreign exchange losses and (gains)	**69**	**-**	**(25)**	**-**	**778**	**-**	**-**
Lease derecognition	**-**	**-**	**(22)**	**-**	**-**	**-**	**-**
Reclassification of lease obligations	**-**	**321**	**(321)**	**-**	**-**	**-**	**-**
Deferred financing costs	**-**	**-**	**-**	**-**	**-**	**-**	**-**
New lease liabilities	**-**	**-**	**523**	**-**	**-**	**-**	**-**
At December 31, 2022	**2 807**	**317**	**2 695**	**-**	**9 800**	**413**	**-**

14. Inventories

($ millions)	December 31 2022	December 31 2021
Crude oil[1]	**2 373**	1 501
Refined products	**2 014**	1 820
Materials, supplies and merchandise	**685**	789
Reclassified to assets held for sale (note 33)	**(14)**	-
	5 058	4 110

(1) Includes $131 million of inventories held for trading purposes (2021 – $110 million), which are measured at fair value less costs to sell based on Level 1 and Level 2 fair value inputs.

During 2022, purchased product inventories of $21.7 billion (2021 – $14.7 billion) were recorded as an expense.

15. Property, Plant and Equipment

($ millions)	Oil and Gas Properties	Plant and Equipment	Total

Cost			
At December 31, 2020[1]	43 622	84 036	127 658
Additions	755	3 901	4 656
Transfers from exploration and evaluation	-	-	-
Changes in decommissioning and restoration	(1 127)	(5)	(1 132)
Disposals and derecognition	(1 902)	(2 652)	(4 554)
Foreign exchange adjustments	(118)	49	(69)
At December 31, 2021[1]	41 230	85 329	126 559
Additions	**1 149**	**4 261**	**5 410**
Transfers from exploration and evaluation	**34**	**-**	**34**
Changes in decommissioning and restoration	**1 321**	**(10)**	**1 311**
Disposals and derecognition	**(585)**	**(884)**	**(1 469)**
Foreign exchange adjustments	**101**	**218**	**319**
Reclassified to assets held for sale (note 33)	**(4 475)**	**(480)**	**(4 955)**
At December 31, 2022	**38 775**	**88 434**	**127 209**
Accumulated provision			
At December 31, 2020[1]	(25 757)	(33 771)	(59 528)
Depreciation, depletion, amortization and impairment	(1 216)	(4 465)	(5 681)
Disposals and derecognition	1 676	2 452	4 128
Foreign exchange adjustments	70	(2)	68
At December 31, 2021[1]	(25 227)	(35 786)	(61 013)
Depreciation, depletion, amortization and impairment	**(1 049)**	**(7 347)**	**(8 396)**
Disposals and derecognition	**510**	**338**	**848**
Foreign exchange adjustments	**(60)**	**(107)**	**(167)**
Reclassified to assets held for sale (note 33)	**4 111**	**62**	**4 173**
At December 31, 2022	**(21 715)**	**(42 840)**	**(64 555)**
Net property, plant and equipment			
December 31, 2021[1]	16 003	49 543	65 546
December 31, 2022	**17 060**	**45 594**	**62 654**

(1) For the years ended December 31, 2020 and December 31, 2021, the company reclassified certain balances between oil and gas properties and plant and equipment. This reclassification had no effect on net property, plant and equipment.

	December 31, 2022			December 31, 2021		
($ millions)	**Cost**	**Accumulated Provision**	**Net Book Value**	Cost	Accumulated Provision	Net Book Value
Oil Sands	**92 601**	**(45 288)**	**47 313**	87 849	(37 971)	49 878
Exploration and Production	**16 541**	**(11 360)**	**5 181**	21 495	(15 999)	5 496
Refining and Marketing	**17 101**	**(7 435)**	**9 666**	15 989	(6 596)	9 393
Corporate and Eliminations	**966**	**(472)**	**494**	1 226	(447)	779
	127 209	**(64 555)**	**62 654**	126 559	(61 013)	65 546

At December 31, 2022, the balance of assets under construction and not subject to depreciation or depletion was $ 6.3 billion (December 31, 2021 – $4.6 billion).

16. Asset Impairments and Transactions

No indicators of impairment or reversals of impairment were identified at December 31, 2022.

Oil Sands

Fort Hills assets:

During the fourth quarter of 2022, the company entered into an agreement to acquire Teck Resources Limited's (Teck) 21.3% interest in the Fort Hills Project (Fort Hills) and its associated sales and logistics agreements for $1.0 billion, subject to working capital and other closing adjustments. Subsequent to the fourth quarter of 2022, TotalEnergies EP Canada Ltd. provided notice of the exercise of its contractual right of first refusal to acquire from Teck a 6.65% interest in Fort Hills, which reduced the amount of working interest available for Suncor to purchase. As a result, on February 2, 2023, Suncor completed the acquisition of an additional 14.65% working interest in Fort Hills for $688 million, before working capital and other closing adjustments, bringing the company's and its affiliate's total aggregate working interest in Fort Hills to 68.76%. Due to the limited time between the acquisition and the preparation of these consolidated financial statements, the timing of closing adjustments, the value of the assets acquired and the liabilities assumed on the acquisition were not finalized to complete the purchase price allocation.

Prior to entering the agreement with Teck, the company also updated its long-range plan for Fort Hills, which incorporated lower gross production and increased operating costs per barrel for the next three years. Management considered these indicators of impairment and performed an asset impairment test using recoverable amounts based on fair value less costs of disposal. An impairment charge of $2.6 billion (net of taxes of $0.8 billion) was recognized on its share of Fort Hills in the Oil Sands segment in the third quarter of 2022. An expected cash flow approach with the following asset specific assumptions (Level 3 fair value inputs note 27) were applied:

- Western Canada Select (WCS) price forecast of US$69.00/bbl in 2023, US$62.00/bbl in 2024, and an average price of US$50.00/bbl between 2025 and 2031, escalating at 2% per year thereafter over the life of the project up to 2060, adjusted for asset-specific location and quality differentials;
- the company's share of production ranging from 87,000 to 106,000 bbls/d over the life of the project;
- cash operating costs averaging approximately $25.00/bbl over the life of the project (expressed in real dollars), which reflects operating, selling and general expenses adjusted for non-production costs, including share-based compensation, research costs, and excess power revenue;
- foreign exchange rate of US$0.76 per one Canadian dollar; and
- risk adjusted discount rate of 8.25% (after-tax).

The recoverable amount of the Fort Hills cash generating unit (CGU) was $2.8 billion (net of taxes) as at September 30, 2022. The recoverable amount estimate is most sensitive to price and discount rate. A 5% average decrease in price over the life of the project would have resulted in an additional impairment charge of approximately $1.0 billion (after-tax) on the company's share of the Fort Hills assets. A 1% increase in the discount rate would have resulted in an additional impairment charge of approximately $0.2 billion (after-tax) on the company's share of the Fort Hills assets.

Exploration and Production

White Rose assets:

In the second quarter of 2022, the company announced that concurrent with the decision to restart the West White Rose project by the joint venture owners, Suncor increased its ownership in the White Rose asset by 12.5% to approximately 39% (previously approximately 26%). The decision to restart was driven by a revised royalty structure and development plan. The company received $38 million (net of taxes of $12 million) in cash consideration to acquire the additional working interest, which was primarily allocated to the asset retirement obligation and property, plant and equipment of the project. As a result of these events, during the second quarter of 2022, the company performed an impairment reversal test on the White Rose CGU as the recoverable amount of this CGU was sensitive to the restart decision. The impairment reversal test was performed using a recoverable amount based on the fair value less cost of disposal. An expected cash flow approach was used with the key assumptions discussed below (Level 3 fair value inputs note 27).

As a result of the impairment reversal test, the recoverable amounts were determined to be greater than the carrying values of the White Rose CGU and the company recorded an impairment reversal of $542 million (net of taxes of $173 million) on its previous share of the White Rose assets in the Exploration and Production segment. The recoverable amount was determined based on the following asset-specific assumptions:

- Brent price forecast of US$85.00/bbl in 2023, US$68.00 in 2024 and US$69.00 in 2025, escalating at 2% per year thereafter over the life of the project to 2038 and adjusted for asset-specific location and quality differentials;
- anticipated first oil for the West White Rose project in the first half of 2026 and the company's share of production of approximately 9,800 bbls/d (based on its previous working interest of approximately 26%) over the life of the project;
- the company's share of future capital expenditures of $1.5 billion, including the West White Rose expansion; and
- risk-adjusted discount rate of 9.0% (after-tax).

Norway assets:

During the third quarter of 2022, the company completed the sale of its Norway assets, including its 30% working interest in Oda and its 17.5% working interest in the Fenja Development Joint Operations, for net proceeds of $297 million (net of cash disposed of $133 million), resulting in a $65 million loss including foreign exchange impacts. The company completed the sale on September 30, 2022. The Norway assets are reported in the Exploration and Production segment.

In the second quarter of 2022, the company reclassified the assets and liabilities related to its Norway operations as assets held for sale and performed an impairment test on the Norway assets held for sale as at June 30, 2022. The impairment test was performed using the lower of its carrying amount and fair value less costs to sell (Level 2 fair value inputs note 27). As a result of the impairment test, the company recorded a $47 million charge related to the impairment on its share of the Norway operations, net of a $23 million deferred tax adjustment associated with the assets held for sale.

Asset Impairments and Transactions in 2021

Oil Sands

Fort Hills assets:

During the fourth quarter of 2021, the company performed an asset impairment test on its Fort Hills CGU due to changes in its mine plan. The impairment test was performed using recoverable amounts based on fair value less cost of disposal. An expected cash flow approach was used with the following asset-specific assumptions (Level 3 fair value inputs note 27):

- WCS price forecast of US$55.00/bbl in 2022, US$54.57/bbl in 2023, and an average price of US$50.86/bbl between 2024 and 2031, escalating at 2% per year thereafter over the life of the project up to 2058, adjusted for asset-specific location and quality differentials;
- the company's share of production ranging from 94,000 to 111,000 bbls/d over the life of the project;
- cash operating costs averaging $22.00/bbl to $23.00/bbl over the life of the project (expressed in real dollars), which reflects operating, selling and general expenses adjusted for non-production costs, including share-based compensation, research costs, and excess power revenue;
- foreign exchange rate of US$0.80 per one Canadian dollar; and
- risk-adjusted discount rate of 7.5% (after-tax).

Factors including an improved WCS price forecast in the next two years and optimization of the mine plan to exclude certain high strip ratio zones were offset by higher operating and capital costs. The recoverable amount of the Fort Hills CGU was $5.5 billion as at December 31, 2021, which indicated that no impairment loss or reversal was required.

The recoverable amount estimate is most sensitive to price and discount rate. A 5% average decrease in price over the life of the project would have resulted in an impairment charge of approximately $1.0 billion (after-tax) on the company's share of the Fort Hills assets. A 1% increase in the discount rate would have resulted in an impairment charge of approximately $ 0.5 billion (after-tax) on the company's share of the Fort Hills assets.

Exploration and Production

Terra Nova assets:

During the third quarter of 2021, the company finalized an agreement with the co-owners of the Terra Nova Project to restructure the project ownership and move forward with the Asset Life Extension Project. The agreement increased the company's working interest to 48% (previously approximately 38%) and includes royalty and financial support from the Government of Newfoundland and Labrador. The company received $26 million (net of taxes of $8 million) in cash consideration to acquire the additional 10% working interest, which was primarily allocated to the asset retirement obligation and property, plant and equipment of the project. As a result of these events, during the third quarter of 2021, the company performed an impairment reversal test on the Terra Nova CGU as the recoverable amount of this CGU was sensitive to the financial support from the Government of Newfoundland and Labrador and revised royalty structure resulting in increased profitability and economic value. The impairment reversal test was performed using recoverable amounts based on the fair value less cost of disposal. An expected cash flow approach was used with the key assumptions discussed below (Level 3 fair value inputs note 27).

As a result of the impairment reversal test, the recoverable amounts were determined to be greater than the carrying values of the Terra Nova CGU and the company recorded an impairment reversal of $168 million (net of taxes of $53 million) on its share of the Terra Nova assets in the Exploration and Production segment in the third quarter of 2021. In addition to the financial support from the government, the recoverable amount was determined based on the following asset-specific assumptions:

- Brent price forecast of US$65.00/bbl in 2023 and US$68.00/bbl in 2024, escalating at 2% per year thereafter over the life of the project to 2033 and adjusted for asset-specific location and quality differentials;
- the anticipated return to operations before the end of 2022 and the company's share of production of approximately 6,000 bbls/d (based on its previous 38% working interest) over the life of the project; and
- risk-adjusted discount rate of 9.0% (after-tax).

The recoverable amount of the Terra Nova CGU was $177 million as at September 30, 2021.

No indicators of impairment or reversals of impairment were identified as at December 31, 2021.

United Kingdom assets:

During the fourth quarter of 2021, the company completed the sale of its 26.69% working interest in the Golden Eagle Area Development, reported within the Exploration and Production segment, for gross proceeds of US$250 million net of closing adjustments and other closing costs, resulting in a gain on sale of $227 million ($227 million after-tax). The company recognized US$50 million of contingent consideration in 2022 related to the asset disposal.

17. Right-of-Use Assets and Leases

Right-of-use (ROU) assets within Property, Plant and Equipment:

($ millions)	**December 31 2022**	December 31 2021
Property, plant and equipment, net – excluding ROU assets	**59 778**	62 821
ROU assets	**2 876**	2 725
	62 654	65 546

The following table presents the ROU assets by asset class:

($ millions)	Plant and Equipment
Cost	

At January 1, 2021	3 786
Additions and adjustments	307
Disposals	(232)
Foreign exchange	-
At December 31, 2021	3 861
Additions and adjustments	**523**
Disposals	**(156)**
Foreign exchange	**20**
At December 31, 2022	**4 248**

Accumulated provision

At January 1, 2021	(962)
Depreciation	(396)
Disposals	221
Foreign exchange	1
At December 31, 2021	(1 136)
Depreciation	**(356)**
Disposals	**126**
Foreign exchange	**(6)**
At December 31, 2022	**(1 372)**

Net ROU assets

At December 31, 2021	2 725
At December 31, 2022	**2 876**

Other lease-related items recognized in the Consolidated Statements of Comprehensive Income (Loss):

There were no leases with residual value guarantees. For the year ended December 31, 2022, total cash outflow for leases, excluding short-term lease expense and variable lease expense, was $496 million (2021 – $486 million).

18. Exploration and Evaluation Assets

($ millions)	December 31 2022	December 31 2021
Beginning of year	**2 226**	2 286
Acquisitions and additions	**41**	2
Transfers to oil and gas assets	**(34)**	-
Disposals and derecognition	**-**	(54)
Reclassified to assets held for sale (note 33)	**(239)**	-
Foreign exchange adjustments	**1**	(8)
End of year	**1 995**	2 226

19. Other Assets

($ millions)	December 31 2022	December 31 2021
Investments	**758**	391
Prepaids and other	**796**	916
Pension (note 23)	**212**	-
	1 766	1 307

Investments includes the company's investments in clean technology, such as Suncor's investment in Enerkem Inc., LanzaJet, Inc., Svante Inc. and the Varennes Carbon Recycling facility, in addition to the company's investments in various pipelines.

Prepaids and other includes long-term accounts receivable related to deposits paid on account to support reclamation activities into the Syncrude Reclamation Trust, Notices of Reassessments that have been received from the Canada Revenue Agency, and emissions credits and are unlikely to be settled within one year.

20. Goodwill and Other Intangible Assets

($ millions)	Oil Sands Goodwill	Refining and Marketing Goodwill	Other Intangibles	Total
At December 31, 2020	2 752	140	436	3 328
Additions	-	-	213	213
Amortization	-	-	(18)	(18)
At December 31, 2021	2 752	140	631	3 523
Additions	**-**	**-**	**140**	**140**
Amortization	**-**	**-**	**(57)**	**(57)**
Reclassified to assets held for sale (note 33)	**-**	**-**	**(20)**	**(20)**
At December 31, 2022	**2 752**	**140**	**694**	**3 586**

The company performed a goodwill impairment test at December 31, 2022 on its Oil Sands segment. Recoverable amounts were based on fair value less costs of disposal calculated using the present value of the segment's expected future cash flows.

Cash flow forecasts are based on past experience, historical trends, third-party evaluations of the company's reserves and resources to estimate production profiles and volumes, and estimates of operating costs, maintenance and capital expenditures. These estimates are validated against the estimates approved through the company's annual reserves evaluation process and determine the duration of the underlying cash flows used in the discounted cash flow test. Projected cash flows reflect current market assessments of key assumptions, including climate change, long-term forecasts of commodity prices, inflation rates, foreign exchange rates and discount rates (Level 3 fair value inputs note 27).

Future cash flow estimates are discounted using after-tax risk-adjusted discount rates. The after-tax discount rate applied to cash flow projections was an average of 7.8% (2021 – 7.5%). The company based its cash flow projections on a West Texas Intermediate price of US$80.00/bbl in 2023, US$71.40/bbl in 2024, US$62.42/bbl in 2025 and escalating at an average of 2% thereafter, adjusted for applicable quality and location differentials. The forecast cash flow period ranged from 50 years to 55 years. As a result of this analysis, management did not identify any impairment of goodwill within the Oil Sands operating segment.

The company also performed a goodwill impairment test of its Refining and Marketing CGUs. The recoverable amounts are based on fair value less costs of disposal calculated using the present value of the CGUs' expected future cash flows, based primarily on historical results adjusted for current economic conditions. As a result of this analysis, management did not identify any impairment of goodwill within the Refining and Marketing segment.

21. Debt and Credit Facilities

Debt and credit facilities are comprised of the following:

Short-Term Debt

($ millions)	**December 31 2022**	December 31 2021
Commercial paper[1]	2 807	1 284

(1) The commercial paper is supported by a revolving credit facility with a syndicate of lenders. The company is authorized to issue commercial paper to a maximum of $5.0 billion having a term not to exceed 365 days. The weighted average interest rate as at December 31, 2022 was 4.93% (December 31, 2021 - 0.33%).

Long-Term Debt

($ millions)	December 31 2022	December 31 2021
Fixed-term debt[2][3]		
4.50% Notes, due 2022 (US$182)[4]	**-**	231
2.80% Notes, due 2023 (US$450)	**-**	569
3.10% Notes, due 2025 (US$550)	**-**	696
3.00% Series 5 Medium Term Notes, due 2026	**115**	699
7.875% Debentures, due 2026 (US$275)	**381**	359
8.20% Notes, due 2027 (US$59)[4]	**61**	78
7.00% Debentures, due 2028 (US$250)	**342**	320
3.10% Series 6 Medium Term Notes, due 2029	**79**	748
5.00% Series 7 Medium Term Notes, due 2030	**154**	1 247
7.15% Notes, due 2032 (US$500)	**676**	631
5.35% Notes, due 2033 (US$300)	**161**	355
5.95% Notes, due 2034 (US$500)	**675**	630
5.95% Notes, due 2035 (US$600)	**268**	731
5.39% Series 4 Medium Term Notes, due 2037	**279**	599
6.50% Notes, due 2038 (US$1 150)	**1 553**	1 451
6.80% Notes, due 2038 (US$900)	**1 235**	1 156
6.85% Notes, due 2039 (US$750)	**1 013**	946
6.00% Notes, due 2042 (US$152)[4]	**35**	149
4.34% Series 5 Medium Term Notes, due 2046	**300**	300
4.00% Notes, due 2047 (US$750)	**1 011**	945
3.95% Series 8 Medium Term Notes, due 2051	**493**	493
3.75% Notes, due 2051 (US$750)	**1 009**	945
Total unsecured long-term debt	**9 840**	14 278
Lease liabilities[5]	**3 012**	2 850
Deferred financing costs	**(40)**	(58)
	12 812	17 070
Current portion of long-term debt and lease liabilities		
Lease liabilities	**(317)**	(310)
Long-term debt	**-**	(231)
	(317)	(541)
Total long-term lease liabilities	**2 695**	2 540
Total long-term debt	**9 800**	13 989

(2) The value of debt includes the unamortized balance of premiums or discounts.

(3) Certain securities are redeemable at the option of the company.

(4) Debt acquired through the acquisition of Canadian Oil Sands Limited (COS).

(5) Interest rates range from 0.4% to 13.4% and maturity dates range from 2023 to 2062.

In the fourth quarter of 2022, the company executed a debt tender offer pursuant to which it repaid $3.6 billion aggregate principal amount of debt at an amount below par of $51 million plus accrued and unpaid interest. As a result of the extinguishment, the company incurred non-cash charges of $83 million related to accelerated amortization. This resulted in a total loss on extinguishment of long-term debt of $32 million. The general terms of the notes that were extinguished are as follows:

- 3.00% Series 5 Medium Term Notes, due 2026, with a principal amount of $700 million (partial repayment of $585 million);
- 8.20% Notes, due 2027, with a principal amount of US $59 million (partial repayment of US $16 million);

- 3.10% Series 6 Medium Term Notes, due 2029, with a principal amount of $750 million (partial repayment of $671 million);
- 5.00% Series 7 Medium Term Notes, due 2030, with a principal amount of $1.3 billion (partial repayment of $1.1 billion);
- 5.35% Notes, due 2033, with a principal amount of US $300 million (partial repayment of US $178 million);
- 5.95% Notes, due 2035, with a principal amount of US $600 million (partial repayment of US $401 million);
- 5.39% Series 4 Medium Term Notes, due 2037, with a principal amount of $600 million (partial repayment of $321 million); and
- 6.00% Notes, due 2042, with a principal amount of US $142 million (partial repayment of US $110 million).

In the second quarter of 2022, the company completed an early redemption, at par, of its outstanding US$ 450 million 2.80% notes and US $550 million 3.10% notes, originally due in 2023 and 2025, respectively. The company also completed a partial redemption, at par, for US$10.2 million of its outstanding US$ 152 million 6.00% notes, due in 2042.

In the first quarter of 2022, the company completed an early redemption of its outstanding US $182 million 4.50% notes, originally scheduled to mature in the second quarter of 2022.

During the fourth quarter of 2021, the company repaid its US$ 300 million (book value of $ 371 million) senior unsecured notes at maturity with a coupon of 9.25%, for US$314 million ($388 million), including US$14 million ($17 million) of accrued interest.

In the third quarter of 2021, the company completed an early redemption of its US$ 750 million (book value of $ 951 million) senior unsecured notes with a coupon interest of 3.60% originally scheduled to mature on December 1, 2024, for US$ 822 million ($ 1.0 billion), including US$9 million ($ 11 million) of accrued interest, resulting in a debt extinguishment loss of $ 80 million ($60 million after tax).

On March 4, 2021, the company issued US$ 750 million of senior unsecured notes maturing on March 4, 2051. The notes have a coupon of 3.75% and were priced at US$ 99.518 per US$100 principal amount for an effective yield of 3.777%. The company also issued $500 million of senior unsecured Series 8 medium-term notes on March 4, 2021, maturing on March 4, 2051. The notes have a coupon of 3.95% and were priced at $ 98.546 per $100 principal amount for an effective yield of 4.034%. Interest on the 3.75% and 3.95% notes is paid semi-annually.

In the first quarter of 2021, the company completed an early redemption of its $ 750 million senior unsecured Series 5 medium-term notes with a coupon of 3.10%, originally scheduled to mature on November 26, 2021, for $ 770 million, including $8 million of accrued interest, resulting in a debt extinguishment loss of $12 million ($9 million after-tax). The company also completed an early redemption of its US$220 million (book value of $ 278 million) senior unsecured notes with a coupon of 9.40%, originally scheduled to mature on September 1, 2021, for US$230 million ($290 million), including US$2 million ($2 million) of accrued interest, resulting in a debt extinguishment loss of $10 million ($8 million after-tax).

Scheduled Debt Repayments

Scheduled principal repayments as at December 31, 2022 for lease liabilities, short-term debt and long-term debt are as follows:

($ millions)	Repayment
2023	3 124
2024	264
2025	241
2026	691
2027	244
Thereafter	11 101
	15 665

Credit Facilities

A summary of available and unutilized credit facilities is as follows:

($ millions)	2022
Fully revolving and expires in 2026	**3 000**
Fully revolving and expires in 2025	**2 707**
Can be terminated at any time at the option of the lenders	**1 520**
Total credit facilities	**7 227**
Credit facilities supporting outstanding commercial paper	**(2 807)**
Credit facilities supporting standby letters of credit	**(1 148)**
Total unutilized credit facilities (1)	**3 272**

(1) Available credit facilities for liquidity purposes at December 31, 2022 decreased to $2.900 billion, compared to $4.247 billion at December 31, 2021.

22. Other Long-Term Liabilities

($ millions)	December 31 2022	December 31 2021
Pensions and other post-retirement benefits (note 23)	**564**	1 207
Share-based compensation plans (note 26)	**469**	291
Partnership liability (note 27) (1)	**413**	427
Deferred revenue	**22**	29
Libya Exploration and Production Sharing Agreement (EPSA) signature bonus (2)	**80**	74
Other	**94**	152
	1 642	2 180

(1) The company paid $60 million in 2022 (2021 – $60 million) in distributions to the partners of the East Tank Farm Development, of which $51 million (2021 – $51 million) was allocated to interest expense and $9 million (2021 – $9 million) to the principal.

(2) The company has a US $500 million obligation for a signature bonus relating to Petro-Canada's ratification of six EPSAs in Libya. At December 31, 2022, the carrying amount of the Libya EPSAs' signature bonus so was $85 million (December 31, 2021 – $78 million). The current portion is $5 million (December 31, 2021 – $4 million) and is recorded in Accounts Payable and Accrued Liabilities.

23. Pensions and Other Post-Retirement Benefits

The company's defined benefit pension plans provide pension benefits at retirement based on years of service and final average earnings (if applicable). These obligations are met through funded registered retirement plans and through unregistered supplementary pensions that are funded through retirement compensation arrangements, and/or paid directly to recipients. The company's contributions to the funded plans are deposited with independent trustees who act as custodians of the plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Asset-liability matching studies are performed by a third-party consultant to set the asset mix by quantifying the risk-and-return characteristics of possible asset mix strategies. Investment and contribution policies are integrated within this study, and areas of focus include asset mix as well as interest rate sensitivity.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada and the U.K., and every year in the United States and Germany. The most recent valuations for the registered Canadian plans and U.K. plans were performed as at December 31, 2022. The company uses a measurement date of December 31 to value the plan assets and remeasure the accrued benefit obligation for accounting purposes.

The company's other post-retirement benefits programs are unfunded and include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

The company reports its share of Syncrude's defined benefit and defined contribution pension plans and Syncrude's other post-retirement benefits plan.

The company also provides a number of defined contribution plans, including a U.S. 401(k) savings plan, that provide for an annual contribution of 5% to 11.5% of each participating employee's pensionable earnings.

Defined Benefit Obligations and Funded Status

($ millions)	Pension Benefits 2022	Pension Benefits 2021	Other Post-Retirement Benefits 2022	Other Post-Retirement Benefits 2021
Change in benefit obligation				
Benefit obligation at beginning of year	**8 303**	8 682	**672**	690
Current service costs	**263**	302	**19**	19
Plan participants' contributions	**17**	17	**-**	-
Benefits paid	**(367)**	(350)	**(28)**	(27)
Interest costs	**246**	222	**20**	18
Foreign exchange	**(2)**	(6)	**-**	-
Settlements	**10**	11	**-**	-
Actuarial remeasurement:				
Experience (gain) loss arising on plan liabilities	**(86)**	(1)	**3**	(1)
Actuarial gain arising from changes in demographic assumptions	**-**	(2)	**-**	-
Actuarial gain arising from changes in financial assumptions	**(2 229)**	(572)	**(167)**	(27)
Benefit obligation at end of year	**6 155**	8 303	**519**	672
Change in plan assets				
Fair value of plan assets at beginning of year	**7 701**	7 305	**-**	-
Employer contributions	**61**	(11)	**-**	-
Plan participants' contributions	**17**	17	**-**	-
Benefits paid	**(347)**	(325)	**-**	-
Foreign exchange	**(4)**	(5)	**-**	-
Settlements	**10**	11	**-**	-
Administrative costs	**(2)**	(2)	**-**	-
Income on plan assets	**225**	181	**-**	-
Actuarial remeasurement:				
Return on plan assets greater / (less) than discount rate	**(1 190)**	530	**-**	-
Fair value of plan assets at end of year	**6 471**	7 701	**-**	-
Effect of the asset ceiling	**187**	-	**-**	-
Net surplus / (unfunded obligation) at end of year	**129**	**(602)**	**(519)**	**(672)**

The defined benefit asset (liability) is included as follows in the Consolidated Balance Sheet:

($ millions)	December 31 2022	December 31 2021
Amounts charged to		
Other assets (note 19)	**212**	-
Accounts payable and accrued liabilities	**(38)**	(67)
Other long-term liabilities (note 22)	**(564)**	(1 207)
	(390)	(1 274)

In June 2020, the Government of Alberta issued an amendment to the Employment Pension Plans Regulation to provide additional forms of relief to administrators of Alberta-registered pension plans. The company was approved for funding relief starting in late 2020 for both the defined benefit plan and the defined contribution plan based on funding levels in the defined benefit plan. In 2021, employer contributions reflect the contribution holiday and a transfer of funds from the defined benefit plan to the defined contribution plan, with the company resuming cash contributions near the end of 2021. In 2022, upon filing of the new actuarial funding valuations, the company entered into another contribution holiday for the defined benefit plans with the company anticipating to fully resume cash contributions in 2024.

Of the total net obligations as at December 31, 2022, 96% relates to Canadian pension plans and other post-retirement benefits obligation (December 31, 2021 – 98%). The weighted average duration of the defined benefit obligation under the Canadian pension plans and other post-retirement plans is 16.4 years (2021 – 15.1 years).

($ millions)	Pension Benefits 2022	2021	Other Post-Retirement Benefits 2022	2021
Analysis of amount charged to earnings:				
Current service costs	**263**	302	**19**	19
Interest costs	**21**	41	**20**	18
Defined benefit plans expense	**284**	343	**39**	37
Defined contribution plans expense	**95**	94	**-**	-
Total benefit plans expense charged to earnings	**379**	437	**39**	37

Components of defined benefit costs recognized in Other Comprehensive Income:

($ millions)	Pension Benefits 2022	2021	Other Post-Retirement Benefits 2022	2021
Actuarial (gain) / loss arising from changes in experience	**(86)**	(1)	**3**	(1)
Actuarial gain arising from changes in financial assumptions	**(2 229)**	(572)	**(167)**	(27)
Actuarial gain arising from changes in demographic assumptions	**-**	(2)	**-**	-
Benefit Obligation gains	**(2 315)**	(575)	**(164)**	(28)
Return on plan assets (greater) / less than discount rate (excluding amounts included in net interest expense)	**1 190**	(530)	**-**	-
Effect of the asset ceiling	**187**	-	**-**	-
Plan assets loss / (gain)	**1 377**	(530)	**-**	-
Actuarial gain recognized in other comprehensive income	**(938)**	(1 105)	**(164)**	(28)

Actuarial Assumptions

The cost of the defined benefit pension plans and other post-retirement benefits received by employees is actuarially determined using the projected unit credit method of valuation that includes employee service to date and present pay levels, as well as the projection of salaries and service to retirement.

The significant weighted average actuarial assumptions were as follows:

(%)	Pension Benefits December 31 2022	December 31 2021	Other Post-Retirement Benefits December 31 2022	December 31 2021
Discount rate	**5.10**	2.90	**5.10**	2.90
Rate of compensation increase	**3.00**	3.00	**3.00**	3.00

The discount rate assumption is based on the interest rate on high-quality bonds with maturity terms equivalent to the benefit obligations.

The defined benefit obligation reflects the best estimate of the mortality of plan participants both during and after their employment. The mortality assumption is based on a standard mortality table adjusted for actual experience over the past five years.

In order to measure the expected cost of other post-retirement benefits, it was assumed that the health care costs would increase annually by 5%.

Assumed discount rates and health care cost trend rates may have a significant effect on the amounts reported for pensions and other post-retirement benefits obligations for the company's Canadian plans. A change of these assumptions would have the following effects:

($ millions)	Pension Benefits Increase	Pension Benefits Decrease
1% change in discount rate		
Effect on the aggregate service and interest costs	(25)	32
Effect on the benefit obligations	(693)	871

($ millions)	Other Post-Retirement Benefits Increase	Other Post-Retirement Benefits Decrease
1% change in discount rate		
Effect on the benefit obligations	(53)	64
1% change in health care cost		
Effect on the aggregate service and interest costs	1	(1)
Effect on the benefit obligations	27	(23)

Plan Assets and Investment Objectives

The company's long-term investment objective is to secure the defined pension benefits while managing the variability and level of its contributions. The portfolio is rebalanced periodically, as required, to the plans' target asset allocation as prescribed in the Statement of Investment Policies and Procedures approved by the Board of Directors. Plan assets are restricted to those permitted by legislation, where applicable. Investments are made through pooled, mutual, segregated or exchange traded funds.

The company's weighted average pension plan asset allocations, based on market values as at December 31, are as follows:

(%)	2022	2021
Equities	**52**	48
Fixed income	**27**	38
Plan assets, comprised of:		
– Real Estate	**21**	14
Total	**100**	100

Equity securities do not include any direct investments in Suncor shares. The fair value of equity and fixed income securities is based on the trading price of the underlying fund. The fair value of real estate investments is based on independent third-party appraisals.

24. Provisions

($ millions)	Decommissioning and Restoration[1]	Royalties	Other[2]	Total
At December 31, 2020	10 044	71	467	10 582
Liabilities incurred	104	137	171	412
Change in discount rate	(1 260)	-	-	(1 260)
Changes in estimates	(76)	(12)	(13)	(101)
Liabilities settled	(263)	26	(84)	(321)
Accretion	304	-	-	304
Foreign exchange	(61)	-	-	(61)
At December 31, 2021	8 792	222	541	9 555
Less: current portion	(266)	(222)	(291)	(779)
	8 526	-	250	8 776
At December 31, 2021	8 792	222	541	9 555
Liabilities incurred	**114**	**89**	**3**	**206**
Change in discount rate	**(2 456)**	**-**	**-**	**(2 456)**
Changes in estimates	**3 596**	**(4)**	**69**	**3 661**
Liabilities settled	**(314)**	**(125)**	**(332)**	**(771)**
Accretion	**316**	**-**	**-**	**316**
Asset disposals	**62**	**-**	**-**	**62**
Reclassified to assets held for sale (note 33)	**(226)**	**-**	**-**	**(226)**
Foreign exchange	**17**	**-**	**-**	**17**
At December 31, 2022	**9 901**	**182**	**281**	**10 364**
Less: current portion	**(337)**	**(182)**	**(45)**	**(564)**
	9 564	**-**	**236**	**9 800**

(1) Represents decommissioning and restoration provisions associated with the retirement of Property, Plant and Equipment and Exploration and Evaluation assets. The total undiscounted and uninflated amount of estimated future cash flows required to settle the obligations at December 31, 2022 was approximately $22.4 billion (December 31, 2021 – $13.8 billion). A $3.6 billion increase in the estimated discounted cash flows was recognized at December 31, 2022, and was primarily related to water treatment costs for mining assets. A weighted average credit-adjusted risk-free interest rate of 5.50% was used to discount the provision recognized at December 31, 2022 (December 31, 2021 – 3.70%). The credit-adjusted risk-free interest rate used reflects the expected time frame of the provisions. Payments to settle the decommissioning and restoration provisions occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 50 years.

(2) Includes legal and environmental provisions, a restructuring provision remaining for $11 million (December 31, 2021 - $88 million). Liabilities settled in 2022 include a payment to the Keystone XL pipeline project for $187 million (after-tax $142 million).

Sensitivities

Changes to the discount rate would have the following impact on Decommissioning and Restoration liabilities:

As at December 31	**2022**	2021
1% Increase	**(1 594)**	(1 497)
1% Decrease	**2 131**	2 113

25. Share Capital

Authorized

Common Shares

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares

The company is authorized to issue an unlimited number of senior and junior preferred shares in series, without nominal or par value.

Normal Course Issuer Bid

During the first quarter of 2022, the TSX accepted a notice filed by Suncor to renew its normal course issuer bid (NCIB) to purchase the company's common shares through the facilities of the TSX, New York Stock Exchange (NYSE) and/or alternative trading systems. The notice provided that, beginning February 8, 2022, and ending February 7, 2023, Suncor may purchase for cancellation up to 71,650,000 common shares, which is equal to approximately 5% of Suncor's issued and outstanding common shares as at the date hereof.

During the second quarter of 2022, Suncor received approval from the TSX to amend its existing NCIB effective as of the close of markets on May 11, 2022, to increase the maximum number of common shares that may be repurchased in the period beginning February 8, 2022, and ending February 7, 2023, from 71,650,000 common shares, or approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2022, to 143,500,000, or approximately 10% of Suncor's public float as at January 31, 2022. No other terms of the NCIB were amended.

For the twelve months ended December 31, 2022, the company repurchased 7.1 million common shares under the previous 2021 NCIB and 109.8 million under the 2022 renewed NCIB at an average price of $43.92 per share, for a total repurchase cost of $5.1 billion.

Subsequent to the fourth quarter of 2022, the TSX accepted a notice filed by Suncor to renew its NCIB to purchase the company's common shares through the facilities of the TSX, NYSE and/or alternative trading systems. The notice provides that, beginning February 17, 2023, and ending February 16, 2024, Suncor may purchase for cancellation up to 132,900,000 common shares, which is equal to approximately 10% of Suncor's public float as at February 3, 2023. As at February 3, 2023, Suncor had 1,330,006,760 common shares issued and outstanding.

During the first quarter of 2021, the company announced its intention to commence a new Normal Course Issuer Bid (the 2021 NCIB) to repurchase common shares through the facilities of the TSX, NYSE and/or alternative trading systems. Pursuant to the 2021 NCIB, the company may repurchase for cancellation up to 44,000,000 common shares between February 8, 2021, and February 7, 2022.

During the third quarter of 2021, Suncor received approval from the TSX to amend the 2021 NCIB effective as of the close of markets on July 30, 2021. The amended notice provides that Suncor may increase the maximum number of common shares that may be repurchased under the 2021 NCIB from February 8, 2021, and ending February 7, 2022, from 44,000,000 common shares, or approximately 2.9% of Suncor's issued and outstanding common shares as at January 31, 2021, to 76,250,000 common shares, or approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2021. No other terms of the NCIB were amended.

During the fourth quarter of 2021, Suncor received approval from the TSX to amend its existing NCIB effective as of the close of markets on October 29, 2021. The notice provides that Suncor may increase the maximum number of common shares that may be repurchased in the period beginning February 8, 2021, and ending February 7, 2022, from 76,250,000 shares, or approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2021, to 106,700,000, or approximately 7% of Suncor's public float as at January 31, 2021. No other terms of the NCIB were amended.

For the twelve months ended December 31, 2021, the company repurchased 84.0 million common shares under the 2021 NCIB at an average price of $27.45 per share, for a total repurchase cost of $ 2.3 billion.

The following table summarizes the share repurchase activities during the period:

($ millions, except as noted)	**2022**	2021
Share repurchase activities (thousands of common shares)		
Shares repurchased	**116 908**	83 959
Amounts charged to		
Share capital	**1 947**	1 382
Retained earnings	**3 188**	922
Share repurchase cost	**5 135**	2 304
Average repurchase cost per share	**43.92**	27.45

Under an automatic repurchase plan agreement with an independent broker, the company has recorded the following liability for share repurchases that may take place during its internal blackout period:

($ millions)	December 31 2022	December 31 2021
Amounts charged to		
Share capital	**136**	120
Retained earnings	**214**	110
Liability for share purchase commitment	**350**	230

26. Share-Based Compensation

Share-Based Compensation Expense

Included in the Consolidated Statements of Comprehensive Income within Operating, Selling and General expense are the following share-based compensation amounts:

($ millions)	2022	2021
Equity-settled plans	**17**	21
Cash-settled plans	**484**	301
Total share-based compensation expense	**501**	322

Liability Recognized for Share-Based Compensation

Included in the Consolidated Balance Sheets within accounts payable and accrued liabilities and other long-term liabilities are the following fair value amounts for the company's cash-settled plans:

($ millions)	December 31 2022	December 31 2021
Current liability	**326**	153
Long-term liability (note 22)	**469**	291
Total Liability	**795**	444

The intrinsic value of the vested awards at December 31, 2022 was $ 415 million (December 31, 2021 – $200 million).

Stock Option Plans

Suncor grants stock option awards as a form of retention and incentive compensation.

Stock options granted by the company provide the holder with the right to purchase common shares at the market price on the grant date, subject to fulfilling vesting terms. Options granted have a seven-year life, vest annually over a three-year period and are accounted for as equity-settled awards.

The weighted average fair value of options granted during the period and the weighted average assumptions used in their determination are as noted below:

	2022	2021
Annual dividend per share (dollars)	**1.88**	1.05
Risk-free interest rate	**1.73%**	0.49%
Expected life	**5 years**	5 years
Expected volatility	**42%**	40%
Weighted average fair value per option (dollars)	**9.27**	5.40

The expected life is based on historical stock option exercise data and current expectations. The expected volatility considers the historical volatility in the price of Suncor's common shares over a period similar to the life of the options, and is indicative of future trends.

The following table presents a summary of the activity related to Suncor's stock option plans:

	2022		2021	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**37 090**	**38.39**	38 373	39.65
Granted	**2 191**	**37.22**	3 457	22.71
Exercised as options for common shares	**(13 158)**	**37.69**	(245)	29.82
Forfeited/expired	**(5 055)**	**38.99**	(4 495)	37.62
Outstanding, end of year	**21 068**	**38.55**	37 090	38.39
Exercisable, end of year	**16 407**	**40.19**	28 421	39.87

For the options outstanding at December 31, 2022, the exercise price ranges and weighted average remaining contractual lives are shown below:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)	Number (thousands)	Weighted Average Exercise Price ($)
22.63-24.99	**2 658**	5	22.65	**1 064**	22.65
25.00-29.99	**9**	5	29.31	**3**	29.34
30.00-34.99	**731**	-	30.30	**718**	30.28
35.00-39.99	**6 176**	4	38.37	**3 255**	38.85
40.00-44.99	**11 298**	2	42.73	**11 235**	42.75
45.00-49.99	**101**	5	48.05	**44**	48.41
50.00-54.27	**95**	3	52.78	**88**	52.85
Total	**21 068**	3	38.55	**16 407**	40.19

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options:

(thousands)	**2022**	2021
	27 901	25 037

Share Unit Plans

Suncor grants share units as a form of retention and incentive compensation. Share unit plans are accounted for as cash-settled awards.

(a) Performance Share Units (PSUs)

A PSU is a time-vested award entitling employees to receive varying degrees of cash (0%–200% of the company's share price at time of vesting) contingent upon Suncor's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. Cash payments for awards granted in 2019 and onwards are contingent upon Suncor's total shareholder return and annual return on capital employed performance. PSUs vest approximately three years after the grant date.

(b) Restricted Share Units (RSUs)

A RSU is a time-vested award entitling employees to receive cash calculated based on an average of the company's share price leading up to vesting. RSUs vest approximately three years after the grant date.

In 2022, Syncrude's Long Term Incentive Plans (LTIP) of approximately $ 123 million were converted into Suncor RSUs at a conversion price of $30.93.

(c) Deferred Share Units (DSUs)

A DSU is redeemable for cash or a common share for a period of time after a unitholder ceases employment or Board membership. The DSU Plan is limited to executives and members of the Board of Directors. Members of the Board of Directors receive an annual grant of DSUs as part of their compensation and may elect to receive their fees in cash only or in increments of 50% or 100% allocated to DSUs. Executives may elect to receive their annual incentive bonus in cash only or in increments of 25%, 50%, 75% or 100% allocated to DSUs.

The following table presents a summary of the activity related to Suncor's share unit plans:

(thousands)	PSU	RSU	DSU
Outstanding, December 31, 2020	2 285	15 095	1 385
Granted	1 285	11 954	164
Redeemed for cash	(751)	(4 609)	(167)
Forfeited/expired	(53)	(1 003)	-
Outstanding, December 31, 2021	2 766	21 437	1 382
Granted	**947**	**13 235**	**187**
Redeemed for cash	**(794)**	**(4 533)**	**(238)**
Forfeited/expired	**(710)**	**(1 877)**	**-**
Outstanding, December 31, 2022	**2 209**	**28 262**	**1 331**

Stock Appreciation Rights (SARs)

A SAR entitles the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of the company's common shares on the date the SAR is exercised, and is accounted for as a cash-settled award.

SARs have a seven-year life and vest annually over a three-year period.

	2022		2021	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**463**	**39.06**	509	39.25
Granted	**10**	**36.76**	10	22.63
Exercised	**(121)**	**37.18**	—	—
Forfeited/expired	**(65)**	**38.25**	(56)	37.78
Outstanding, end of year	**287**	**39.95**	463	39.06
Exercisable, end of year	**242**	**40.82**	357	39.68

27. Financial Instruments and Risk Management

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all accounts payable and accrued liabilities, debt, and certain portions of other assets and other long-term liabilities.

Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable, short-term debt, and accounts payable and accrued liabilities approximate their carrying values due to the short-term maturities of those instruments.

The company's long-term debt and long-term financial liabilities are recorded at amortized cost using the effective interest method. At December 31, 2022, the carrying value of fixed-term debt accounted for under amortized cost was $9.8 billion (December 31, 2021 – $14.2 billion) and the fair value at December 31, 2022 was $ 9.4 billion (December 31, 2021 – $17.4 billion). The decrease in carrying value and fair value of debt is mainly due to repayment of debt during the year. The estimated fair value of long-term debt is based on pricing sourced from market data, which is considered a Level 2 fair value input.

Suncor entered into a partnership with Fort McKay First Nation (FMFN) and Mikisew Cree First Nation (MCFN) in 2018 where FMFN and MCFN acquired a combined 49% partnership interest in the East Tank Farm Development. The partnership liability is recorded at amortized cost using the effective interest method. At December 31, 2022, the carrying value of the Partnership liability accounted for under amortized cost was $427 million (December 31, 2021 – $436 million).

Derivative Financial Instruments

(a) Non-Designated Derivative Financial Instruments

The company uses derivative financial instruments, such as physical and financial contracts, to manage certain exposures to fluctuations in interest rates, commodity prices and foreign currency exchange rates, as part of its overall risk management program, as well as for trading purposes.

The changes in the fair value of non-designated derivatives are as follows:

($ millions)	2022	2021
Fair value outstanding, beginning of year	**(98)**	(121)
Cash settlements – paid during the year	**220**	178
Changes in fair value recognized in earnings during the year (note 7)	**(187)**	(155)
Fair value outstanding, end of year	**(65)**	(98)

(b) Fair Value Hierarchy

To estimate the fair value of derivatives, the company uses quoted market prices when available, or third-party models and valuation methodologies that utilize observable market data. In addition to market information, the company incorporates transaction-specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 consists of instruments with a fair value determined by an unadjusted quoted price in an active market for identical assets or liabilities. An active market is characterized by readily and regularly available quoted prices where the prices are representative of actual and regularly occurring market transactions to assure liquidity.

- Level 2 consists of instruments with a fair value that is determined by quoted prices in an inactive market, prices with observable inputs, or prices with insignificant non-observable inputs. The fair value of these positions is determined using observable inputs from exchanges, pricing services, third-party independent broker quotes, and published transportation tolls. The observable inputs may be adjusted using certain methods, which include extrapolation over the quoted price term and quotes for comparable assets and liabilities.

- Level 3 consists of instruments with a fair value that is determined by prices with significant unobservable inputs. As at December 31, 2022, the company does not have any derivative instruments measured at fair value Level 3.

In forming estimates, the company utilizes the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorized based upon the lowest level of input that is significant to the fair value measurement.

The following table presents the company's derivative financial instrument assets and liabilities measured at fair value for each hierarchy level as at December 31, 2022 and 2021.

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	35	88	-	123
Accounts payable	(134)	(87)	-	(221)
Balance at December 31, 2021	(99)	1	-	(98)
Accounts receivable	**36**	**107**	**-**	**143**
Accounts payable	**(85)**	**(123)**	**-**	**(208)**
Balance at December 31, 2022	**(49)**	**(16)**	**-**	**(65)**

During the year ended December 31, 2022, there were no transfers between Level 1 and Level 2 fair value measurements.

Offsetting Financial Assets and Liabilities

The company enters into arrangements that allow for offsetting of derivative financial instruments and accounts receivable (payable), which are presented on a net basis on the balance sheet, as shown in the table below as at December 31, 2022 and 2021.

Financial Assets

($ millions)	Gross Assets	Gross Liabilities Offset	Net Amounts Presented
Fair value of derivative assets	6 527	(6 404)	123
Accounts receivable	5 048	(2 734)	2 314
Balance at December 31, 2021	11 575	(9 138)	2 437
Fair value of derivative assets	**4 305**	**(4 162)**	**143**
Accounts receivable	**10 349**	**(8 633)**	**1 716**
Balance at December 31, 2022	**14 654**	**(12 795)**	**1 859**

Financial Liabilities

($ millions)	Gross Liabilities	Gross Assets Offset	Net Amounts Presented
Fair value of derivative liabilities	(6 625)	6 404	(221)
Accounts payable	(4 205)	2 734	(1 471)
Balance at December 31, 2021	(10 830)	9 138	(1 692)
Fair value of derivative liabilities	**(4 370)**	**4 162**	**(208)**
Accounts payable	**(10 036)**	**8 633**	**(1 403)**
Balance at December 31, 2022	**(14 406)**	**12 795**	**(1 611)**

Risk Management

The company is exposed to a number of different risks arising from financial instruments. These risk factors include market risks, comprising commodity price risk, foreign currency risk and interest rate risk, as well as liquidity risk and credit risk.

The company maintains a formal governance process to manage its financial risks. The company's Commodity Risk Management Committee (CRMC) is charged with the oversight of the company's trading and credit risk management activities. These activities are intended to manage risk associated with open price exposure of specific volumes in transit or storage, enhance the company's operations, and enhance profitability through informed market calls, market diversification,

economies of scale, improved transportation access, and leverage of assets, both physical and contractual. The CRMC, acting under the authority of the company's Board of Directors, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures.

1) Market Risk

Market risk is the risk or uncertainty arising from market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the company's financial assets, liabilities and expected future cash flows include commodity price risk, foreign currency exchange risk and interest rate risk.

(a) Commodity Price Risk

Suncor's financial performance is closely linked to crude oil and refined product prices (including pricing differentials for various product types) and, to a lesser extent, natural gas and electricity prices. The company may reduce its exposure to commodity price risk through a number of strategies. These strategies include entering into derivative contracts to limit exposure to changes in crude oil and refined product prices during transportation and natural gas prices.

An increase of US$10/bbl of crude oil as at December 31, 2022 would increase pre-tax earnings for the company's outstanding derivative financial instruments by approximately $70 million (2021 – $58 million increase).

(b) Foreign Currency Exchange Risk

The company is exposed to foreign currency exchange risk on revenues, capital expenditures, or financial instruments that are denominated in a currency other than the company's functional currency (Canadian dollars). As crude oil is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. This exposure is partially offset through the issuance of U.S. dollar denominated debt. A 1% strengthening in the Cdn$ relative to the US$ as at December 31, 2022 would increase pre-tax earnings related to the company's U.S. dollar denominated long-term debt, commercial paper and working capital by approximately $100 million (2021 – $133 million).

(c) Interest Rate Risk

The company is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair values of its financial instruments. The primary exposure is related to its revolving-term debt of commercial paper and future debt issuances.

To manage the company's exposure to interest rate volatility, the company may periodically enter into interest rate swap contracts to fix the interest rate of future debt issuances. As at December 31, 2022, the company had no outstanding forward interest rate swaps. The simple average interest rate on total debt, including lease liabilities, for the year ended December 31, 2022 was 5.8% (2021 – 5.0%).

The company's net earnings are sensitive to changes in interest rates on the floating rate portion of the company's debt, which are offset by cash balances. To the extent interest expense is not capitalized, if interest rates applicable to floating rate instruments increased by 1%, it is estimated that the company's pre-tax earnings would decrease by approximately $ 8 million primarily due to a lower cash balance compared to the short-term debt balance (2021 – approximately $9 million increase). This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2022. The proportion of floating interest rate exposure at December 31, 2022 was 18.0% of total debt outstanding (2021 – 7.0%).

2) Liquidity Risk

Liquidity risk is the risk that Suncor will not be able to meet its financial obligations when due. The company mitigates this risk by forecasting spending requirements as well as cash flow from operating activities, and maintaining sufficient cash, credit facilities, and debt shelf prospectuses to meet these requirements. Suncor's cash and cash equivalents and total credit facilities at December 31, 2022 were $2.0 billion and $7.2 billion, respectively. Of Suncor's $7.2 billion in total credit facilities, $3.3 billion were unutilized at December 31, 2022. In addition, Suncor has unused capacity under the Board of Directors authority of US$5.0 billion to issue debt. The ability of the company to raise additional capital utilizing these shelf prospectuses is dependent on market conditions. The company believes it has sufficient funding through the use of these facilities and access to capital markets to meet its future capital requirements.

Surplus cash is invested into a range of short-dated money market securities. Investments are only permitted in high credit quality government or corporate securities. Diversification of these investments is managed through counterparty credit limits.

The following table shows the timing of cash outflows related to trade and other payables and debt.

	December 31, 2021			
($ millions)	Trade and Other Payables(1)	Gross Derivative Liabilities(2)	Debt(3)	Lease Liabilities
Within one year	6 282	6 466	2 253	459
2 to 3 years	37	159	2 015	779
4 to 5 years	37	-	3 127	660
Over 5 years	-	-	18 836	2 633
	6 356	6 625	26 231	4 531

	December 31, 2022			
($ millions)	**Trade and Other Payables(1)**	**Gross Derivative Liabilities(2)**	**Debt(3)**	**Lease Liabilities**
Within one year	**7 959**	**3 824**	**3 375**	**477**
2 to 3 years	**39**	**546**	**1 066**	**807**
4 to 5 years	**39**	**-**	**1 541**	**652**
Over 5 years	**-**	**-**	**16 317**	**3 047**
	8 037	**4 370**	**22 299**	**4 983**

(1) Trade and other payables exclude net derivative liabilities of $208 million (2021 – $221 million).

(2) Gross derivative liabilities of $4.370 billion (2021 – $6.625 billion) are offset by gross derivative assets of $4.162 billion (2021 – $6.404 billion), resulting in a net amount of $208 million (2021 – $221 million).

(3) Debt includes short-term debt, long-term debt and interest payments on fixed-term debt.

3) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due, causing a financial loss. The company's credit policy is designed to ensure there is a standard credit practice throughout the company to measure and monitor credit risk. The policy outlines delegation of authority, the due diligence process required to approve a new customer or counterparty and the maximum amount of credit exposure per single entity. Before transactions begin with a new customer or counterparty, its creditworthiness is assessed, and a credit rating and a maximum credit limit are assigned. The assessment process is outlined in the credit policy and considers both quantitative and qualitative factors. The company constantly monitors the exposure to any single customer or counterparty along with the financial position of the customer or counterparty. If it is deemed that a customer or counterparty has become materially weaker, the company will work to reduce the credit exposure and lower the assigned credit limit. Regular reports are generated to monitor credit risk and the Credit Committee meets quarterly to ensure compliance with the credit policy and review the exposures.

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. At December 31, 2022, substantially all of the company's trade receivables were current.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts owing to the company at the reporting date. At December 31, 2022, the company's net exposure was $143 million (December 31, 2021 – $123 million).

28. Capital Structure Financial Policies

The company's primary capital management strategy is to maintain a conservative balance sheet, which supports a solid investment grade credit rating profile. This objective affords the company the financial flexibility and access to the capital it requires to execute on its growth objectives.

The company's capital is primarily monitored by reviewing the ratios of net debt to adjusted funds from operations (2) and total debt to total debt plus shareholders' equity.

Net debt to adjusted funds from operations (2) is calculated as short-term debt plus total long-term debt less cash and cash equivalents, divided by adjusted funds from operations for the year then ended.

Total debt to total debt plus shareholders' equity is calculated as short-term debt plus total long-term debt divided by short-term debt plus total long-term debt plus shareholders' equity. This financial covenant under the company's various banking and debt agreements shall not be greater than 65%.

The company's financial covenant is reviewed regularly and controls are in place to maintain compliance with the covenant. The company complied with financial covenants for the years ended December 31, 2022 and 2021. The company's financial measures, as set out in the following schedule, were unchanged from 2021. The company believes that achieving its capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment grade credit ratings. Total debt to total debt plus shareholders' equity was 28.4% at December 31, 2022 and decreased due to lower debt levels and higher shareholders' equity as a result of increased net earnings. The company operates in a fluctuating business environment and ratios may periodically fall outside of management's targets. The company addresses these fluctuations by capital expenditure reductions and sales of non-core assets to ensure net debt achieves management's targets.

($ millions)	Capital Measure Target	**December 31 2022**	December 31 2021
Components of ratios			
Short-term debt		**2 807**	1 284
Current portion of long-term debt		**-**	231
Current portion of long-term lease liabilities		**317**	310
Long-term debt		**9 800**	13 989
Long-term lease liabilities		**2 695**	2 540
Total debt(1)		**15 619**	18 354
Less: Cash and cash equivalents		**1 980**	2 205
Net debt(1)		**13 639**	16 149
Shareholders' equity		**39 367**	36 614
Total capitalization (total debt plus shareholders' equity)		**54 986**	54 968
Adjusted funds from operations (2)		**18 101**	10 257
Net debt to adjusted funds from operations	<3.0 times	**0.8**	1.6
Total debt to total debt plus shareholders' equity	20% - 35%	**28.4%**	33.4%

(1) Total debt and net debt are non-GAAP financial measures.

(2) Adjusted funds from operations is calculated as cash flow from operating activities before changes in non-cash working capital, and is a non-GAAP financial measure.

Table of Contents

29. Joint Arrangements

Joint Operations

The company's material joint operations as at December 31 are set out below:

Material Joint Operations	Principal Activity	Country of Incorporation and Principal Place of Business	**Ownership % 2022**	Ownership % 2021
Oil Sands				
Operated by Suncor:				
Fort Hills Energy Limited Partnership[1]	Oil sands development	Canada	**54.11**	54.11
Meadow Creek	Oil sands development	Canada	**75.00**	75.00
Syncrude	Oil sands development	Canada	**58.74**	58.74
Exploration and Production				
Operated by Suncor:				
Terra Nova	Oil and gas production	Canada	**48.00**	48.00
Non-operated:				
Buzzard[2]	Oil and gas production	United Kingdom	**29.89**	29.89
Fenja Development JV[3]	Oil and gas production	Norway	**—**	17.50
Hibernia and the Hibernia South Extension Unit	Oil and gas production	Canada	**19.48-20.00**	19.48-20.00
Hebron	Oil and gas production	Canada	**21.03**	21.03
Harouge Oil Operations	Oil and gas production	Libya	**49.00**	49.00
North Sea Rosebank Project[2]	Oil and gas production	United Kingdom	**40.00**	40.00
Oda[3]	Oil and gas production	Norway	**—**	30.00
White Rose and the White Rose Extensions[4]	Oil and gas production	Canada	**38.625-40.00**	26.13-27.50

(1) Subsequent to December 31, 2022, Suncor acquired an additional 14.65% working interest in Fort Hills, bringing the company's and its affiliate's total aggregate working interest to 68.76%.

(2) In the third quarter of 2022, Suncor reclassified the assets and liabilities related to its United Kingdom (U.K.) operations as assets held for sale, including its interests in Buzzard and Rosebank. Subsequent to the fourth quarter of 2022, the company reached an agreement for the sale of its U.K operations. The sale is expected to close in mid-2023.

(3) In the third quarter of 2022, Suncor completed the sale of its Norway assets, including its 30% working interest in Oda and its 17.5% working interest in the Fenja Development Joint Operations.

(4) In the second quarter of 2022, Suncor announced that concurrent with the decision to restart the West White Rose project by the joint venture owners, Suncor increased its ownership in the White Rose asset 12.50% to approximately 40.00%.

Joint Ventures and Associates

The company does not have any joint ventures or associates that are considered individually material. Summarized aggregate financial information of the joint ventures and associates, which are all included in the company's Refining and Marketing operations, are shown below:

	Joint ventures		Associates	
($ millions)	**2022**	2021	**2022**	2021
Net earnings (loss)	**(25)**	5	**(1)**	(2)
Total comprehensive earnings (loss)	**(25)**	5	**(1)**	(2)
Carrying amount as at December 31	**39**	63	**63**	66

30. Subsidiaries

Material subsidiaries, either directly or indirectly, by the company as at December 31, 2022 are shown below:

Material Subsidiaries	Principal Activity
Canadian Operations	
Suncor Energy Oil Sands Limited Partnership	This partnership holds most of the company's Oil Sands operations assets.
Suncor Energy Ventures Corporation	A subsidiary which indirectly owns a 36.74% ownership in the Syncrude joint operation.
Suncor Energy Ventures Partnership	A subsidiary which owns a 22% ownership in the Syncrude joint operation.
Suncor Energy Products Partnership	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Marketing Inc.	Through this subsidiary, production from the upstream Canadian businesses is marketed. This subsidiary also administers Suncor's energy trading activities and power business, markets certain third-party products, procures crude oil feedstock and natural gas for its downstream business, and procures and markets natural gas liquids (NGLs) and liquefied petroleum gas (LPG) for its downstream business.
U.S. Operations	
Suncor Energy (U.S.A.) Marketing Inc.	A subsidiary that procures, markets and trades crude oil, in addition to procuring crude oil feedstock for the company's refining operations.
Suncor Energy (U.S.A.) Inc.	A subsidiary through which the company's U.S. refining and marketing operations are conducted.
International Operations	
Suncor Energy UK Limited	A subsidiary through which the majority of the company's North Sea operations are conducted.

The table does not include wholly owned subsidiaries that are immediate holding companies of the operating subsidiaries. For certain foreign operations of the company, there are restrictions on the sale or transfer of production licences, which would require approval of the applicable foreign government.

31. Related Party Disclosures

Related Party Transactions

The company enters into transactions with related parties in the normal course of business, which includes purchases of feedstock, distribution of refined products, and the sale of refined products and byproducts. These transactions are with joint ventures and associated entities in the company's Refining and Marketing operations, including pipeline, refined product and petrochemical companies. A summary of the significant related party transactions as at and for the years ended December 31, 2022 and 2021 are as follows:

($ millions)	**2022**	2021
Sales[1]	**1 616**	1 011
Purchases	**265**	247
Accounts receivable	**135**	70
Accounts payable and accrued liabilities	**69**	17

(1) Includes sales to Petroles Cadeko Inc. of $645 million (2021 - $411 million) and Parachem Chemicals Inc. of $487 million (2021 – $343 million).

Compensation of Key Management Personnel

Compensation of the company's Board of Directors and members of the Executive Leadership Team for the years ended December 31 is as follows:

($ millions)	**2022**	2021
Salaries and other short-term benefits	**20**	8
Pension and other post-retirement benefits	**4**	3
Share based compensation	**73**	47
	97	58

32. Commitments, Contingencies and Guarantees

(a) Commitments

Future payments under the company's commitments, including service arrangements for pipeline transportation agreements and for other property and equipment, are as follows:

	Payment Due by Period						
($ millions)	2023	2024	2025	2026	2027	Thereafter	**Total**
Commitments							
Product transportation and storage	1 146	1 252	1 201	1 024	1 165	7 410	**13 198**
Energy services	101	101	119	77	71	77	**546**
Exploration work commitments	-	-	53	1	-	486	**540**
Other	471	269	149	115	73	191	**1 268**
	1 718	1 622	1 522	1 217	1 309	8 164	**15 552**

In addition to the commitments in the above table, the company has other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Such obligations include commodity purchase obligations which are transacted at market prices.

(b) Contingencies

Legal and Environmental Contingent Liabilities and Assets

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities or assets that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

The company may also have environmental contingent liabilities, beyond decommissioning and restoration liabilities (recognized in note 24), which are reviewed individually and are reflected in the company's consolidated financial statements if material and more likely than not to be incurred. These contingent environmental liabilities primarily relate to the mitigation of contamination at sites where the company has had operations. For any unrecognized environmental contingencies, the company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash flow from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact is not expected to be material.

Contingent assets are only disclosed when the inflow of economic benefits is probable. When the economic benefit becomes virtually certain, the asset is no longer contingent and is recognized in the consolidated financial statements.

(c) Guarantees

At December 31, 2022, the company has provided loan guarantees to certain retail licensees and wholesale marketers. Suncor's maximum potential amount payable under these loan guarantees is $125 million.

The company has also agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 21) for added costs relating to withholding taxes. Similar indemnity terms apply to certain facility and equipment leases. There is no limit to the maximum amount payable under these indemnification agreements. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, the company has the option to redeem or terminate these contracts if additional costs are incurred.

The company also has guaranteed its working-interest share of certain joint operation undertakings related to transportation services agreements entered into with third parties. The guaranteed amount is limited to the company's share in the joint arrangement. As at December 31, 2022, the probability is remote that these guarantee commitments will impact the company.

33. Assets Held for Sale

In the third quarter of 2022, the company reclassified the assets and liabilities related to its United Kingdom (U.K.) operations, including its interests in Buzzard and Rosebank located in the U.K. sector of the North Sea. The U.K. operations are reported within the Exploration and Production segment.

Subsequent to the fourth quarter of 2022, on March 2, 2023, the company reached an agreement for the sale of its U.K. operations for gross proceeds of approximately $1.2 billion, including a contingent consideration of approximately $338 million, before closing adjustments and other closing costs. The sale is pending regulatory approval, and is expected to close in mid-2023.

The table below details the assets and liabilities held for sale as at December 31, 2022:

($ millions)	
Assets	
Currents assets	**83**
Property, plant and equipment, net	**364**
Exploration and evaluation	**239**

Total Assets	**686**
Liabilities	
Current liabilities	**(241)**
Provisions	**(217)**
Total Liabilities	**(458)**
Net Assets	**228**

Subsequent to the fourth quarter of 2022, the company completed the sale of its wind and solar assets (Forty Mile, Adelaide, Magrath and Chin Chute) for gross proceeds of approximately $730 million, before closing adjustments and other closing costs, resulting in an estimated after-tax gain on sale of approximately $260 million. The company completed the sale of its Forty Mile and Adelaide assets on January 3, 2023 and its Magrath and Chin Chute assets on January 10, 2023. The renewable energy business is reported within the Corporate segment.

The table below details the assets and liabilities held for sale as at December 31, 2022:

($ millions)	
Assets	
Current assets	**62**
Property, plant and equipment, net and intangible assets	**438**
Total Assets	**500**
Liabilities	
Current liabilities	**(32)**
Other long-term liabilities and provisions	**(40)**
Total Liabilities	**(72)**
Net Assets	**428**

Exhibit 99-3

Management's Discussion and Analysis

March 6, 2023

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's December 31, 2022 audited Consolidated Financial Statements and the accompanying notes. Additional information about Suncor filed with Canadian securities regulatory authorities and the United States Securities and Exchange Commission (SEC), including quarterly and annual reports and Suncor's Annual Information Form dated March 6, 2023 (the 2022 AIF), which is also filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and on our website at www.suncor.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A and is not incorporated by reference into this MD&A.

Suncor Energy Inc. has numerous direct and indirect subsidiaries, partnerships, and joint arrangements (collectively, affiliates), which own and operate assets and conduct activities in different jurisdictions. The terms ''we'', ''our'', ''Suncor'' or ''the company'' are used herein for simplicity of communication and only mean there is an affiliation with Suncor Energy Inc., without necessarily identifying the specific nature of the affiliation. The use of such terms in any statement herein does not mean they apply to Suncor Energy Inc. or any particular affiliate and does not waive the corporate separateness of any affiliate. For further clarity, Suncor Energy Inc. does not directly operate or own assets in the U.S. For a list of abbreviations that may be used in this MD&A, refer to the Advisories – Common Abbreviations section of this MD&A.

Table of Contents

MD&A – Table of Contents

3	Financial and Operating Summary
6	Suncor Overview
11	Financial Information
17	Segment Results and Analysis
38	Income Tax
38	Fourth Quarter 2022 Analysis
42	Quarterly Financial Data
45	Capital Investment Update
48	Financial Condition and Liquidity
54	Accounting Policies and Critical Accounting Estimates
57	Risk Factors
70	Other Items
71	Advisories

Basis of Presentation

Unless otherwise noted, all financial information contained herein has been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

All financial information is reported in Canadian dollars, unless otherwise noted. Production volumes are presented on a working-interest basis, before royalties, except for production volumes from the company's Libya operations, which are presented on an economic basis.

References to Oil Sands operations exclude Suncor's interests in Fort Hills and Syncrude.

Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated net earnings (loss), adjusted operating earnings (loss) and adjusted funds from (used in) operations. Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.

Non-GAAP and Other Financial Measures

Certain financial measures in this MD&A – namely adjusted operating earnings (loss), adjusted funds from (used in) operations, metrics contained in return on capital employed (ROCE) and ROCE excluding impairments and impairment reversals, price realizations, Oil Sands operations cash operating costs, Fort Hills cash operating costs, Syncrude cash operating costs, refining and marketing margin, refining operating expense, free funds flow, discretionary free funds flow (deficit), net debt, total debt, and last-in, first-out (LIFO) inventory valuation methodology and related per share or per barrel amounts or metrics that contain such measures – are not prescribed by generally accepted accounting principles (GAAP). Adjusted operating earnings (loss), Oil Sands operations cash operating costs, Fort Hills cash operating costs, Syncrude cash operating costs and LIFO inventory valuation methodology are defined in the Advisories – Non-GAAP and Other Financial Measures section of this MD&A and reconciled to the most directly comparable GAAP measures in the Financial Information and Segment Results and Analysis sections of this MD&A. ROCE, ROCE excluding impairments and impairment reversals, price realizations, adjusted funds from (used in) operations, free funds flow, discretionary free funds flow (deficit), net debt, total debt, refining and marketing margin, and refining operating expense are defined and reconciled, where applicable, to the most directly comparable GAAP measures in the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

Beginning in the fourth quarter of 2021, the company changed the label of operating earnings (loss) and funds from (used in) operations to adjusted operating earnings (loss) and adjusted funds from (used in) operations, respectively, to better distinguish the non-GAAP financial measures from the comparable GAAP measures and better reflect the purpose of the measures. The composition of the measures remains unchanged and therefore no prior periods were revised.

Measurement Conversions

Crude oil and natural gas liquids volumes have been converted to mcfe on the basis of one bbl to six mcf in this MD&A. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Refer to the Advisories – Measurement Conversions section of this MD&A.

Table of Contents

Risks and Forward-Looking Information

The company's business, reserves, financial condition and results of operations may be affected by a number of factors, including, but not limited to, the factors described in the Risk Factors section of this MD&A.

This MD&A contains certain forward-looking statements and forward-looking information (collectively, forward-looking statements) within the meaning of applicable Canadian and U.S. securities laws and other information based on Suncor's current expectations, estimates, projections and assumptions. Forward-looking statements are subject to a number of risks and uncertainties, including those discussed in this MD&A and Suncor's other disclosure documents filed with Canadian securities regulatory authorities and the SEC, many of which are beyond the company's control. Readers are cautioned that actual results may differ materially from those expressed or implied by forward-looking statements contained herein. Refer to the Advisories – Forward-Looking Information section of this MD&A for information on the material risk factors and assumptions underlying the forward-looking statements contained herein.

1. Financial and Operating Summary

Financial Summary

Year ended December 31 ($ millions, except per share amounts)	2022	2021	2020
Gross revenues	**62 907**	41 133	24 900
Royalties	**(4 571)**	(2 001)	(238)
Operating revenues, net of royalties	**58 336**	39 132	24 662
Net earnings (loss)	**9 077**	4 119	(4 319)
per common share – basic (dollars)	**6.54**	2.77	(2.83)
per common share – diluted (dollars)	**6.53**	2.77	(2.83)
Adjusted operating earnings (loss) (1)(2)(3)	**11 566**	3 805	(2 213)
per common share(4)	**8.34**	2.56	(1.45)
Adjusted funds from operations(1)(2)	**18 101**	10 257	3 876
per common share(4)	**13.05**	6.89	2.54
Cash flow provided by operating activities	**15 680**	11 764	2 675
per common share(4)	**11.30**	7.91	1.75
Dividends paid on common shares	**2 596**	1 550	1 670
per common share(4)	**1.88**	1.05	1.10
Weighted average number of common shares in millions – basic	**1 387**	1 488	1 526
Weighted average number of common shares in millions – diluted	**1 390**	1 489	1 526
ROCE(1) (%)	**19.4**	8.6	(6.9)
ROCE excluding impairments and impairment reversals(1) (%)	**22.9**	8.2	(2.9)
Capital expenditures(5)(6)	**4 819**	4 411	3 806
Asset sustainment and maintenance	**3 315**	3 057	2 388
Economic investment	**1 504**	1 354	1 418
Free funds flow (deficit)(1)	**13 114**	5 702	(50)
Balance sheet (at December 31)			
Total assets	**84 618**	83 739	84 616
Net debt(1)	**13 639**	16 149	19 814
Total long-term liabilities(7)	**32 382**	36 726	38 310

(1) Non-GAAP financial measures or contains non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(2) Beginning in the fourth quarter of 2021, the company revised the label of operating earnings (loss) and funds from (used in) operations to adjusted operating earnings (loss) and adjusted funds from (used in) operations, respectively, to better distinguish the non-GAAP financial measures from the comparable GAAP measures and better reflect the purpose of the measures. The composition of the measures remains unchanged and therefore no prior periods were revised.
(3) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been revised to reflect this change.
(4) Represented on a basic per share basis.
(5) Excludes capitalized interest of $168 million in 2022, $144 million in 2021 and $120 million in 2020.
(6) Excludes capital expenditures related to assets held for sale of $133 million in 2022.
(7) Includes long-term debt, long-term lease liabilities, other long-term liabilities, provisions and deferred income taxes.

Table of Contents

Operating Summary

Year ended December 31	2022	2021	2020
Production volumes			
Oil Sands - Upgraded - net SCO and diesel (mbbls/d)	**480.0**	468.6	466.2
Oil Sands - Non-upgraded bitumen (mbbls/d)	**185.2**	175.6	127.2
Exploration and Production (mboe/d)	**78.0**	87.5	101.7
Total	**743.2**	731.7	695.1
Average price realizations[1][2] ($/boe)			
Upgraded – net SCO and diesel	**118.88**	77.73	43.83
Non-upgraded bitumen	**84.63**	53.80	22.37
Oil Sands crude sales basket (all products)	**109.57**	70.96	39.29
Exploration and Production Canada	**128.07**	84.70	49.69
Exploration and Production International[3]	**126.61**	82.16	50.28
Refinery crude oil processed (mbbls/d)	**433.2**	415.5	407.0
Refinery utilization[4] (%)			
Eastern North America	**93**	91	91
Western North America	**93**	87	86
Total	**93**	89	88
Refining and marketing gross margin - FIFO [1] ($/bbl)	**55.85**	36.85	25.30
Refining and marketing gross margin - LIFO [1] ($/bbl)	**54.45**	30.90	28.65

(1) Contains non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(2) Net of transportation costs, but before royalties.
(3) Exploration and Production International price realizations include the company's U.K. and Norway assets and exclude Libya for all periods presented.
(4) Refinery utilization is the amount of crude oil run through crude distillation units, expressed as a percentage of the nameplate capacity of these units. The Edmonton refinery crude processing capacity increased to 146,000 bbls/d in 2021 from 142,000 bbls/d in 2020.

Table of Contents

Segment Summary

Year ended December 31 ($ millions)	2022	2021	2020
Earnings (loss) before income taxes [1]			
Oil Sands	**5 633**	2 825	(5 238)
Exploration and Production	**3 221**	1 791	(1 089)
Refining and Marketing	**5 694**	2 867	1 167
Corporate and Eliminations	**(2 232)**	(1 913)	(937)
Income tax (expense) recovery	**(3 239)**	(1 451)	1 778
Net earnings (loss)	**9 077**	4 119	(4 319)
Adjusted operating earnings (loss) [1][2][3]			
Oil Sands	**9 042**	2 829	(3 214)
Exploration and Production	**2 494**	1 343	30
Refining and Marketing	**5 687**	2 857	1 189
Corporate and Eliminations	**(1 503)**	(1 778)	(1 249)
Income tax (expense) recovery included in adjusted operating earnings	**(4 154)**	(1 446)	1 031
Total	**11 566**	3 805	(2 213)
Adjusted funds from (used in) operations [1][2]			
Oil Sands	**13 831**	7 575	1 341
Exploration and Production	**3 178**	1 951	1 118
Refining and Marketing	**6 561**	3 831	2 033
Corporate and Eliminations	**(1 240)**	(1 705)	(1 275)
Current income tax (expense) recovery	**(4 229)**	(1 395)	659
Total	**18 101**	10 257	3 876
Change in non-cash working capital	**(2 421)**	1 507	(1 201)
Cash flow provided by operating activities	**15 680**	11 764	2 675

(1) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated net earnings (loss), adjusted operating earnings (loss) and adjusted funds from (used in) operations. Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.

(2) Non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

(3) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been revised to reflect this change.

Table of Contents

2. Suncor Overview

Suncor is an integrated energy company headquartered in Calgary, Alberta, Canada. Suncor's operations include oil sands development, production and upgrading; offshore oil and gas; petroleum refining in Canada and the U.S.; and the company's Petro-Canada™ retail and wholesale distribution networks (including Canada's Electric Highway™, a coast-to-coast network of fast-charging electric vehicle stations). Suncor is developing petroleum resources while advancing the transition to a low-emissions future through investments in power, renewable fuels and hydrogen. Suncor also conducts energy trading activities focused principally on marketing and trading crude oil, natural gas, byproducts, refined products and power. Suncor has been recognized for its performance and transparent reporting on the Dow Jones Sustainability World Index, FTSE4Good Index and CDP. Suncor's common shares (symbol: SU) are listed on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE).

For a description of Suncor's business segments, refer to the Segment Results and Analysis section of this MD&A.

Suncor's Strategy

Delivering competitive and sustainable returns to shareholders is a top priority of the company. We aim to maximize shareholder returns by focusing on safety above all else, operational excellence, capital discipline through pragmatic investments in high-value projects, and our commitment to environmental stewardship and sustainability. We believe that our commitment to capital discipline, our balance sheet strength and financial health provide the foundation for our capital allocation framework, supporting long-term value creation and increasing returns to shareholders. We believe that Suncor is well positioned to execute on its strategy and priorities due to the company's competitive advantages: a unique, physically integrated portfolio with scale and strength; our regional oil sands advantage, including an industry-leading long-life, low-decline oil sands reserves base; an offshore business that provides geographically diversified cash flow; a highly efficient, tightly integrated downstream business supported by competitive sales channels; and our investment in sustainability, technology and innovation.

Key components of Suncor's strategy include:

- **Optimize value through integration and secured market access** – From the ground to the gas station, Suncor optimizes profit along each step of the value chain, through the regional scale and strength of the company's Oil Sands assets and the integration of its upstream assets with its midstream and refining assets. Our scale, broad asset base and operational flexibility allow us to optimize the production of higher-value synthetic crude oil (SCO) in the upstream business, while our extensive logistics assets, marketing expertise and sales channels drive additional value as equity barrels move down the value chain. Through this midstream and marketing network, the company maximizes its crude production and refinery utilization by securing sales outlets and receiving global-based pricing for the majority of its production.

- **Optimize asset portfolio** – The company is focused on maximizing value through its core business. To enable greater fit and focus and optimize its portfolio around its core assets, driving additional value, the company is streamlining its asset portfolio. In 2022, the company completed the sale of its Exploration and Production (E&P) assets in Norway and subsequent to 2022, reached an agreement for the sale of its U.K. E&P portfolio, which is expected to close in mid-2023. Subsequent to 2022, the company also completed the sale of its wind and solar assets and completed the acquisition of additional working interest in the Fort Hills Project (Fort Hills), an asset that is core to Suncor's integrated model, increasing the company's and its affiliate's total aggregate working interest to 68.76%.

- **Drive value through high-return investments** – Suncor is focused on pursuing high-return projects and investments that are aligned with our core capabilities and are expected to create long-term value for the company . Suncor's significant long-life, low-decline reserves base, combined with our industry expertise, allows the company to execute margin improvement strategies, such as tailings technology advancements, incremental debottlenecking and progressing opportunities to further increase the integration and flexibility of our operations. The company also continues to progress technologies to help improve safety, productivity and reliability and investments to accelerate progress towards our net-zero greenhouse gas (GHG) emissions objective, such as the replacement of the coke-fired boilers at Oil Sands Base with a cogeneration facility.

- **Maximize value through operational excellence and reliability** – Suncor aims to get the most out of its assets through a focus on operational excellence, which means operating in a way that is safe, reliable, cost-efficient and environmentally responsible, while continuing to practise capital discipline. The company is focused on leveraging its

scale and integrated model to drive cost and capital efficiency and maximize margin capture. Looking ahead, the primary focus for cost management will be to continue efforts to sustainably reduce controllable operating costs by leveraging the company's regional scale and standardized processes to drive cost efficiency and reliability improvements, and leveraging its integrated operations to improve the scope, duration and sequencing of turnarounds.

- **Technology and people-enabled** – Suncor is focused on leveraging technologies to improve the safety, productivity, reliability and environmental performance of the company. We believe that the continuing implementation of digital technologies and analytics will facilitate the transition to the workplace of the future, bolster operational excellence, including improved safety performance, and drive additional value. Investments in new technologies that leverage Suncor's existing capabilities, and provide new sustainable energy sources, are also key to Suncor's net-zero GHG objective.

- **Continue to be an industry leader in sustainable development and the global energy expansion** – Suncor's integrated approach to sustainability includes leadership and industry collaboration in environmental performance, enhanced social responsibility, underpinned by our commitment to creating value for our stakeholders. Our objective is to be a net-zero GHG emissions company by 2050 and we have set ambitious near-term goals to reduce emissions across our value chain. We aim to reduce emissions across our base business, grow our low-emissions energy business and work with others to reduce industry emissions. Suncor plans to achieve these objectives by making pragmatic and economic investments that are synergistic with our core capabilities and assets, including investments in hydrogen and renewable fuels. In support of Suncor's ambition to be net-zero GHG emissions by 2050, the company works collaboratively with industry peers through the Pathways Alliance and also with federal and provincial governments.

2022 Highlights

In 2022, Suncor generated record adjusted funds from operations(1) of $18.1 billion, or $13.05 per common share, outperforming the previous annual per share record from 2019 by nearly 90%.

- In 2022, Suncor generated $18.101 billion in adjusted funds from operations, or $13.05 per common share, compared to $10.257 billion, or $6.89 per common share, in the prior year. Cash flow provided by operating activities, which includes changes in non-cash working capital, was $15.680 billion, or $11.30 per common share, in 2022, compared to $11.764 billion, or $7.91 per common share, in the prior year. The increased cash flows were a result of strong benchmark pricing in the upstream and strong benchmark crack spreads in the downstream, resulting in the company capturing significant value on both ends of its integrated model.
- Suncor generated record adjusted operating earnings(1) of $11.566 billion in 2022, or $8.34 per share, compared to $3.805 billion, or $2.56 per share, in the prior year. Net earnings were $9.077 billion in 2022, or $6.54 per common share, compared to $4.119 billion, or $2.77 per common share, in the prior year.
- The company achieved approximately $865 million of incremental free funds flow by the end of 2022 through the implementation of digital, process and technology initiatives.

Suncor delivered on its capital allocation framework in 2022, returning a record $7.7 billion to its shareholders, including two dividend increases during the year, while reducing net debt(1) by approximately $3.2 billion excluding the impacts of a $729 million unrealized foreign exchange loss on the revaluation of U.S. dollar denominated debt.

- In 2022, Suncor returned a total of approximately $7.7 billion of value to its shareholders, compared to approximately $3.9 billion in the prior year. Record shareholder returns in 2022 included approximately $2.6 billion of dividends paid and approximately $5.1 billion in share repurchases. In 2022, the company repurchased a record 116.9 million common shares at an average price of $43.92 per common share, or the equivalent of 8.1% of its issued and outstanding common shares as at December 31, 2021.
- Demonstrating management's confidence in the company's ability to generate sustainable and increasing cash flows, the company increased its dividend per share twice in 2022, most recently in the fourth quarter, to $0.52 per share, which represents a 23.8% increase over the fourth quarter of 2021 dividend and the highest quarterly dividend per share in the company's history.
- In 2022, the company reduced net debt by approximately $3.2 billion excluding the impacts of a $729 million unrealized foreign exchange loss on the revaluation of U.S. dollar denominated debt, representing a net debt reduction of over $2.5 billion. The significant debt reduction provides ongoing balance sheet flexibility, reduces long-term financing costs and demonstrates the company's commitment to reducing net debt.
- Subsequent to 2022, the Board approved a renewal of the company's normal course issuer bid (NCIB) for the repurchase of up to 10% of Suncor's public float as at February 3, 2023, over a twelve-month period, and concurrently, the TSX accepted a notice filed by Suncor to renew its NCIB in respect of the repurchase of such shares.

(1) Non-GAAP financial measure. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

In 2022, in alignment with Suncor's strategy to maximize value through its core business, Suncor streamlined its portfolio to enable greater fit and focus and drive long-term value for its shareholders.

- In 2022, the company completed the sale of its E&P assets in Norway for gross proceeds of approximately $430 million, before closing adjustments and other closing costs. Subsequent to 2022, the company reached an agreement for the sale of its U.K. E&P portfolio for gross proceeds of approximately $1.2 billion, including a contingent consideration of approximately $338 million, before closing adjustments and other closing costs. The sale is pending regulatory approval and is expected to close in mid-2023. Subsequent to 2022, the company also completed the sale of its wind and solar assets. These disciplined decisions enable the company to allocate resources to core assets and maximize shareholder returns.

- Subsequent to 2022, the company completed the acquisition of an additional 14.65% working interest in Fort Hills from Teck Resources Limited (Teck) for $688 million, before working capital and other closing adjustments, bringing the company's and its affiliate's total aggregate working interest in Fort Hills to 68.76%. The transaction meets Suncor's return objectives and builds upon the company's strategy to optimize its portfolio around its core assets and integrated model, while leveraging its regional oil sands advantage .

- In 2022, as a result of a comprehensive strategic review of its downstream retail business, Suncor announced that it will retain and continue to improve and optimize the Petro-Canada™ retail business.

Oil Sands delivered record annual adjusted funds from operations of $13.8 billion, and the second highest production in the company's history, including strong SCO production, as the company maximized value through leveraging the strength and flexibility of its integrated operations.

- In 2022, for the second consecutive year, Oil Sands delivered record annual adjusted funds from operations of $13.831 billion, compared to $7.575 billion in 2021, an increase of nearly 85%. Oil Sands adjusted operating earnings increased to $9.042 billion in 2022, compared to $2.829 billion in the prior year, and Oil Sands earnings before income taxes(1) increased to $5.633 billion in 2022, compared to $2.825 billion in the prior year.

- In 2022, Suncor delivered total Oil Sands production of 665,200 bbls/d, compared to 644,200 bbls/d in 2021. SCO production increased to 480,000 bbls/d in 2022, compared to 468,600 bbls/d in the prior year. SCO production in 2022 reflects the second highest in the company's history, driven by combined upgrader utilization of 89%, compared to 87% in the prior year. Syncrude delivered record mine bitumen production in 2022, with both strong SCO production and by capitalizing on the company's regional integration through transfers on the interconnecting pipelines between Oil Sands Base and Syncrude. Non-upgraded bitumen production increased to 185,200 bbls/d in 2022, compared to 175,600 bbls/d in the prior year, due to increased production from Fort Hills and strong performance from the company's In Situ assets.

The company strengthened its focus on its East Coast E&P assets, restarting development activities on the West White Rose Project, and progressing the Terra Nova Asset Life Extension Project, both of which are expected to deliver significant returns, cash flow and long-term value to shareholders.

- Driven by significantly higher realized crude prices in 2022, E&P adjusted funds from operations increased to $3.178 billion in the current year, compared to $1.951 billion in the prior year. E&P adjusted operating earnings increased to $2.494 billion in 2022, compared to $1.343 billion in the prior year, and E&P earnings before income taxes increased to $3.221 billion in 2022, compared to $1.791 billion in the prior year.

- In 2022, Suncor and the joint venture owners restarted the West White Rose Project, which is expected to extend the production life of the White Rose field, providing long-term value for the company. As a result of the restart decision, Suncor increased its ownership in the White Rose assets by an additional 12.5% to approximately 39%.

- At Terra Nova, investment in the Terra Nova Floating, Production, Storage and Offloading (FPSO) facility related to the Asset Life Extension (ALE) Project was substantially progressed in 2022, and the asset has returned to Canada, with a safe return to production expected in the second quarter of 2023.

(1) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated net earnings (loss), adjusted operating earnings (loss) and adjusted funds from (used in) operations. Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.

Suncor's Refining and Marketing (R&M) segment delivered record adjusted funds from operations in 2022, supported by its reliable and industry-leading refinery utilization rates and its secured sales channels.

- R&M delivered record adjusted funds from operations of $6.561 billion in 2022, compared to $3.831 billion in 2021, outperforming the last R&M annual record in 2018 by nearly 35%. In 2022, R&M generated $6.791 billion in adjusted funds from operations, excluding the impacts of a $230 million first-in, first-out (FIFO) gain,(1) compared to $4.803 billion in 2021, excluding the impacts of a $972 million FIFO gain. R&M adjusted operating earnings increased to $5.687 billion in 2022, compared to $2.857 billion in the prior year, and R&M earnings before income taxes increased to $5.694 billion in 2022, compared to $2.867 billion in the prior year.

- Suncor leveraged its refinery product mix, midstream logistics flexibility, strong domestic sales network including integration with its retail network, export capabilities and storage capacity to deliver refinery crude throughput of 433,200 bbls/d in 2022, and industry-leading utilization rates of 93%, compared to 415,500 bbls/d and 89% in the prior year. The company's Canadian refineries outperformed the Canadian refining utilization industry average by nearly 5%(2) during the year.

The company progressed its objective of being a net-zero GHG emissions company by 2050 and strengthened its focus on areas of energy expansion that are complementary to its base business and leverage its existing core capabilities.

- In 2022, the company reached an agreement for the sale of its wind and solar assets for gross proceeds of approximately $730 million, before closing adjustments and other closing costs. The sale was completed in the first quarter of 2023. The sale of its wind and solar assets was in support of the company's strategy to focus on areas of energy expansion that are more complementary to its base business, with an emphasis on hydrogen and renewable fuels, and ongoing strategic investments in low-carbon power.

- To help reach Suncor's strategic objective to be net-zero by 2050, the company has continued to work collaboratively with industry peers through the Pathways Alliance and with federal and provincial governments during 2022. Significant progress has been achieved to advance the Alliance's foundational carbon capture project and, subsequent to 2022, the Pathways Alliance was awarded exploratory rights from the Government of Alberta for the proposed carbon capture and storage hub to safely and permanently store CO_2 captured from over 20 oil sands facilities in northern Alberta.

(1) The estimated impact of the LIFO method is a non-GAAP financial measure. FIFO inventory valuation includes the impact of commodity risk management activities. See the Advisories – Non-GAAP and Other Financial Measures section of this document.

(2) Source: Canada Energy Regulator – https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/crude-oil-petroleum-products/statistics/weekly-crude-run-summary-data/index.html.

3. Financial Information

Net Earnings

Suncor's net earnings in 2022 were $9.077 billion, compared to $4.119 billion in 2021. Net earnings were impacted by the same factors that influenced adjusted operating earnings, which are described below. Other items affecting net earnings in 2022 and 2021 included:

- An unrealized foreign exchange loss on the revaluation of U.S. dollar denominated debt of $729 million recorded in financing expenses in 2022, compared to a gain of $113 million in 2021.
- In 2022, in connection with the company entering into a conditional agreement to acquire Teck's interest in Fort Hills, as well as updates to the Fort Hills long-range plan including production and operating cost plans, the company recorded a non-cash impairment of $3.397 billion against its share of the Fort Hills assets in the Oil Sands segment. Also in 2022, as a result of the decision to restart the West White Rose Project, the company recorded a non-cash impairment reversal of $715 million on its share of the White Rose assets in the E&P segment, and, as a result of the company's expected sale of its E&P assets in Norway, and the subsequently reached agreement for such sale, the company recorded a non-cash impairment of $70 million against its share of its assets in Norway.
- In 2022, the recognition of $147 million of property damage insurance proceeds recorded in other income related to the company's assets in Libya in the E&P segment.
- A $65 million foreign exchange loss in 2022 related to the sale of the company's share of its assets in Norway in the E&P segment.
- In 2021, the company recorded a non-cash impairment reversal of $221 million against its share of the Terra Nova assets, in the E&P segment, as a result of the decision to proceed with the Terra Nova ALE Project and the benefit of royalty and financial support from the Government of Newfoundland and Labrador.
- A gain of $227 million in 2021 on the sale of the company's interest in the Golden Eagle Area Development in the E&P segment.
- A restructuring charge of $168 million in 2021 related to workforce reductions, recorded in operating, selling and general expenses in the Corporate and Eliminations segment.
- A loss of $80 million in 2021 in connection with the early repayment of long-term debt, recorded in financing expenses in the Corporate and Eliminations segment.
- An income tax recovery excluded from adjusted operating earnings of $915 million in 2022, compared to an expense of $5 million in 2021.

Table of Contents

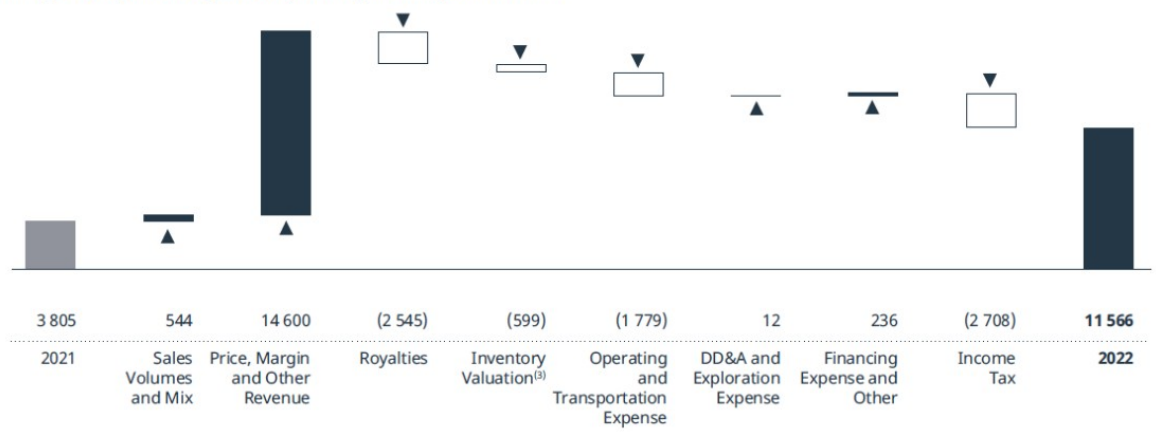
Adjusted Operating Earnings (Loss)

Consolidated Adjusted Operating Earnings (Loss) Reconciliation (1)(2)

Year ended December 31 ($ millions)	2022	2021	2020
Net earnings (loss)	**9 077**	4 119	(4 319)
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**729**	(113)	(312)
Unrealized loss (gain) on risk management activities (2)	**5**	(6)	39
Asset impairment (reversal) (3)	**2 752**	(221)	2 940
Recognition of insurance proceeds	**(147)**	—	—
Loss (gain) on significant disposal	**65**	(227)	—
Restructuring charge	**—**	168	—
Loss on early repayment of long-term debt	**—**	80	—
Provision for pipeline project (4)	**—**	—	186
Income tax (recovery) expense excluded from adjusted operating earnings (5)	**(915)**	5	(747)
Adjusted operating earnings (loss) (1)(2)	**11 566**	3 805	(2 213)

(1) Non-GAAP financial measure. All reconciling items are presented on a before-tax basis and adjusted for income taxes in the income tax (recovery) expense on adjusted operating earnings adjustments line. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(2) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been revised to reflect this change.
(3) In 2020, the company recorded non-cash impairment charges of $1.821 billion on its share of the Fort Hills assets, in the Oil Sands segment, and $1.119 billion against its share of the White Rose and Terra Nova assets, in the E&P segment, due to a decline in forecasted crude oil prices in 2020 as a result of decreased global demand due to the impacts of the COVID-19 pandemic, the high degree of uncertainty surrounding the future of the West White Rose Project and changes to their respective capital, operating and production plans.
(4) In 2020, the company recorded a provision to transportation expense for $186 million related to the Keystone XL pipeline project in the Oil Sands segment.
(5) In 2022, income tax (recovery) expense excluded from adjusted operating earnings includes a deferred income tax recovery of $171 million related to the anticipated sale of the company's U.K. E&P portfolio and a current income tax recovery of $39 million related to the sale of its wind and solar assets.

Bridge Analysis of Adjusted Operating Earnings ($ millions)(1)(2)



(1) For an explanation of the construction of this bridge analysis, see the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(2) All reconciling items are presented on a before-tax basis and adjusted for income taxes in the Income Tax bridge factor.
(3) The bridge factor for Inventory Valuation is comprised of changes in the FIFO inventory valuation and short-term commodity risk management activities reported in the R&M segment, and changes in the intersegment elimination of profit reported in the Corporate and Eliminations segment.

Suncor's consolidated adjusted operating earnings increased to $11.566 billion in 2022, compared to $3.805 billion in the prior year. The increase in adjusted operating earnings in 2022 was primarily due to significantly higher crude oil and refined production realizations compared to the prior year, reflecting the improved business environment, and higher overall crude production and refinery throughput. These factors were partially offset by an increase in income taxes associated with increased earnings, increased royalties associated with higher crude price realizations, and increased operating and transportation expenses. Adjusted operating earnings were also impacted by a smaller strengthening in benchmark pricing in 2022 compared to the prior year, resulting in a net unfavourable inventory valuation change of $742 million on crude feedstock costs.

Adjusted Funds from Operations and Cash Flow Provided by Operating Activities

Adjusted funds from operations for 2022 were $18.101 billion, compared to $10.257 billion in 2021, and were impacted by the same factors as adjusted operating earnings described above.

Cash flow provided by operating activities, which includes changes in non-cash working capital, was $15.680 billion in 2022, compared to $11.764 billion in 2021. In addition to the factors noted above, cash flow provided by operating activities was further impacted by a use of cash in working capital in the current year, compared to a source of cash in the prior year. The use of cash in 2022 was primarily due to an increase in accounts receivable and inventory balances related to the increase in commodity prices and crude oil price realizations in 2022, partially offset by an increase in accounts payable and accrued liabilities.

Results for 2021 Compared with 2020

Suncor's net earnings in 2021 were $4.119 billion, compared to a net loss of $4.319 billion in 2020. Net earnings (loss) were impacted by the same factors impacting adjusted operating earnings (loss) described below, as well as the net earnings adjustments impacting 2021 and 2020, which are described in detail above.

Suncor's consolidated adjusted operating earnings increased to $3.805 billion in 2021, compared to an adjusted operating loss of $2.213 billion in the prior year. In 2021, crude oil and refined production realizations increased significantly compared to the prior year, which was significantly impacted by the COVID-19 pandemic and an increase in OPEC+ crude supply. The improving business environment in 2021 also resulted in a net favourable inventory valuation change on crude feedstock costs. Adjusted operating earnings in 2021 were also favourably impacted by higher overall crude production and refinery throughput compared to the prior year.

These factors were partially offset by an increase in royalties, primarily associated with higher crude price realizations, and increased operating and transportation expenses. The prior year adjusted operating loss was negatively impacted by the significant decline in transportation fuel demand and a net inventory valuation loss, partially offset by cost reductions in response to the COVID-19 pandemic.

Adjusted funds from operations for 2021 were $10.257 billion, compared to $3.876 billion in 2020, and were impacted by the same factors as adjusted operating earnings (loss) described above.

Cash flow provided by operating activities, which includes changes in non-cash working capital, was $11.764 billion in 2021, compared to $2.675 billion in 2020, reflecting a source of cash in working capital in 2021, compared to a use of cash in 2020. The source of cash in 2021 was primarily due to a net increase in taxes payable related to the company's 2021 income tax expenses, payable in early 2022, receipt of the company's 2020 federal income tax refund and an increase in accounts payable and accrued liabilities, partially offset by an increase in accounts receivable related to an increase in crude oil price realizations during the year.

Table of Contents

Business Environment

Commodity prices, refining crack spreads and foreign exchange rates are important factors that affect the results of Suncor's operations.

Average for the year ended December 31	2022	2021	2020
WTI crude oil at Cushing (US$/bbl)	**94.25**	67.95	39.40
Dated Brent Crude (US$/bbl)	**101.20**	70.75	41.65
Dated Brent/Maya crude oil FOB price differential (US$/bbl)	**15.50**	6.85	6.35
MSW at Edmonton (Cdn$/bbl)	**120.10**	80.30	45.60
WCS at Hardisty (US$/bbl)	**75.95**	54.90	26.85
Light/heavy differential for WTI at Cushing less WCS at Hardisty (US$/bbl)	**(18.30)**	(13.05)	(12.55)
SYN-WTI differential (US$/bbl)	**4.45**	(1.65)	(3.15)
Condensate at Edmonton (US$/bbl)	**93.75**	68.25	37.15
Natural gas (Alberta spot) at AECO (Cdn$/GJ)	**5.10**	3.45	2.10
Alberta Power Pool Price (Cdn$/MWh)	**162.45**	101.95	46.70
New York Harbor 2-1-1 crack (1) (US$/bbl)	**47.00**	19.40	11.75
Chicago 2-1-1 crack (1) (US$/bbl)	**38.10**	17.75	8.05
Portland 2-1-1 crack (1) (US$/bbl)	**51.35**	23.15	14.05
Gulf Coast 2-1-1 crack (1) (US$/bbl)	**40.40**	18.00	9.90
U.S. Renewable Volume Obligation (US$/bbl)	**7.75**	6.80	2.50
Exchange rate (US$/Cdn$)	**0.77**	0.80	0.75
Exchange rate (end of period) (US$/Cdn$)	**0.74**	0.79	0.78

(1) 2-1-1 crack spreads are indicators of the refining margin generated by converting two barrels of WTI into one barrel of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

In 2022, crude oil and crack spread benchmarks significantly improved compared to the prior year and were impacted by increased demand in addition to supply uncertainty related to the ongoing geopolitical conflict. Commodity market volatility increased during 2022, due to economic concerns regarding rising interest rates, inflationary pressures and future economic growth.

Suncor's sweet SCO price realizations are influenced primarily by the price of WTI at Cushing and by the supply and demand for sweet SCO from Western Canada. Sweet SCO price realizations in 2022 reflected an increase in WTI at Cushing, which averaged US$94.25/bbl compared to US$67.95/bbl in the prior year, and also reflected favourable SYN-WTI differentials. Suncor also produces sour SCO, the price of which is influenced by various crude benchmarks, including, but not limited to, MSW at Edmonton and WCS at Hardisty. The price of sour SCO can also be affected by prices negotiated for spot sales. Prices for MSW at Edmonton increased to $120.10/bbl in 2022 compared to $80.30/bbl in 2021, and prices for WCS at Hardisty increased to US$75.95/bbl in 2022, from US$54.90/bbl in 2021.

Bitumen production that Suncor does not upgrade is blended with diluent or SCO to facilitate delivery through pipeline systems. Net bitumen price realizations are, therefore, influenced by both prices for Canadian heavy crude oil (WCS at Hardisty is a common reference), prices for diluent (Condensate at Edmonton) and SCO. Bitumen price realizations can also be affected by bitumen quality premiums and discounts, as well as spot sales, and the price differential between Hardisty, Alberta, and U.S. Gulf Coast benchmarks.

The company leverages the expertise of its marketing and logistics business to optimize midstream capacity to the U.S. Gulf Coast and this is reflected in bitumen and sour SCO price realizations. Bitumen prices were unfavourably impacted by the widening of heavy crude oil differentials in 2022 compared to 2021 but were higher on an absolute basis due to the increase in WTI prices.

Suncor's price realizations for production from E&P Canada and E&P International assets are influenced primarily by the price for Brent crude, which increased to US$101.20/bbl in 2022, compared to US$70.75/bbl in 2021.

Suncor's refining and marketing gross margins are primarily influenced by 2-1-1 benchmark crack spreads, which are industry indicators approximating the gross margin on a barrel of crude oil that is refined to produce gasoline and distillates. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel and do not necessarily reflect the margins at a specific refinery. Suncor's realized refining and marketing gross margins are influenced by actual crude oil feedstock costs, refinery configuration, product mix and realized market prices unique to Suncor's refining and marketing business. In addition, U.S. regulatory renewable blending obligations influence the benchmark cracks, which may increase their volatility, while the cost of regulatory compliance is not deducted in calculating the benchmark cracks.

Suncor has developed an indicative 5-2-2-1 index based on publicly available pricing data to more accurately reflect Suncor's realized refining and marketing gross margin. This custom index is a single value representing a notional five barrels of crude oil of varying grades refined to produce two barrels each of gasoline and distillate and one barrel of secondary product to approximate Suncor's unique set of refinery configurations; overall crude slate and product mix, location, quality and grade differentials, and the benefits of its marketing margins. The custom index is calculated by taking the product value of refined products less the crude value of refinery feedstock excluding the impact of FIFO inventory accounting methodology. The product value incorporates the New York Harbor 2-1-1 crack, Chicago 2-1-1 crack, WTI benchmarks and a seasonal factor. The seasonal factor applies an incremental US$6.50/bbl in the first and fourth quarters and US$5.00/bbl in the second and third quarters and reflects the location, quality and grade differentials for refined products sold in the company's core markets during the winter and summer months, respectively. The crude value incorporates the SYN, WCS and WTI benchmarks.

Crack spreads are based on current crude feedstock prices, whereas actual earnings are accounted for on a FIFO basis in accordance with IFRS where a delay exists between the time that feedstock is purchased to when it is processed and when products are sold to a third party. A FIFO loss normally reflects a declining price environment for crude oil and finished products, whereas FIFO gains reflect an increasing price environment for crude oil and finished products. The company's realized refining and marketing gross margins are also presented on a LIFO basis, which is consistent with how industry benchmarks and the Suncor 5-2-2-1 index are calculated and with how management evaluates performance.

In 2022, the New York Harbor 2-1-1 and Chicago 2-1-1 benchmark crack spreads increased compared to 2021 due to increased demand for transportation fuels and declining North American refined product inventory levels, and to compensate for increased costs associated with renewable blending regulatory obligations. The Suncor 5-2-2-1 index was US$45.30/bbl in 2022 compared to US$26.55/bbl in 2021, reflecting the significant increase in benchmark crack spreads.

The cost of natural gas used in Suncor's Oil Sands and Refining operations is primarily referenced to Alberta spot prices at AECO. The average AECO benchmark increased to $5.10/GJ in 2022, from $3.45/GJ in the prior year.

Excess electricity produced in Suncor's Oil Sands operations business is sold to the Alberta Electric System Operator, with the proceeds netted against the Oil Sands operations cash operating costs per barrel metric. The Alberta power pool price increased to an average of $162.45/MWh in 2022 from $101.95/MWh in the prior year.

The majority of Suncor's revenues from the sale of oil and natural gas commodities are based on prices that are determined by or referenced to U.S. dollar benchmark prices, while the majority of Suncor's expenditures are realized in Canadian dollars. A decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of commodities. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease revenues received from the sale of commodities. In 2022, the Canadian dollar weakened in relation to the U.S. dollar as the average exchange rate decreased to US$0.77 per one Canadian dollar from US$0.80 per one Canadian dollar in 2021. The decrease in the Canadian dollar relative to the U.S. dollar had a positive impact on price realizations for the company in 2022 when compared to 2021.

Conversely, some of Suncor's assets and liabilities, notably approximately 75% of the company's debt, are denominated in U.S. dollars and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. A decrease in the value of the Canadian dollar, relative to the U.S. dollar, from the previous balance sheet date increases the amount of Canadian dollars required to settle U.S. dollar denominated obligations, while an increase in the value of the Canadian dollar, relative to the U.S. dollar, decreases the amount of Canadian dollars required to settle U.S. dollar denominated obligations. As at December 31, 2022, the Canadian dollar weakened in relation to the U.S. dollar as the exchange rate at the end of the period decreased to US$0.74 per one Canadian dollar from US$0.79 per one Canadian dollar in the prior year. This rate decrease had a negative impact on the company's debt balances in 2022 when compared to the prior year.

Economic Sensitivities(1)(2)

The following table illustrates the estimated effects that changes in certain factors would have had on 2022 net earnings and adjusted funds from operations(3) if the listed changes had occurred.

(Estimated change, in $ millions)	Impact on 2022 Net Earnings	Impact on 2022 Adjusted Funds from Operations (3)
Crude oil +US$1.00/bbl	180	180
Natural gas +Cdn$1.00/GJ(4)	(160)	(160)
2-1-1 crack spreads +US$1.00/bbl	140	140
Foreign exchange +$0.01 US$/Cdn$ related to operating activities (5)	(200)	(200)
Foreign exchange on U.S. dollar denominated debt +$0.01 US$/Cdn$	140	—

(1) Each line item in this table shows the effects of a change in that variable only, with other variables being held consistent.
(2) Changes for a variable imply that all such similar variables are impacted, such that Suncor's average price realizations increase uniformly. For instance, "Crude oil +US$1.00/bbl" implies that price realizations influenced by WTI, Brent, SCO, WCS, par crude at Edmonton and condensate all increase by US$1.00/bbl.
(3) Non-GAAP financial measure. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(4) The company's exposure to natural gas costs is partially mitigated by increased revenue from power sales, which is not included in the above sensitivity.
(5) Excludes the foreign exchange impact on U.S. dollar denominated debt.

Table of Contents

4. Segment Results and Analysis

Suncor has classified its operations into the following segments:

Oil Sands

Suncor's Oil Sands segment, with assets located in the Athabasca oil sands of northeast Alberta, produces bitumen from mining and in situ operations. Bitumen is either upgraded into SCO for refinery feedstock and diesel fuel, or blended with diluent for refinery feedstock or direct sale to market through the company's midstream infrastructure and its marketing activities. The segment includes the marketing, supply, transportation and risk management of crude oil, natural gas, power and byproducts. The Oil Sands segment includes:

- **Oil Sands operations** refer to Suncor's owned and operated mining, extraction, upgrading, in situ and related logistics, blending 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. This infrastructure includes utilities, energy, reclamation and storage facilities, the interconnecting pipelines between Suncor's Oil Sands Base operations and Syncrude, and the new hot bitumen transfer piping that connects Fort Hills to Oil Sands Base. Oil Sands Base also includes mining development opportunities, including interests in Base Mine Extension (100%) and Audet (100%).
    - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, including central processing facilities, cogeneration units, product transportation infrastructure, diluent import capabilities, storage assets and a cooling and blending facility. In Situ also includes development opportunities that may support future in situ production, including interests in Meadow Creek (75%), Lewis (100%), OSLO (77.78%), Gregoire (100%), various interests in Chard (25% to 50%) and a non-operated interest in Kirby (10%). In Situ production is either upgraded by Oil Sands Base, or blended with diluent and marketed directly to customers.
- **Fort Hills** includes Suncor's interest in the Fort Hills mining and extraction operation, which the company operates, and the East Tank Farm Development, in which Suncor holds a 51% interest and operates. Subsequent to 2022, Suncor acquired an additional 14.65% working interest in Fort Hills from Teck, increasing the company's and its affiliate's total aggregate working interest to 68.76%.
- **Syncrude** refers to Suncor's 58.74% interest in the oil sands mining and upgrading operation, which the company operates.

Exploration and Production

Suncor's E&P segment consists of offshore operations off the east coast of Canada and in the U.K. North Sea, and onshore assets in Libya and Syria. This segment also includes the marketing and risk management of crude oil and natural gas.

- **E&P Canada** operations include Suncor's 48% working interest in Terra Nova, which Suncor operates. Production at Terra Nova has been shut in since the fourth quarter of 2019. Investment in the Terra Nova FPSO facility related to the ALE Project was substantially progressed in 2022, and the asset has returned to Canada, with a safe return to production expected in the second quarter of 2023. In the second quarter of 2022, Suncor and the joint venture owners announced the decision to restart the West White Rose Project. In connection with the decision to restart the West White Rose Project, Suncor increased its interest in the White Rose assets by 12.5% to 40% in the base project and 38.6% in the extensions. Production from the West White Rose Project is expected to commence in the first half of 2026. Suncor also holds non-operated interests in Hibernia (20% in the base project and 19.485% in the Hibernia Southern Extension Unit) and Hebron (21.034%). In addition, the company holds interests in several exploration licences and significant discovery licences offshore Newfoundland and Labrador.
- **E&P International** operations include Suncor's non-operated interests in Buzzard (29.89%) and the Rosebank future development project (40%), both of which are located in the U.K. sector of the North Sea. In 2022, Suncor announced its intention to divest its U.K. assets. Subsequent to 2022, the company reached an agreement for the sale of its U.K. E&P portfolio, which is expected to close in mid-2023. In the third quarter of 2022, Suncor completed the sale of its

assets in Norway, which included its 30% working interest in Oda and 17.5% working interest in the Fenja project. In addition, Suncor owns, pursuant to exploration and production sharing agreements (EPSAs), working interests in the exploration and development of oilfields in the Sirte Basin in Libya. The Libya assets continued to produce at reduced rates during 2022. The timing of a return to normal operations in Libya remains uncertain due to continued political unrest. Suncor also owns, pursuant to a production sharing contract, an interest in the Ebla gas development in Syria, which has been suspended indefinitely since 2011 due to political unrest in the country.

Refining and Marketing

Suncor's R&M segment consists of two primary operations: the Refining and Supply and Marketing operations discussed below, as well as the infrastructure supporting the marketing, supply and risk management of refined products, crude oil, natural gas, power and byproducts. This segment also includes the trading of crude oil, refined products, natural gas and power.

- **Refining and Supply** operations refine crude oil and intermediate feedstock into a wide range of petroleum and petrochemical products. Refining and Supply consists of:
    - **Eastern North America** operations include a 137 mbbls/d refinery located in Montreal, Quebec, and an 85 mbbls/d refinery located in Sarnia, Ontario.
    - **Western North America** operations include a 146 mbbls/d refinery located in Edmonton, Alberta, and 98 mbbls/d refinery in 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 throughout Canada and the U.S., and the St. Clair ethanol plant in Ontario.
- **Marketing** operations sell refined petroleum products to retail customers primarily through a combination of company-owned Petro-Canada™ locations, branded dealers in Canada and company-owned locations in the U.S. marketed under other international brands. This includes Canada's Electric Highway™, a coast-to-coast network of fast-charging electric vehicle stations. The company's marketing operations also sells refined petroleum products through a nationwide commercial road transportation network in Canada, and to other commercial and industrial customers, including other retail sellers, in Canada and the U.S.

Corporate and Eliminations

The Corporate and Eliminations segment includes activities not directly attributable to any other operating segment. This segment previously included renewable energy assets, which were sold in the first quarter of 2023.

- **Corporate** activities include stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, and investments in clean technology, such as Suncor's investment in Enerkem Inc., LanzaJet, Inc., Svante Inc., the Varennes Carbon Recycling facility, the Pathways Alliance, and the early-stage design and engineering for the proposed ATCO/Suncor hydrogen project.
- Intersegment revenues and expenses are removed from consolidated results in **Eliminations**. Intersegment activity includes the sale of product between the company's segments, primarily relating to crude refining feedstock sold from Oil Sands to R&M.

Oil Sands

2022 Highlights

- In 2022, for the second consecutive year, Oil Sands delivered record annual adjusted funds from operations of $13.831 billion, compared to $7.575 billion in 2021, an increase of nearly 85%. Oil Sands adjusted operating earnings increased to $9.042 billion in 2022, compared to $2.829 billion in the prior year, and Oil Sands earnings before income taxes increased to $5.633 billion in 2022, compared to $2.825 billion in the prior year.

- In 2022, Suncor delivered total Oil Sands production of 665,200 bbls/d, compared to 644,200 bbls/d in 2021. SCO production increased to 480,000 bbls/d in 2022, compared to 468,600 bbls/d in the prior year. SCO production in 2022 reflects the second highest in the company's history, driven by combined upgrader utilization of 89%, compared to 87% in the prior year. Syncrude delivered record mine bitumen production in 2022, with both strong SCO production and by capitalizing on the company's regional integration through transfers on the interconnecting pipelines between Oil Sands Base and Syncrude. Non-upgraded bitumen production increased to 185,200 bbls/d in 2022, compared to 175,600 bbls/d in the prior year, due to increased production from Fort Hills and strong performance from the company's In Situ assets.

- Subsequent to 2022, the company completed the acquisition of an additional 14.65% working interest in Fort Hills from Teck for $688 million, before working capital and other closing adjustments, bringing the company's and its affiliate's total aggregate working interest in Fort Hills to 68.76%. The transaction meets Suncor's return objectives and builds upon the company's strategy to optimize its portfolio around its core assets and integrated model, while leveraging its regional oil sands advantage.

Strategy and Investment Update

Suncor has developed a unique asset base within the Athabasca oil sands, holding one of the largest resource positions in the area, and has established a regional advantage of scale and physical integration that the company seeks to leverage to maximize the value of its production volumes. The Oil Sands regional advantage is strengthened by the company's marketing and trading expertise, including its midstream and logistics network, which secures market access, optimizes price realizations and limits the impacts of external market factors, including pipeline disruptions, lack of egress or outages at refining customers.

Looking ahead, the company intends to continue to leverage its regional advantage by coordinating maintenance across its assets, leveraging economies of scale and utilizing the connectivity of its assets. In 2022, the company completed and commissioned the PFT hot bitumen transfer piping which enables transfers of up to 60,000 bbls/d of PFT from Fort Hills to upgrading at Oil Sands Base. This transfer piping, along with the interconnecting pipelines between Oil Sands Base and Syncrude, provide increased flexibility and optionality, supporting the company's ability to maximize the value of its barrels as well as minimize the impacts of maintenance or other internal and external market factors. The company continues to progress opportunities to further increase the connectivity and flexibility of its regional assets.

2022 was the company's first year of utilizing a new regional services central turnaround team to standardize turnaround execution and delivery, drive continuous improvement, and focus on reducing planned downtime in the years ahead. Looking forward, the company intends to leverage its regional scale and standardized services to drive cost efficiency and reliability improvements while leveraging its integrated operations to improve the scope, duration and sequencing of turnarounds.

The company is committed to delivering safe, reliable, low-cost production, while moving forward in the areas of technology innovation and environmental sustainability. Suncor is laser focused on driving improved safety performance across the company, specifically in its mine, tailings and drilling operations, as well as driving improved operational performance at its Oil Sands assets. The company is focused on the execution of clear and accelerated plans to improve safety, including leveraging human organizational performance principles, strengthening its risk management and systems, improving contractor safety management, engaging the frontline to deliver safe work with a strong safety culture, and implementing technologies that will help improve safety. In 2023, the company is progressing the implementation of technologies to help improve its safety performance, including collision awareness technology and a fatigue management solution, which are both aimed at preventing mobile equipment contact. Suncor will be the first oil sands operator to execute a full-scale implementation of these technologies, and the company is on track to complete go live by the end of 2023.

During the fourth quarter of 2022, the company entered into an agreement to acquire Teck's 21.3% interest in Fort Hills and its associated sales and logistics agreements for $1.0 billion, subject to working capital and other closing adjustments. Subsequent to the fourth quarter of 2022, TotalEnergies EP Canada Ltd. provided notice of the exercise of its contractual right of first refusal to acquire from Teck a 6.65% interest in Fort Hills, which reduced the amount of working interest available for Suncor to purchase. As a result, on February 2, 2023, Suncor completed the acquisition of an additional 14.65% working interest in Fort Hills for $688 million, before working capital and other closing adjustments, bringing the company's and its affiliate's total aggregate working interest in Fort Hills to 68.76%. The transaction meets Suncor's return objectives, providing long-term value for the company by adding approximately 28,000 bbls/d of bitumen production capacity, and builds upon the company's strategy to optimize its portfolio around its core assets.

In 2023, the company intends to continue progressing its three-year mine improvement plan at Fort Hills, which includes an accelerated sequence of mine development relative to its historical plans. Short-term production and operating cost impacts are expected in 2023 as the company develops the Centre and North pits while building adequate ore inventory.

2022 was Suncor's first full year as operator of the Syncrude asset, and the company achieved the realization of $300 million of annual gross synergies for the joint venture owners through workforce efficiencies and regional optimization.

The primary focus for cost management in 2023 will be to continue efforts to sustainably reduce controllable operating costs to offset inflationary pressures, as well as structural mine factors that are anticipated to increase near-term operating costs.

Capital allocation continues to focus on asset sustainment and maintenance projects designed to maintain safe and reliable operations, as well as advancing high-value economic investment projects. In 2023, construction will continue on the cogeneration facility to replace the coke-fired boilers at Oil Sands Base, which is expected to be in service in late 2024 and provide steam generation required for extraction and upgrading activities, at a lower cost and with significantly lower carbon emissions. The cogeneration facility is also expected to generate electricity that will be transmitted to Alberta's power grid, lowering the carbon intensity of the grid. Additional economic spend in 2023 is expected to include the Mildred Lake West Extension (MLX-W) project at Syncrude, which is expected to come online in late 2025, the Upgrader 1 coke drum replacement project, which is expected to be in service in late 2025, and the continued development of reserves at In Situ through the design and build of new well pads that will support capital efficiency. The MLX-W project is expected to sustain Syncrude's current production levels by extending the life of the North Mine using existing extraction and upgrading facilities while minimizing the environmental impacts of building new infrastructure.

Suncor will continue to seek opportunities for incremental debottlenecks to maximize the value of its In Situ assets. Debottlenecking capacity and timing will depend on economic conditions and can be supported by integrated well pad development and solvent steam-assisted gravity drainage technologies.

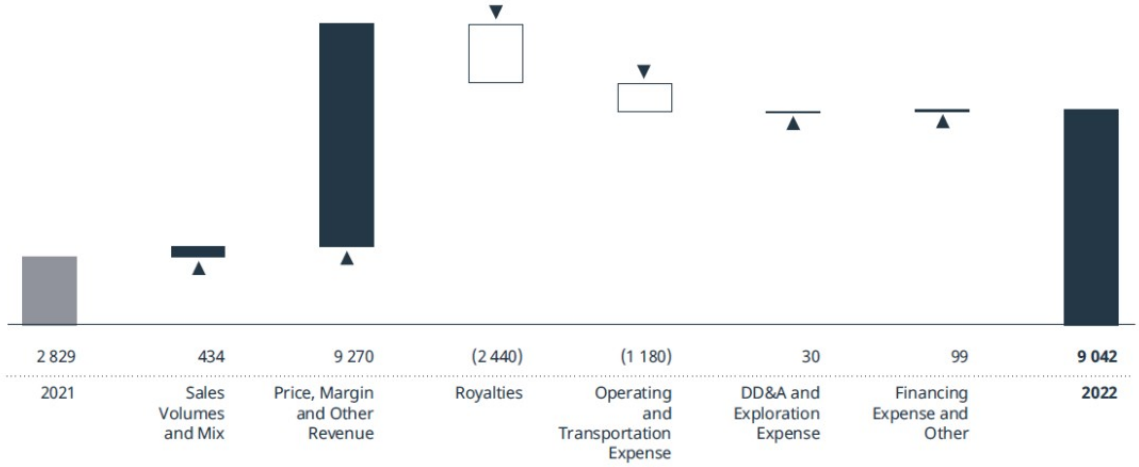
Table of Contents

Financial Highlights

Year ended December 31 ($ millions)	2022	2021	2020
Gross revenues	**30 431**	19 920	10 617
Less: Royalties	**(3 963)**	(1 523)	(95)
Operating revenues, net of royalties	**26 468**	18 397	10 522
Earnings (loss) before income taxes (1)	**5 633**	2 825	(5 238)
Adjusted for:			
Unrealized loss on risk management activities (2)	**12**	4	17
Asset impairment (3)	**3 397**	—	1 821
Provision for pipeline project (4)	**—**	—	186
Adjusted operating earnings (loss) (1)(5)	**9 042**	2 829	(3 214)
Adjusted funds from operations (1)(5)	**13 831**	7 575	1 341

(1) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated net earnings (loss), adjusted operating earnings (loss) and adjusted funds from (used in) operations. Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.
(2) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been revised to reflect this change.
(3) In 2020, the company recorded a non-cash impairment charge of $1.821 billion on its share of the Fort Hills assets due to a decline in forecasted heavy crude oil prices in 2020 as a result of decreased global demand due to the impacts of the COVID-19 pandemic and changes to its capital, operating and production plans.
(4) In 2020, the company recorded a provision to transportation expense for $186 million related to the Keystone XL pipeline project.
(5) Non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

Bridge Analysis of Adjusted Operating (Loss) Earnings ($ millions)(1)(2)



(1) For an explanation of the construction of this bridge analysis, see the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(2) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated adjusted operating earnings (loss). Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.

The Oil Sands segment had adjusted operating earnings of $9.042 billion in 2022, compared to $2.829 billion in 2021. The increase was primarily due to significantly higher realized crude oil prices and increased production, partially offset by higher royalties associated with higher crude price realizations and increased operating and transportation expenses.

Oil Sands earnings before income taxes were $5.633 billion in 2022, compared to $2.825 billion in 2021. In addition to the factors impacting adjusted operating earnings described above, earnings before income taxes for 2022 included a $12 million unrealized loss on risk management activities, compared to a loss of $4 million in 2021. 2022 earnings before income taxes also included a non-cash impairment charge of $3.397 billion against the company's share of the Fort Hills assets, in

connection with the company entering into a conditional agreement to acquire Teck's interest in Fort Hills, as well as updates to the Fort Hills long-range plan including production and operating cost plans.

Adjusted funds from operations for the Oil Sands segment were $13.831 billion in 2022, compared to $7.575 billion in 2021, and were influenced by the same factors that impacted adjusted operating earnings noted above.

Production Volumes(1)

Year ended December 31 (mbbls/d)	2022	2021	2020
Total Oil Sands bitumen production	**790.5**	770.3	710.4
SCO and diesel production(2)	**493.7**	483.5	477.5
Internally consumed diesel and internal transfers(3)(4)	**(13.7)**	(14.9)	(11.3)
Upgraded production – net SCO and diesel	**480.0**	468.6	466.2
Bitumen production	**191.9**	178.8	127.2
Internal bitumen transfers(4)(5)	**(6.7)**	(3.2)	—
Non-upgraded bitumen production	**185.2**	175.6	127.2
Total Oil Sands production	**665.2**	644.2	593.4

(1) Bitumen from Oil Sands Base operations is upgraded, while bitumen production from In Situ operations is either upgraded or sold directly to customers, including Suncor's own refineries, with SCO and diesel yields of approximately 79% of bitumen feedstock input. Fort Hills bitumen is either sold directly to customers as finished bitumen, including Suncor's own refineries, or to Oil Sands Base for upgrading. The majority of the bitumen produced at Syncrude is upgraded to sweet SCO and a small amount of diesel, at an approximate yield of 85%.

(2) Combined upgrader utilization rates are calculated using total upgraded production, inclusive of internally consumed diesel and internal transfers.

(3) Both Oil Sands operations and Syncrude produce diesel, which is internally consumed in mining operations, and Fort Hills and Syncrude use internally produced diesel from Oil Sands Base within their mining operations. In 2022, Oil Sands operations production volumes included 10,100 bbls/d of internally consumed diesel, of which 6,500 bbls/d was consumed at Oil Sands Base, 2,000 bbls/d was consumed at Fort Hills and 1,600 bbls/d was consumed at Syncrude. Syncrude production volumes included 2,000 bbls/d of internally consumed diesel.

(4) Internal feedstock transfers between Oil Sands operations and Syncrude through the interconnecting pipelines are included in gross SCO and bitumen production volumes. In 2022, Oil Sands operations included 1,400 bbls/d of SCO and 700 bbls/d of bitumen that was transferred to Suncor's share of Syncrude through the interconnecting pipelines. Syncrude production included 200 bbls/d of SCO and 5,700 bbls/d of bitumen that was transferred to Oil Sands Base through the interconnecting pipelines.

(5) Internal feedstock transfers from Fort Hills to Oil Sands operations through the PFT hot bitumen transfer piping are included in gross bitumen production volumes. In 2022, Fort Hills production included 300 bbls/d of bitumen that was transferred to Oil Sands Base.

The company's net SCO production was 480,000 bbls/d in 2022 compared to 468,600 bbls/d in 2021, marking the second-best year of SCO production in the company's history. During 2022, the company achieved a combined upgrader utilization rate of 89% compared to 87% in the prior year. Increased SCO production in 2022 was supported by record mine bitumen production at Syncrude, with both strong SCO production and by capitalizing on the company's regional integration through transfers on the interconnecting pipelines between Oil Sands Base and Syncrude.

Non-upgraded bitumen production increased to 185,200 bbls/d in 2022 from 175,600 bbls/d in the prior year, due to increased production from Fort Hills, which was partially offset by decreased saleable bitumen production from the company's In Situ assets, as a higher proportion of In Situ production was diverted to upgrading to maximize higher-value SCO production.

Table of Contents

Sales Volumes and Mix

Year ended December 31 (mbbls/d)	2022	2021	2020
Upgraded – net SCO and diesel	**482.6**	465.7	467.9
Non-upgraded bitumen	**180.7**	183.8	125.6
Total	**663.3**	649.5	593.5

SCO and diesel sales volumes increased to 482,600 bbls/d in 2022, compared to 465,700 bbls/d in 2021, consistent with the increase in production, and reflecting a draw of inventory in 2022, compared to a build in the prior year.

Non-upgraded bitumen sales volumes were 180,700 bbls/d in 2022, compared to 183,800 bbls/d in the prior year, reflecting a build of inventory in 2022, compared to a draw in the prior year, partially offset by the increase in production in the current year.

Price Realizations(1)

Year ended December 31 Net of transportation costs, but before royalties ($/bbl)	2022	2021	2020
Upgraded – net SCO and diesel	**118.88**	77.73	43.83
Non-upgraded bitumen	**84.63**	53.80	22.37
Crude sales basket (all products)	**109.57**	70.96	39.29
Crude sales basket, relative to WTI	**(13.02)**	(14.20)	(13.51)

(1) Contains non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

Oil Sands price realizations increased in 2022 compared to 2021, in line with the significantly higher commodity price environment and reflecting the margin enhancement opportunities driven by the company's sales and marketing organization.

Royalties

Royalties for the Oil Sands segment were higher in 2022 compared to 2021, primarily due to higher crude price realizations and increased sales volumes.

Expenses and Other Factors

Total Oil Sands operating and transportation expenses for 2022 were higher relative to 2021, as described in detail below. See the Cash Operating Costs section below for further details regarding cash operating costs and a breakdown of non-production costs by asset.

At Oil Sands operations, operating costs in 2022 increased compared to the prior year, primarily due to higher natural gas and other commodity prices, and increased maintenance costs.

At Fort Hills, operating costs in 2022 increased when compared to the prior year, primarily due to increased mining activity and higher production levels. Operating costs during 2022 were also impacted by higher natural gas and other commodity prices compared to the prior year.

At Syncrude, operating costs in 2022 increased compared to the prior year, primarily due to higher production levels, increased natural gas and other commodity prices, and increased maintenance costs.

In 2022, increased natural gas prices resulted in an increase of Oil Sands segment operating costs by approximately $370 million compared to 2021.

Table of Contents

Cash Operating Costs

Year ended December 31	2022	2021	2020
Oil Sands operating, selling and general expense (OS&G) (1)	**9 152**	8 056	7 169
Oil Sands operations cash operating costs (2) reconciliation			
Oil Sands operations OS&G	**5 429**	4 840	4 349
Non-production costs (3)	**(302)**	(317)	(167)
Excess power capacity and other (4)	**(586)**	(366)	(248)
Oil Sands operations cash operating costs (2) ($ millions)	**4 541**	4 157	3 934
Oil Sands operations production volumes (mbbls/d)	**415.7**	439.2	380.9
Oil Sands operations cash operating costs (2) ($/bbl)	**29.95**	25.90	28.20
Fort Hills cash operating costs (2) reconciliation			
Fort Hills OS&G	**1 146**	882	749
Non-production costs (3)	**(214)**	(118)	(51)
Fort Hills cash operating costs (2) ($ millions)	**932**	764	698
Fort Hills production volumes (mbbls/d)	**85.1**	50.7	58.1
Fort Hills cash operating costs (2) ($/bbl)	**30.00**	41.35	32.80
Syncrude cash operating costs (2) reconciliation			
Syncrude OS&G	**2 840**	2 449	2 116
Non-production costs (3)	**(368)**	(234)	(66)
Syncrude cash operating costs (2) ($ millions)	**2 472**	2 215	2 050
Syncrude production volumes (mbbls/d)	**184.8**	172.4	165.7
Syncrude cash operating costs (2) ($/bbl)	**36.65**	35.20	33.80

(1) Beginning in 2022, the company revised the presentation of its cash operating costs reconciliation to present Oil Sands inventory changes and internal transfers on an aggregate basis. Oil Sands inventory changes and internal transfers reflect: i) the impacts of changes in inventory levels and valuations, such that the company is able to present cost information based on production volumes; and ii) adjustments for internal diesel sales between assets. Comparative periods have been updated to reflect this change, with no impact to total Oil Sands operations, Fort Hills or Syncrude cash operating costs or cash operating costs per barrel. In 2022, Oil Sands OS&G includes ($263) million of inventory changes and internal transfers. In 2021, Oil Sands OS&G includes ($115) million of inventory changes and internal transfers. In 2020, OS&G includes ($45) million of inventory changes and internal transfers.

(2) Non-GAAP financial measures. Related per barrel amounts contain non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

(3) Significant non-production costs include, but are not limited to, share-based compensation adjustments, research costs, project startup costs and adjustments to reflect the cost of internal transfers in the receiving asset at the cost of production. In addition, non-production costs include safe-mode costs associated with the deferral of capital projects and additional costs incurred in response to the COVID-19 pandemic. Non-production costs in 2020 also include the relief provided under the CEWS program. Non-production costs at Fort Hills and Syncrude also include, but are not limited to, excess power revenue from cogeneration units and an adjustment to reflect internally produced diesel from Oil Sands operations at the cost of production.

(4) Oil Sands operations excess power capacity and other includes, but is not limited to, the operational revenue impacts of excess power from cogeneration units and the natural gas expense recorded as part of a non-monetary arrangement involving a third-party processor.

Oil Sands operations cash operating costs per barrel (1) in 2022 were $29.95, compared to $25.90 in 2021, due to higher operating, selling and general expenses, as detailed above, and decreased production. Excess power capacity and other costs at Oil Sands operations for 2022 were higher than the prior year, due mainly to an increase in excess power revenues resulting from significantly higher power prices, and an increase in non-monetary natural gas costs.

Fort Hills cash operating costs per barrel (1) decreased to $30.00 in 2022, compared to $41.35 in 2021, reflecting higher production, partially offset by higher operating, selling and general expenses, as detailed above. Fort Hills non-production costs were higher in 2022 compared to the prior year, primarily due to the increased price for internally sourced diesel, which is adjusted to reflect internally produced diesel from Oil Sands operations at the cost of production, and an increase in excess power revenues resulting from higher power prices.

Syncrude cash operating costs per barrel (1) averaged $36.65 in 2022, compared to $35.20 in 2021, due to an increase in operating, selling and general expenses, as detailed above, partially offset by higher production volumes. Non-production costs were higher in 2022 compared to 2021, primarily due to the increased price for internally sourced diesel, which is adjusted to reflect internally produced diesel from Oil Sands operations at the cost of production.

(1) Contains non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

Non-Cash Asset Impairment

During the third quarter of 2022, in connection with the company entering into a conditional agreement to acquire Teck's interest in Fort Hills, as well as updates to the Fort Hills long-range plan including production and operating cost plans, the company recorded a non-cash impairment of $3.397 billion against its share of the Fort Hills assets.

Planned Maintenance

Planned turnaround activities at Syncrude are scheduled for the second and fourth quarters of 2023. Significant planned turnaround activities at Oil Sands Base Upgrader 2 are scheduled to commence in the third quarter of 2023 and are expected to be completed in the fourth quarter. At Fort Hills, the first full plant turnaround is scheduled for the third quarter of 2023. The anticipated impact of these maintenance events has been reflected in the company's 2023 guidance.

Exploration and Production

2022 Highlights

- Driven by significantly higher realized crude prices in 2022, E&P adjusted funds from operations increased to $3.178 billion in the current year, compared to $1.951 billion in the prior year. E&P adjusted operating earnings increased to $2.494 billion in 2022, compared to $1.343 billion in the prior year, and E&P earnings before income taxes increased to $3.221 billion in 2022, compared to $1.791 billion in the prior year.
- In 2022, Suncor and the joint venture owners restarted the West White Rose Project, which is expected to extend the production life of the White Rose field, providing long-term value for the company. As a result of the restart decision, Suncor increased its ownership in the White Rose assets by an additional 12.5% to approximately 39%.
- At Terra Nova, investment in the Terra Nova FPSO facility related to the ALE Project was substantially progressed in 2022, and the asset has returned to Canada, with a safe return to production expected in the second quarter of 2023.
- In 2022, the company completed the sale of its E&P assets in Norway for gross proceeds of approximately $430 million, before closing adjustments and other closing costs. Subsequent to 2022, the company reached an agreement for the sale of its U.K. E&P portfolio for gross proceeds of approximately $1.2 billion, including a contingent consideration of approximately $338 million, before closing adjustments and other closing costs. The sale is pending regulatory approval and is expected to close in mid-2023. The disciplined decisions to adjust and streamline the company's E&P portfolio reinforce Suncor's continued focus on capital discipline and helps enable the company to allocate resources to core assets and maximize shareholder returns.

Strategy and Investment Update

The E&P segment delivers geographically diversified cash flows and focuses on low-cost projects that deliver significant returns and generate consistent free funds flow for the company. The E&P business leverages the company's marketing and trading expertise, which secures market access, optimizes price realizations, manages inventory levels and limits the impacts of external market factors.

Following the company increasing its working interest in Terra Nova in 2021 and White Rose in 2022, Suncor made disciplined decisions to adjust and streamline its E&P portfolio to increase its focus on its core business, completing the sale of its assets in Norway, and subsequent to 2022, reaching an agreement for the sale of its U.K. E&P portfolio for gross proceeds of approximately $1.2 billion, including a contingent consideration of approximately $338 million, before closing adjustments and other closing costs. The sale is pending regulatory approval and is expected to close in mid-2023.

Looking forward, the company continues to focus on strategic production growth of its East Coast E&P assets, with ongoing development activities intended to leverage existing facilities and infrastructure to provide incremental production and extend the productive life of existing fields, including development drilling at Hebron and Hibernia.

At Terra Nova, a safe return to production is expected in the second quarter of 2023. The Terra Nova ALE Project, which is expected to extend the production life of the Terra Nova field by approximately 10 years, is expected to provide significant returns to Suncor and many benefits to the Newfoundland and Labrador and Canadian economies in the form of taxes, royalties and employment.

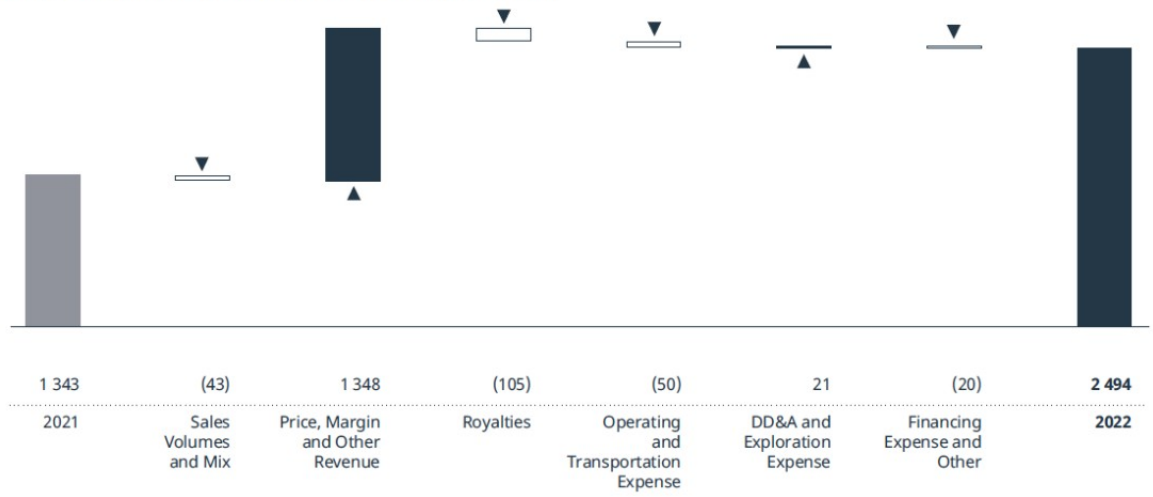
In 2023, the company intends to continue investment in the West White Rose Project. The West White Rose Project is expected to provide long-term value for the company by extending the production life of the White Rose field. Production from the West White Rose Project is expected to commence in the first half of 2026.

Financial Highlights

Year ended December 31 ($ millions)	2022	2021	2020
Gross revenues[1]	**4 331**	2 978	1 899
Less: Royalties[1]	**(608)**	(478)	(143)
Operating revenues, net of royalties	**3 723**	2 500	1 756
Earnings (loss) before income taxes[2]	**3 221**	1 791	(1 089)
Adjusted for:			
Asset (reversal) impairment[3]	**(645)**	(221)	1 119
Loss (gain) on significant disposals	**65**	(227)	—
Recognition of insurance proceeds	**(147)**	—	—
Adjusted operating earnings[2][4]	**2 494**	1 343	30
Adjusted funds from operations[2][4]	**3 178**	1 951	1 118

(1) Production from the company's Libya operations has been presented in the E&P section of this MD&A on an economic basis. Revenue and royalties from the company's Libya operations are presented under the working-interest basis, which is required for presentation purposes in the company's financial statements. In 2022, revenue includes a gross-up amount of $486 million, with an offsetting amount of $266 million in royalties in the E&P segment and $220 million in income tax expense recorded at the consolidated level. In 2021, revenue includes a gross-up amount of $345 million, with an offsetting amount of $241 million in royalties in the E&P segment and $104 million in income tax expense recorded at the consolidated level.
(2) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated net earnings (loss), adjusted operating earnings (loss) and adjusted funds from (used in) operations. Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.
(3) In 2020, the company recorded non-cash impairment charges of $1.119 billion against its share of the White Rose and Terra Nova assets due to a decline in forecasted crude oil prices in 2020 as a result of decreased global demand due to the impacts of the COVID-19 pandemic, the high degree of uncertainty surrounding the future of the West White Rose Project and changes to their respective capital, operating and production plans.
(4) Non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

Bridge Analysis of Adjusted Operating Earnings ($ millions)[1][2]



(1) For an explanation of the construction of this bridge analysis, see the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(2) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated adjusted operating earnings (loss). Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.

Adjusted operating earnings were $2.494 billion for E&P in 2022, compared to $1.343 billion in the prior year, with the increase due to significantly higher realized crude prices, partially offset by increased royalties associated with higher price realizations.

Earnings before income taxes for E&P were $3.221 billion in 2022, compared to $1.791 billion in 2021. In addition to the factors impacting adjusted operating earnings described above, earnings before income taxes in 2022 included a non-cash impairment reversal of $715 million on the company's share of the White Rose assets, a non-cash impairment of $70 million against the company's share of its assets in Norway, the recognition of $147 million of property damage insurance proceeds

related to the company's assets in Libya and a $65 million foreign exchange loss related to the sale of the company's share of its assets in Norway. Earnings before income taxes in 2021 included a non-cash impairment reversal of $221 million against the company's share of the Terra Nova assets and a gain of $227 million on the sale of the company's interest in the Golden Eagle Area Development.

Adjusted funds from operations were $3.178 billion in 2022, compared to $1.951 billion in 2021, and were influenced by the same factors that impacted adjusted operating earnings noted above.

Volumes

Year ended December 31	2022	2021	2020
E&P Canada (mbbls/d)	**50.2**	54.4	59.7
E&P International (mboe/d)	**27.8**	33.1	42.0
Total production (mboe/d)	**78.0**	87.5	101.7
Total sales volumes (mboe/d)	**80.6**	82.8	102.6

E&P Canada production volumes averaged 50,200 bbls/d in 2022, compared to 54,400 bbls/d the prior year, with the decrease primarily due to natural declines.

E&P International production volumes averaged 27,800 boe/d in 2022, compared to 33,100 boe/d in 2021, with the decrease primarily due to the absence of production from the Golden Eagle Area Development, as the sale of the company's working interest in the asset was completed in the fourth quarter of 2021.

E&P sales volumes averaged 80,600 boe/d in 2022, compared to 82,800 boe/d in the prior year, consistent with the decrease in production, partially offset by a draw of inventory in 2022, compared to a build in the prior year.

Price Realizations(1)

Year ended December 31 Net of transportation costs, but before royalties	2022	2021	2020
E&P Canada ($/bbl)	**128.07**	84.70	49.69
E&P International(2) ($/boe)	**126.61**	82.16	50.28

(1) Contains non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(2) E&P International price realizations include the company's U.K. and Norway assets and exclude Libya for all periods presented.

Price realizations at E&P Canada and E&P International increased in 2022 from the prior year, in line with the significantly higher commodity price environment.

Royalties

E&P royalties in 2022 were higher than the prior year primarily due to the increase in price realizations.

Expenses and Other Factors

Operating and transportation expenses for 2022 were higher compared to the prior year primarily due to increased costs at E&P Canada related to an increase in the company's working interest in White Rose and the Terra Nova ALE Project, and increased maintenance. The increase was partially offset by a higher one-time transportation provision recorded in the prior year compared to 2022, and by the sale of the Golden Eagle Area Development resulting in lower transportation and operating costs in the current year.

Non-Cash Asset Impairment Reversal and Impairment

During the second quarter of 2022, as a result of the decision to restart the West White Rose Project, the company recorded a non-cash impairment reversal of $715 million before-tax on its share of the White Rose assets. Also, during the second quarter of 2022, as a result of the company's expected sale of its assets in Norway, and the subsequently reached agreement for such sale, the company recorded a non-cash impairment of $70 million before-tax against its share of the Norway assets.

During the third quarter of 2021, the company recorded a non-cash impairment reversal of $221 million before-tax on its share of the Terra Nova assets as a result of the ALE Project moving forward and the benefit of royalty and financial support from the Government of Newfoundland and Labrador.

Planned Maintenance of Operated Assets

There are no planned maintenance activities scheduled for Suncor's operated assets in 2023.

Refining and Marketing

2022 Highlights

- R&M delivered record adjusted funds from operations of $6.561 billion in 2022, compared to $3.831 billion in 2021, outperforming the last R&M annual record in 2018 by nearly 35%. In 2022, R&M generated $6.791 billion in adjusted funds from operations, excluding the impacts of a $230 million FIFO gain,(1) compared to $4.803 billion in 2021, excluding the impacts of a $972 million FIFO gain. R&M adjusted operating earnings increased to $5.687 billion in 2022, compared to $2.857 billion in the prior year, and R&M earnings before income taxes increased to $5.694 billion in 2022, compared to $2.867 billion in the prior year.
- Suncor leveraged its refinery product mix, midstream logistics flexibility, strong domestic sales network including integration with its retail network, export capabilities and storage capacity to deliver refinery crude throughput of 433,200 bbls/d in 2022, and industry-leading utilization rates of 93%, compared to 415,500 bbls/d and 89% in the prior year. The company's Canadian refineries outperformed the Canadian refining utilization industry average by nearly 5%(2) during the year.
- In 2022, as a result of a comprehensive strategic review of its downstream retail business, Suncor announced that it will retain and continue to improve and optimize the Petro-Canada™ retail business.

Strategy and Investment Update

The R&M business is a key component of Suncor's integrated business model and serves to maximize Suncor's integrated returns by extending the value chain from oil sands production to the end customer, providing the vital link between Suncor's resource base and consumer demand for refined products. The company's integrated model benefits from the unique advantages of its R&M business, including the key structural advantages of its refineries, its extensive marketing and logistics capabilities, and secured market access, enhanced by its marketing and trading expertise.

The company's refineries are equipped with several key structural advantages, including Suncor's feedstock advantage, which enables the company to process a heavy crude slate with a high-quality output, while operating in geographically advantaged markets with consistent access to low-cost feedstock. The company aims to achieve strong reliability and industry-leading refinery utilizations, allowing the company to provide a reliable supply of products to its secured and competitive sales channels, including its extensive wholesale and retail network, while also operating at optimal levels of utilization to provide reliable offtake for a portion of the production from the Oil Sands segment.

The R&M business is strengthened by the company's marketing and trading expertise by optimizing the supply of crude and natural gas liquids feedstock to the company's four refineries, managing crude inventory levels during refinery turnarounds and periods of unplanned maintenance, and mitigating external impacts from pipeline disruptions. The marketing and logistics organization also moves Suncor's refinery production to market and ensures supply to Suncor's branded retail and wholesale marketing channels.

The company's secured sales channels include the Petro-Canada™ brand, which is recognized as Canada's #1 fuel brand, (3) with nearly 1,600 retail sites and over 300 PETRO-PASS™ sites located in key metropolitan areas across Canada. Suncor's branded retail and wholesale marketing channels provide secure, reliable offtake for a large portion of Suncor's refinery production. The retail and wholesale business generates stable, low-risk cash flows for Suncor with strong fuel volumes being supported by non-fuel offerings in the retail space, and is a part of Suncor fully maximizing the value of each barrel and capturing incremental margin above refinery crack spreads.

(1) The estimated impact of the LIFO method is a non-GAAP financial measure. FIFO inventory valuation includes the impact of commodity risk management activities. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(2) Source: Canada Energy Regulator – https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/crude-oil-petroleum-products/statistics/weekly-crude-run-summary-data/index.html
(3) Based on Kalibrate survey data for year-end 2021.

In 2022, Suncor, with the support of external advisors, completed a comprehensive strategic review of its downstream retail business. As a result of the review, the company announced that it will retain and continue to optimize the Petro-Canada™ retail business, with the goal of further strengthening Suncor's integrated R&M business and driving increased long-term value for shareholders. The enhancement of Suncor's retail business will include changing the mix ownership model of the company-owned and controlled, dealer-owned and partnership sites. Economic investment in 2023 is expected to be focused on company-owned and controlled sites, in the most profitable sites and markets, while optimizing the non-company-controlled sites in less densely populated areas using alternative ownership structures and partnerships to grow the brand's scale and presence. These activities will also include the continued expansion of strategic partnerships in non-fuel related businesses such as quick service restaurants, convenience stores, loyalty partnerships and energy transition offerings to provide low-carbon solutions to customers.

Sustaining capital for 2023 is expected to be focused on ongoing sustainment and enhancement to refinery operations, further driving reliable operations.

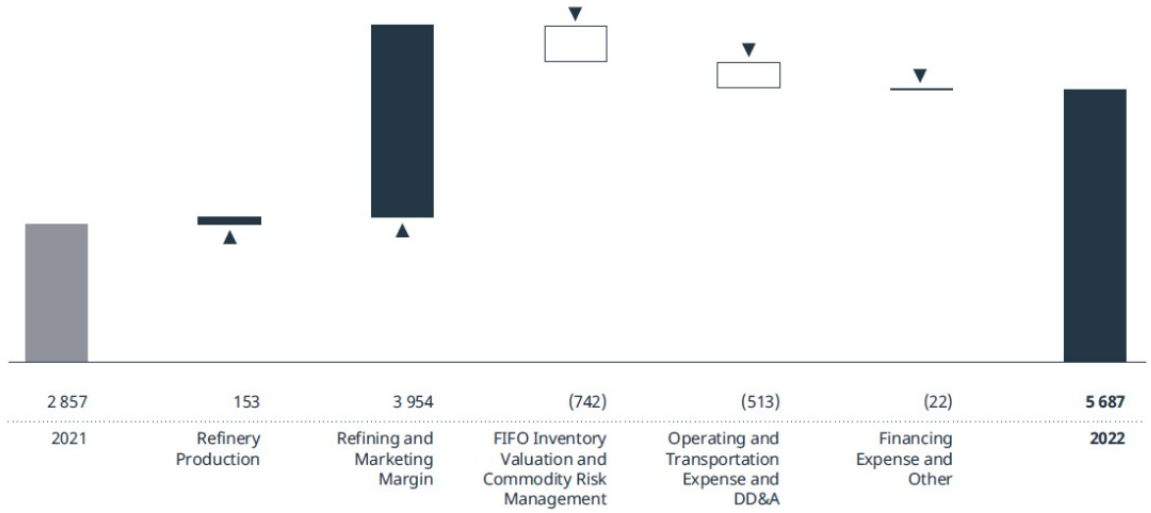
Table of Contents

Financial Highlights

Year ended December 31 ($ millions)	2022	2021	2020
Operating revenues	**36 728**	22 915	15 272
Earnings before income taxes (1)	**5 694**	2 867	1 167
Adjusted for:			
Unrealized (gain) loss on risk management activities (2)	**(7)**	(10)	22
Adjusted operating earnings (1)(3)	**5 687**	2 857	1 189
Adjusted funds from operations (1)(3)	**6 561**	3 831	2 033

(1) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated net earnings (loss), adjusted operating earnings (loss) and adjusted funds from (used in) operations. Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.
(2) Beginning in 2021, the company revised its calculation of adjusted operating earnings, a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been revised to reflect this change.
(3) Non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

Bridge Analysis of Adjusted Operating Earnings ($ millions)(1)(2)



(1) For an explanation of the construction of this bridge analysis, see the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(2) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated adjusted operating earnings (loss). Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.

R&M contributed annual adjusted operating earnings of $5.687 billion in 2022, compared with $2.857 billion in 2021. The increase was primarily due to a significant increase in refining and marketing margins as a result of significantly higher benchmark crack spreads compared to the prior year, and higher crude throughput, partially offset by a smaller FIFO inventory valuation gain compared to the prior year, and an increase in operating and transportation expenses. In 2022, adjusted operating earnings included a before-tax FIFO inventory valuation gain, including the impact of commodity risk management activities, of $230 million, compared to a $972 million gain in 2021, resulting in an unfavourable year-over-year impact of $742 million.

R&M earnings before income taxes in 2022 increased to $5.694 billion compared to $2.867 billion in 2021. In addition to the factors impacting adjusted operating earnings, earnings before income taxes in 2022 included a $7 million unrealized gain on risk management activities, compared to a $10 million gain in the prior year.

R&M achieved annual adjusted funds from operations of $6.561 billion in 2022, compared to $3.831 billion in 2021, due primarily to the same factors that impacted adjusted operating earnings described above.

Table of Contents

Volumes

Year ended December 31	2022	2021	2020
Crude oil processed (mbbls/d)			
Eastern North America	**206.2**	202.8	201.0
Western North America	**227.0**	212.7	206.0
Total	**433.2**	415.5	407.0
Refinery utilization[1][2] (%)			
Eastern North America	**93**	91	91
Western North America	**93**	87	86
Total	**93**	89	88
Refined product sales (mbbls/d)			
Gasoline	**227.6**	225.8	214.1
Distillate	**244.6**	228.5	215.7
Other	**81.4**	74.1	73.6
Total	**553.6**	528.4	503.4
Refining and marketing gross margin – FIFO [3] ($/bbl)	**55.85**	36.85	25.30
Refining and marketing gross margin – LIFO [3] ($/bbl)	**54.45**	30.90	28.65
Refining operating expense[3] ($/bbl)	**7.00**	5.95	5.50

(1) Refinery utilization is the amount of crude oil and natural gas plant liquids run through crude distillation units, expressed as a percentage of the capacity of these units.
(2) The Edmonton refinery crude processing capacity increased to 146,000 bbls/d in 2021 from 142,000 bbls/d in 2020.
(3) Contains non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

Refinery crude throughput increased to 433,200 bbls/d and refinery utilization averaged 93% in 2022, compared to refinery crude throughput of 415,500 bbls/d and refinery utilization of 89% in 2021, reflecting strong utilizations across all refineries in 2022.

Total refined product sales increased to 553,600 bbls/d in 2022, compared to 528,400 bbls/d in 2021. The increase in refined product sales reflected strong utilizations during the year, increased demand and the company's ability to leverage its extensive domestic sales network and export channels.

Refining and Marketing Gross Margins (1)

Refining and marketing gross margins were influenced by the following:

- On a LIFO(2) basis, Suncor's refining and marketing gross margin increased to $54.45/bbl in 2022 from $30.90/bbl in the prior year due to significantly higher benchmark crack spreads resulting from increased demand and declining North American refined product inventories, the widening of heavy crude oil differentials and the impact of a weaker Canadian dollar in relation to the U.S. dollar. Suncor's refining and marketing gross margin also reflects Suncor's feedstock advantage, which enables the company to process heavier crude oil, marketing and logistics capabilities and strong sales channels within its integrated retail and wholesale networks. These factors were partially offset by tightened location and quality differentials from regional benchmarks to the company's local markets and increased environmental compliance costs. On a LIFO basis, Suncor's refining and marketing gross margin represents 92% margin capture compared to Suncor's 5-2-2-1 index in 2022, compared to 93% in 2021.

- On a FIFO basis, Suncor's refining and marketing gross margin increased to $55.85/bbl in 2022, from $36.85/bbl in the prior year due to the same factors noted above, in addition to FIFO inventory valuation impacts. In 2022, the impact of the FIFO method of inventory valuation, relative to an estimated LIFO(2) accounting method, including the impact of commodity risk management activities, resulted in a gain of $230 million. In 2021, FIFO, including the impact of commodity risk management activities, resulted in a gain of $972 million, for an overall unfavourable year-over-year impact of $742 million.

Expenses and Other Factors

R&M operating and transportation expenses increased compared to the prior year due to increased natural gas and power prices, increased maintenance and higher refined product sales volumes.

Refining operating expense per barrel (1) was $7.00 in 2022, compared to $5.95 in the prior year, with the increase primarily due to increased absolute costs, as detailed above, partially offset by higher production.

Planned Maintenance

Planned turnaround maintenance is scheduled at the company's Edmonton and Sarnia refineries in the second quarter of 2023. The anticipated impact of these maintenance events has been reflected in the company's 2023 guidance.

(1) Contains non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(2) The estimated impact of the LIFO method is a non-GAAP financial measure. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

Corporate and Eliminations

2022 Highlights

- In 2022, Suncor returned a total of approximately $7.7 billion of value to its shareholders, compared to approximately $3.9 billion in the prior year. Record shareholder returns in 2022 included approximately $2.6 billion of dividends paid and approximately $5.1 billion in share repurchases. In 2022, the company repurchased a record 116.9 million common shares at an average price of $43.92 per common share, or the equivalent of 8.1% of its issued and outstanding common shares as at December 31, 2021.
- Demonstrating management's confidence in the company's ability to generate sustainable and increasing cash flows, the company increased its dividend per share twice in 2022, most recently in the fourth quarter, to $0.52 per share, which represents a 23.8% increase over the fourth quarter of 2021 dividend and the highest quarterly dividend per share in the company's history.
- In 2022, the company reduced net debt by approximately $3.2 billion excluding the impacts of a $729 million unrealized foreign exchange loss on the revaluation of U.S. dollar denominated debt, representing a net debt reduction of over $2.5 billion. The significant debt reduction provides ongoing balance sheet flexibility, reduces long-term financing costs and demonstrates the company's commitment to reducing net debt.
- Subsequent to 2022, the Board approved a renewal of the company's NCIB for the repurchase of up to 10% of Suncor's public float as at February 3, 2023, over a twelve-month period, and concurrently, the TSX accepted a notice filed by Suncor to renew its NCIB in respect of the repurchase of such shares.
- In 2022, the company reached an agreement for the sale of its wind and solar assets for gross proceeds of approximately $730 million, before closing adjustments and other closing costs. Subsequent to 2022, the company completed the sale of its wind and solar assets for an estimated after-tax gain on sale of approximately $260 million.
- To help reach Suncor's strategic objective to be net-zero by 2050, the company has continued to work collaboratively with industry peers through the Pathways Alliance and with federal and provincial governments during 2022. Significant progress has been achieved to advance the Pathways Alliance's foundational carbon capture project and, subsequent to 2022, the Pathways Alliance was awarded exploratory rights from the Government of Alberta for the proposed carbon capture and storage hub to safely and permanently store CO_2 captured from over 20 oil sands facilities in northern Alberta.

Strategy and Investment Update

The company is committed to allocating excess funds in accordance with its capital allocation framework; strengthening its balance sheet through debt reductions and maximizing shareholder returns, as demonstrated by the company's progress in 2022 related to debt reductions, dividend increases and share repurchases. Looking ahead in 2023, the company will remain disciplined in the execution of its capital allocation framework. Based on current business plans and commodity pricing, the company expects to increase its share buyback allocation to 75% by the end of the first quarter of 2023, and to continue to progress towards its net debt reduction targets in 2023.

Suncor's focus is to sustainably grow its dividend, maximizing returns to shareholders through a dividend that can be sustained through all price cycles. Dividend growth will be considered as momentum and financial results are demonstrated through reliable operational performance and optimization of the business. As well, as the company executes share buybacks, the lower outstanding share count will allow the company to increase its per-share dividend without impacting the dividend breakeven.

Suncor's objective is to be a net-zero GHG emissions company by 2050 and to substantially contribute to society's net-zero ambitions, and the company has set ambitious near-term goals to reduce emissions across its value chain. The Corporate segment includes investments in energy expansion that are in line with, or synergistic with, Suncor's core capabilities and assets, including investments in renewable fuels and hydrogen. Strategic equity investments in two biofuel companies that are currently progressing renewable fuel technology projects are examples of how the company is progressing its GHG reduction objectives. The Varennes Carbon Recycling facility, a biofuel plant in Varennes, Quebec, that is currently under construction, is designed to convert commercial and industrial non-recyclable waste into biofuels and renewable chemicals. In addition, the company has also invested in LanzaJet, Inc., a company working to bring sustainable aviation fuel and renewable diesel to the commercial market. Fabrication of a commercial biorefinery plant near Soperton, Georgia, is well underway and is expected to be operational by the end of 2023 and will supply sustainable low-emissions aviation fuel to customers. From a

design perspective, both projects are being constructed using a method that is expected to be able to be replicated, enabling faster deployments to capture the sizable growth opportunities projected for renewable liquid fuels should economics be attractive. Suncor believes these investments complement its existing biofuels business and demonstrate the company's commitment to being a leader in the global energy expansion.

In addition, in 2021, Suncor and ATCO Ltd. announced a partnership on a potential world-scale clean hydrogen project to be developed in Alberta, Canada, that would connect to the company's Edmonton refinery. A sanctioning decision is expected in 2024 and the facility could be operational as early as 2028, provided it has the required regulatory and fiscal support to render it economic. The project would significantly advance Suncor and Alberta's hydrogen strategy, generate substantial economic activity and make a large contribution towards Suncor and society's net-zero GHG ambitions.

To allow greater focus and investment in hydrogen and renewable fuels, subsequent to 2022, the company completed the sale of its wind and solar assets, for gross proceeds of approximately $730 million, before closing adjustments and other closing costs, resulting in an estimated after-tax gain on sale of approximately $260 million.

Suncor also continues to work collaboratively with industry peers through the Pathways Alliance and with federal and provincial governments. The Pathways Alliance is exploring several parallel pathways to address GHG emissions, including the creation of a carbon capture, utilization and storage trunkline connected to a carbon sequestration hub to enable multi-sector "tie-in" projects as well as the implementation of other next-generation technologies. Significant progress has been achieved to progress the Pathways Alliance's foundational carbon capture project, which is an essential part of the path to net-zero. Subsequent to 2022, the Pathways Alliance was awarded exploratory rights from the Government of Alberta for the proposed carbon capture and storage hub to safely and permanently store CO_2 captured from over 20 oil sands producers in northern Alberta.

By the end of 2022, the company achieved approximately $865 million of incremental free funds flow [(1)] through the implementation of digital, process and technology initiatives. The operating costs portion of the savings generated from these improvement initiatives is partially offsetting inflationary pressures and increased mining scope in the company's Oil Sands business. As discussed at Suncor's investor day, the company will no longer be tracking the impact of each free funds flow initiative making up the $2.15 billion incremental free funds flow target on a consolidated basis, due to the evolving business environment, continuing inflationary pressures and changing mine scopes versus the 2019 base line. The company still expects to continue to deliver on the initiatives it has previously communicated, such as the cogeneration facility at Oil Sands Base, autonomous haul systems, and tailings initiatives.

(1) Non-GAAP financial measure. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

Financial Highlights

Year ended December 31 ($ millions)	2022	2021	2020
Loss before income taxes[1]	**(2 232)**	(1 913)	(937)
Adjusted for:			
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**729**	(113)	(312)
Restructuring charge	**—**	168	—
Loss on early repayment of long-term debt	**—**	80	—
Adjusted operating loss[1][2]	**(1 503)**	(1 778)	(1 249)
Corporate and Renewables	***(1 456)***	*(1 588)*	*(1 370)*
Eliminations - Intersegment profit (eliminated) realized	***(47)***	*(190)*	*121*
Adjusted funds used in operations[1][2]	**(1 240)**	(1 705)	(1 275)

(1) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated net earnings (loss), adjusted operating earnings (loss) and adjusted funds from (used in) operations. Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.
(2) Non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

Year ended December 31	2022	2021	2020
Renewable Energy power generation marketed (gigawatt hours)[1]	**282**	183	200

(1) Power generated includes curtailed production for which the company was compensated.

Corporate and Renewables

The adjusted operating loss for Corporate decreased to $1.456 billion in 2022, compared to $1.588 billion in 2021. The decrease in adjusted operating loss was primarily due to a net decrease in interest expense on debt as a result of debt reductions that occurred throughout 2022, an unrealized gain on investment recorded in the first quarter of 2022, increased costs in the prior year related to costs associated with digital and technology improvements, and an increase in interest revenue on the company's cash and short-term investment balances. The decreased loss was partially offset by a larger share-based compensation expense in 2022 versus 2021, and increased costs associated with the early redemption of long-term debt in the fourth quarter of 2022.

Suncor capitalized $168 million of its borrowing costs in 2022, compared to $144 million in 2021, as part of the cost of major development assets and construction projects in progress.

Eliminations – Intersegment Profit Realized (Eliminated)

Eliminations reflect the deferral or realization of profit on crude oil sales from Oil Sands to Suncor's refineries. Consolidated profits are only realized when the refined products produced from internal purchases of crude feedstock have been sold to third parties. In 2022, the company deferred $47 million of intersegment profit, compared to a deferral of profit of $190 million in the prior year. The deferral of profit in 2022 was driven by the increase in Oil Sands price realizations in 2022, as lower margin crude refinery feedstock sourced internally from Oil Sands was sold and replaced by higher margin crude inventory, resulting in a deferral of profit at the enterprise level.

Adjusted funds used in operations for the Corporate and Eliminations segment were $1.240 billion in 2022, compared to $1.705 billion in 2021, and were influenced by the same factors that impacted adjusted operating loss, excluding the impact of the non-cash component of share-based compensation expense, the unrealized gain on investment recorded in the first quarter of 2022, and the impact of costs associated with the early redemption of long-term debt in the fourth quarter of 2022.

Table of Contents

5. Income Tax

Year ended December 31 ($ millions)	2022	2021	2020
Current income tax expense (recovery)	**4 229**	1 395	(659)
Deferred income tax expense (recovery)	**(990)**	56	(1 119)
Income tax expense (recovery) included in net earnings (loss)	**3 239**	1 451	(1 778)
Less: income tax (recovery) expense excluded from adjusted operating earnings [1]	**(915)**	5	(747)
Income tax expense (recovery) included in adjusted operating earnings	**4 154**	1 446	(1 031)
Effective tax rate	**26.3%**	26.1%	16.9%

(1) In 2022, income tax (recovery) expense excluded from adjusted operating earnings includes a deferred income tax recovery of $171 million related to the anticipated sale of the company's U.K. E&P portfolio and a current income tax recovery of $39 million related to the sale of its wind and solar assets.

The provision for income taxes in 2022 increased compared to the prior year, primarily due to increased earnings. In 2022, the company's effective tax rate on net earnings was comparable to the prior year.

6. Fourth Quarter 2022 Analysis

Financial and Operational Highlights

Three months ended December 31 ($ millions, except as noted)	2022	2021
Earnings (loss) before income taxes [1]		
Oil Sands	**1 625**	1 169
Exploration and Production	**578**	603
Refining and Marketing	**1 517**	599
Corporate and Eliminations	**(182)**	(317)
Income tax expense	**(797)**	(501)
Net earnings	**2 741**	1 553
Adjusted operating earnings (loss) [1][2]		
Oil Sands	**1 719**	1 172
Exploration and Production	**578**	376
Refining and Marketing	**1 529**	582
Corporate and Eliminations	**(382)**	(342)
Income tax expense included in adjusted operating earnings	**(1 012)**	(494)
Total	**2 432**	1 294
Adjusted funds from (used in) operations [1]		
Oil Sands	**2 929**	2 459
Exploration and Production	**719**	565
Refining and Marketing	**1 663**	869
Corporate and Eliminations	**(273)**	(252)
Current income tax expense	**(849)**	(497)
Total adjusted funds from operations	**4 189**	3 144
Changes in non-cash working capital	**(265)**	(529)
Cash flow provided by operating activities	**3 924**	2 615
Production volumes (mboe/d)		
Oil Sands – Upgraded – net SCO and diesel	**517.5**	515.0
Oil Sands – Non-upgraded bitumen	**170.6**	150.9
Exploration and Production	**75.0**	77.4
Total	**763.1**	743.3

(1) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated net earnings (loss), adjusted operating earnings (loss) and adjusted funds from (used in) operations. Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.

(2) Non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

Net Earnings

Suncor's consolidated net earnings for the fourth quarter of 2022 were $2.741 billion, compared to $1.553 billion in the prior year quarter. Net earnings were primarily influenced by the same factors that impacted adjusted operating earnings described in this section.

Other items affecting net earnings over these periods included:

- An unrealized foreign exchange gain on the revaluation of U.S. dollar denominated debt of $200 million recorded in financing expenses in the Corporate and Eliminations segment in the fourth quarter of 2022, compared to a gain of $25 million in the fourth quarter of 2021.
- An unrealized loss on risk management activities of $106 million recorded in other income (loss) in the fourth quarter of 2022, compared to a gain of $14 million in the fourth quarter of 2021.
- During the fourth quarter of 2021, the company recorded a gain of $227 million on the sale of the company's interest in the Golden Eagle Area Development, which was completed early in the fourth quarter of 2021 and recorded in the E&P segment.
- An income tax recovery excluded from adjusted operating earnings of $215 million in the fourth quarter of 2022, compared to an expense of $7 million in the fourth quarter of 2021.

Adjusted Funds From Operations and Cash Flow Provided by Operating Activities

Adjusted funds from operations increased to $4.189 billion ($3.11 per common share) in the fourth quarter of 2022, compared to $3.144 billion ($2.17 per common share) in the prior year quarter. Adjusted funds from operations were influenced by the same factors impacting adjusted operating earnings noted above.

Cash flow provided by operating activities, which includes changes in non-cash working capital, increased to $3.924 billion ($2.91 per common share) in the fourth quarter of 2022, compared to $2.615 billion ($1.80 per common share) in the prior year quarter. In addition to the factors impacting adjusted funds from operations, cash flow provided by operating activities was impacted by a smaller use of cash associated with the company's working capital balances in the fourth quarter of 2022 compared to the prior year quarter.

Segmented Analysis

Oil Sands

The Oil Sands segment adjusted operating earnings increased to $1.719 billion in the fourth quarter of 2022, compared to $1.172 billion in the prior year quarter, primarily due to higher realized crude oil prices, lower depreciation, depletion and amortization (DD&A), and higher sales. The increase in adjusted operating earnings was partially offset by increased operating expenses, related primarily to increased commodity input costs and maintenance.

The company's net SCO production was 517,500 bbls/d in the fourth quarter of 2022, comparable to 515,000 bbls/d in the prior year quarter. Increased SCO production at Syncrude, reflecting 99% upgrader utilization in the fourth quarter of 2022, compared to 90% in the prior year quarter, was partially offset by decreased production at Oil Sands Base as the current quarter was impacted by the completion of planned maintenance activities that commenced in the third quarter of 2022.

The company's non-upgraded bitumen production increased to 170,600 bbls/d in the fourth quarter of 2022, compared to 150,900 bbls/d in the fourth quarter of 2021, primarily due to increased production from Fort Hills and record quarterly production from Firebag.

Non-upgraded bitumen production from the company's In Situ assets in the fourth quarter of 2022 was higher than the prior year quarter, with an overall increase in bitumen production volumes being partially offset by increased Firebag production being diverted to upgrading in the current period, as the prior year quarter was impacted by maintenance activities at Firebag. During the fourth quarter of 2022, the company also leveraged its asset flexibility and marketing and trading expertise, including its midstream and logistics network, to mitigate third-party pipeline disruptions, resulting in additional non-upgraded bitumen production being sold to market.

SCO and diesel sales volumes increased to 505,300 bbls/d in the fourth quarter of 2022, compared to 496,100 bbls/d in the prior year quarter, and were impacted by a smaller build of inventory in the current quarter compared to the prior year quarter, as well as the same factors that affected production volumes, discussed above.

Non-upgraded bitumen sales volumes were 174,500 bbls/d in the fourth quarter of 2022, compared to 176,700 bbls/d in the prior year quarter, and were impacted by a larger draw of inventory in the prior year quarter, which was partially offset by the increase in production volumes in the current quarter, discussed above.

Exploration and Production

Adjusted operating earnings for the E&P segment in the fourth quarter of 2022 increased to $578 million compared to $376 million in the prior year quarter, with the increase primarily due to significantly higher realized crude prices and higher sales volumes in the fourth quarter of 2022, partially offset by increased operating and transportation expenses.

Production volumes for E&P Canada were 49,100 bbls/d in the fourth quarter of 2022, compared to 47,600 bbls/d in the prior year quarter, primarily due to increased production related to the company's additional working interest in White Rose and strong production at Hebron, partially offset by the impact of planned turnaround activities at Hibernia in the fourth quarter of 2022.

In E&P Canada, investment in the Terra Nova FPSO facility related to the ALE Project was substantially progressed in 2022, and the asset has returned to Canada, with a safe return to production expected in the second quarter of 2023.

E&P International production was 25,900 boe/d in the fourth quarter of 2022, compared to 29,800 boe/d in the prior year quarter, primarily due to the sale of the company's assets in Norway in the third quarter of 2022 and the Golden Eagle Area Development in the fourth quarter of 2021, and natural declines, partially offset by increased liftings at Libya in the fourth quarter of 2022 compared to the prior year quarter.

Total E&P sales volumes were 75,100 boe/d in the fourth quarter of 2022, compared to 67,200 boe/d in the prior year quarter, primarily due to a draw of inventory at E&P international in the current quarter, and a build of inventory at E&P Canada in both periods, associated with the timing of cargo sales at year-end.

Refining and Marketing

R&M adjusted operating earnings in the fourth quarter of 2022 increased to $1.529 billion compared to $582 million in the prior year quarter. The increase in adjusted operating earnings was primarily due to a significant increase in refining and marketing margins as a result of significantly higher benchmark crack spreads in the current period, which was partially offset by a FIFO inventory valuation loss in the current period, compared to a gain in the prior year quarter, and increased operating and transportation expenses, primarily due to increased commodity input costs. In the fourth quarter of 2022, adjusted operating earnings included a before-tax FIFO inventory valuation loss, including the impact of commodity risk management activities, of $439 million on the decrease in crude and refined product benchmarks, compared to a $161 million gain in the prior year quarter.

Refinery crude throughput was 440,000 bbls/d and refinery utilization was 94% in the fourth quarter of 2022, compared to 447,000 bbls/d and 96% in the prior year quarter, with the decrease due to unplanned maintenance in the current period, including the weather-related event that occurred late in the quarter at the company's Commerce City refinery. Refined product sales in the fourth quarter of 2022 were 548,200 bbls/d, comparable to 550,100 bbls/d in the prior year quarter.

Progressive restart activities at the company's Commerce City refinery are currently underway, and the asset is anticipated to return to normal production rates by the end of the first quarter.

Corporate and Eliminations

Corporate incurred an adjusted operating loss of $482 million in the fourth quarter of 2022, compared to $376 million in the prior year quarter. The increased loss was attributable to an operational foreign exchange loss in the current quarter, compared to a gain in the prior year quarter, increased costs associated with the early redemption of long-term debt in the fourth quarter of 2022, and increased OS&G expenses, which were partially offset by a net decrease in interest expense on debt in the current quarter as a result of debt reductions that occurred throughout 2022, and an increase in interest revenue on the company's cash and short-term investment balances. Increased OS&G expenses in the fourth quarter of 2022 compared to the prior year quarter were primarily due to increased investment related to the company's progress towards its net-zero GHG emissions objective and digital transformation. Suncor capitalized $44 million of its borrowing costs in the fourth quarter of 2022, as part of the cost of major development assets and construction projects in progress, compared to $38 million in the prior year quarter.

Eliminations reflect the deferral or realization of profit or loss on crude oil sales from Oil Sands to Suncor's refineries. Consolidated profits and losses are only realized when the refined products produced from internal purchases of crude

feedstock have been sold to third parties. During the fourth quarter of 2022, the company realized $100 million of intersegment profit, compared to a realization of $34 million of intersegment profit in the prior year quarter. The realization of intersegment profit and elimination of unrealized losses in the fourth quarter of 2022 was driven by a weakening in benchmark pricing in the current period.

Table of Contents

7. Quarterly Financial Data

Financial Summary

Three months ended ($ millions, unless otherwise noted)	**Dec 31 2022**	Sept 30 2022	June 30 2022	Mar 31 2022	Dec 31 2021	Sept 30 2021	June 30 2021	Mar 31 2021
Total production (mboe/d)								
Oil Sands	**688.1**	646.0	641.5	685.7	665.9	605.1	615.7	690.6
Exploration and Production	**75.0**	78.1	78.7	80.4	77.4	93.5	84.0	95.3
	763.1	724.1	720.2	766.1	743.3	698.6	699.7	785.9
Revenues and other income								
Operating revenues, net of royalties[1]	**13 920**	14 944	16 135	13 337	11 149	10 145	9 159	8 679
Other (loss) income	**(65)**	113	69	14	10	68	(66)	(43)
	13 855	15 057	16 204	13 351	11 159	10 213	9 093	8 636
Net earnings (loss)	**2 741**	(609)	3 996	2 949	1 553	877	868	821
per common share – basic (dollars)	**2.03**	(0.45)	2.84	2.06	1.07	0.59	0.58	0.54
per common share – diluted (dollars)	**2.03**	(0.45)	2.83	2.06	1.07	0.59	0.58	0.54
Adjusted operating earnings[2]	**2 432**	2 565	3 814	2 755	1 294	1 043	722	746
per common share[3][4] (dollars)	**1.81**	1.88	2.71	1.92	0.89	0.71	0.48	0.49
Adjusted funds from operations[2]	**4 189**	4 473	5 345	4 094	3 144	2 641	2 362	2 110
per common share[3][4] (dollars)	**3.11**	3.28	3.80	2.86	2.17	1.79	1.57	1.39
Cash flow provided by operating activities	**3 924**	4 449	4 235	3 072	2 615	4 718	2 086	2 345
per common share[4] (dollars)	**2.91**	3.26	3.01	2.14	1.80	3.19	1.39	1.54
ROCE[3] (%) for the twelve months ended	**19.4**	17.5	19.4	12.7	8.6	4.5	1.9	(1.4)
ROCE excluding impairments and impairment reversals[3](%) for the twelve months ended	**22.9**	21.0	18.2	12.4	8.2	4.9	2.6	(0.6)
Common share information (dollars)								
Dividend per common share	**0.52**	0.47	0.47	0.42	0.42	0.21	0.21	0.21
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**42.95**	38.90	45.16	40.70	31.65	26.26	29.69	26.27
New York Stock Exchange (US$)	**31.73**	28.15	35.07	32.59	25.03	20.74	23.97	20.90

(1) The company revised certain gross revenues and purchases of crude oil and products to align with the current period presentation. For the three months ended March 31, 2022, gross revenues and purchases of crude oil and products was decreased by $150 million, with no effect on net earnings.

(2) Non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A. Adjusted operating earnings (loss) for each quarter are defined in the Non-GAAP and Other Financial Measures Advisory section and reconciled to GAAP measures in the Consolidated Financial Information and Segment Results and Analysis sections of each Quarterly Report to Shareholders issued by Suncor (Quarterly Reports) in respect of the relevant quarter. Adjusted funds from operations for each quarter are defined and reconciled to GAAP measures in the Non-GAAP and Other Financial Measures Advisory section of each Quarterly Report in respect of the relevant quarter, with such information being incorporated by reference herein and available on SEDAR at www.sedar.com.

(3) Contains non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A. Non-GAAP measures included in ROCE and ROCE excluding impairments and impairment reversals are defined and reconciled to GAAP measures in the Non-GAAP and Other Financial Measures Advisory section of each Quarterly Report in respect of the relevant quarter, with such information being incorporated by reference herein and available on SEDAR at www.sedar.com.

(4) Represented on a basic per share basis.

Business Environment

Three months ended (average for the period ended, except as noted)		**Dec 31 2022**	Sept 30 2022	June 30 2022	Mar 31 2022	Dec 31 2021	Sept 30 2021	June 30 2021	Mar 31 2021
WTI crude oil at Cushing	US$/bbl	**82.65**	91.65	108.40	94.40	77.15	70.55	66.05	57.80
Dated Brent crude	US$/bbl	**88.65**	100.95	113.75	101.50	79.70	73.45	68.85	60.85
Dated Brent/Maya FOB price differential	US$/bbl	**17.70**	17.95	11.65	14.30	8.60	7.80	6.20	4.70
MSW at Edmonton	Cdn$/bbl	**110.05**	116.85	137.80	115.75	93.25	83.75	77.25	66.55
WCS at Hardisty	US$/bbl	**57.00**	71.75	95.60	79.80	62.50	56.95	54.60	45.40
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**(25.65)**	(19.90)	(12.80)	(14.60)	(14.65)	(13.60)	(11.45)	(12.40)
SYN-WTI (differential) premium	US$/bbl	**4.15**	8.80	6.05	(1.30)	(1.80)	(1.60)	0.35	(3.50)
Condensate at Edmonton	US$/bbl	**83.40**	87.35	108.35	96.15	79.10	69.20	66.40	58.00
Natural gas (Alberta spot) at AECO	Cdn$/GJ	**4.90**	4.15	6.90	4.50	4.45	3.40	2.95	2.95
Alberta Power Pool Price	Cdn$/MWh	**213.95**	221.40	122.45	90.00	107.30	100.35	104.50	95.45
New York Harbor 2-1-1 crack (1)	US$/bbl	**52.75**	46.70	60.05	28.25	20.65	20.90	20.35	15.60
Chicago 2-1-1 crack (1)	US$/bbl	**39.20**	43.30	49.40	20.20	16.90	20.45	20.25	13.40
Portland 2-1-1 crack (1)	US$/bbl	**50.70**	57.30	63.45	33.80	25.35	26.70	24.55	15.80
Gulf Coast 2-1-1 crack (1)	US$/bbl	**40.20**	41.85	52.55	26.80	19.65	19.55	18.25	14.45
U.S. Renewable Volume Obligation	US$/bbl	**8.55**	8.10	7.80	6.45	6.10	7.35	8.15	5.50
Exchange rate	US$/Cdn$	**0.74**	0.77	0.78	0.79	0.79	0.79	0.81	0.79
Exchange rate (end of period)	US$/Cdn$	**0.74**	0.73	0.78	0.80	0.79	0.78	0.81	0.80

(1) 2-1-1 crack spreads are indicators of the refining margin generated by converting two barrels of WTI into one barrel of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Significant or Unusual Items Impacting Net Earnings (Loss)

Trends in Suncor's quarterly revenue, net earnings (loss) and adjusted funds from operations are driven primarily by production volumes, which can be significantly impacted by major maintenance events, changes in commodity prices and crude price differentials, refining crack spreads and foreign exchange rates as described in the Financial Information section of this MD&A. Trends in Suncor's quarterly net earnings (loss) and adjusted funds from operations are also affected by other significant events impacting operations, such as the COVID-19 pandemic beginning in the first quarter of 2020 and operational incidents.

In addition to the impacts of changes in production volumes and business environment, net earnings (loss) over the last eight quarters were affected by the following events or significant adjustments:

- During the third quarter of 2022, in connection with the company entering into a conditional agreement to acquire Teck's interest in Fort Hills, as well as updates to the Fort Hills long-range plan including production and operating cost plans, the company recorded a non-cash impairment of $3.397 billion before-tax against its share of the Fort Hills assets.
- During the third quarter of 2022, the company recognized $147 million of property damage insurance proceeds, in other income, related to the company's assets in Libya in the E&P segment.
- During the third quarter of 2022, the company recorded a $65 million foreign exchange loss related to the sale of the company's share of its assets in Norway, in the E&P segment.
- During the second quarter of 2022, as a result of the decision to restart the West White Rose Project, the company recorded a non-cash impairment reversal of $715 million before-tax on its share of the White Rose assets, in the E&P segment. Also during the second quarter of 2022, as a result of the company's expected sale of its E&P assets in

Norway, and the subsequently reached agreement for such sale, the company recorded a non-cash impairment of $70 million before-tax against its share of its assets in Norway.

- During the fourth quarter of 2021, the company recorded a gain of $227 million before-tax on the sale of the company's interest in the Golden Eagle Area Development, in the E&P segment.
- During the third quarter of 2021, the company recorded a non-cash impairment reversal of $221 million before-tax against its share of the Terra Nova assets, in the E&P segment, as a result of the ALE Project moving forward and the benefit of royalty and financial support from the Government of Newfoundland and Labrador.
- During the third quarter of 2021, the company recorded a loss of $80 million before-tax for early repayment of long-term debt in financing expenses in the Corporate and Eliminations segment.
- During the first quarter of 2021, the company recorded a restructuring charge of $168 million before-tax related to workforce reductions in operating, selling and general expenses in the Corporate and Eliminations segment.

Table of Contents

8. Capital Investment Update

Capital and Exploration Expenditures by Segment

Year ended December 31 ($ millions)	2022	2021	2020
Oil Sands	**3 540**	3 168	2 736
Exploration and Production(1)	**443**	270	489
Refining and Marketing	**816**	825	515
Corporate and Eliminations(2)	**188**	292	186
Total capital and exploration expenditures	**4 987**	4 555	3 926
Less: capitalized interest on debt	**(168)**	(144)	(120)
	4 819	4 411	3 806

(1) Excludes capital expenditures related to assets held for sale of $57 million in 2022.
(2) Excludes capital expenditures related to assets held for sale of $76 million in 2022.

Capital and Exploration Expenditures by Type, Excluding Capitalized Interest

Year ended December 31, 2022 ($ millions)	Asset Sustainment and Maintenance(1)	Economic Investment(2)	Total
Oil Sands			
Oil Sands Base	*1 231*	*442*	***1 673***
In Situ	*256*	*287*	***543***
Fort Hills	*336*	*1*	***337***
Syncrude	*746*	*106*	***852***
Exploration and Production(3)	*-*	*420*	**420**
Refining and Marketing	*732*	*84*	**816**
Corporate and Eliminations(4)	*14*	*164*	**178**
	3 315	1 504	**4 819**

(1) Asset sustainment and maintenance capital expenditures include capital investments that deliver on existing value by ensuring compliance or maintaining relations with regulators and other stakeholders, maintaining current processing capacity and delivering existing developed reserves.
(2) Economic investment capital expenditures include capital investments that result in an increase in value through adding reserves and improving processing capacity, utilization, cost or margin, including associated infrastructure.
(3) Excludes capital expenditures related to assets held for sale of $57 million in 2022.
(4) Excludes capital expenditures related to assets held for sale of $76 million in 2022.

In 2022, Suncor's capital expenditures on property, plant and equipment and exploration activities totalled $4.819 billion, excluding capitalized borrowing costs of $168 million, compared to $4.411 billion in 2021, excluding capitalized borrowing costs of $144 million.

Activity in 2022 included the following:

Oil Sands Base

Oil Sands Base asset sustainment and maintenance capital expenditures were $1.231 billion in 2022 and were primarily focused on ensuring continued safe, reliable and efficient operations. The company's planned maintenance program in 2022 included mine and tailings development and planned annual coker maintenance at Upgrader 2 and Upgrader 1.

Oil Sands Base economic capital of $442 million in 2022 was primarily focused on progressing the investment in low-carbon power generation by replacing its coke-fired boilers with a new cogeneration facility.

In Situ

In Situ capital expenditures were $543 million in 2022, of which $287 million was directed towards economic investment activities, which focused on the ongoing design and construction of well pads to develop additional reserves that are expected to maintain existing production levels at Firebag and MacKay River in future years as production from existing well pads declines. Asset sustainment and maintenance capital expenditures of $256 million were primarily directed towards the company's planned maintenance program, including significant planned turnaround activities at Firebag in 2022.

Fort Hills

Fort Hills capital expenditures were $337 million in 2022, the majority of which were directed towards asset sustainment related to mine and tailings development to support ongoing operations, including spend aligned with the execution of its mine improvement plan which commenced in the fourth quarter of 2022 and includes an accelerated sequence of mine development relative to historical plans.

Syncrude

Syncrude capital expenditures were $852 million in 2022, the majority of which were directed toward asset sustainment and maintenance capital expenditures that focused on improving asset reliability, including its planned turnaround which took place in the third quarter and tailings development. Economic investment activities were directed towards progressing the Mildred Lake West Extension mining project.

Exploration and Production

E&P capital and exploration expenditures were $420 million in 2022, and were focused on economic investment projects, primarily related to the Terra Nova ALE Project, net of support from the Government of Newfoundland and Labrador, development work at the West White Rose Project and development drilling at Hebron.

Refining and Marketing

R&M capital expenditures were $816 million in 2022, of which $732 million was directed toward asset sustainment and maintenance capital expenditures that focused on the ongoing sustainment and enhancement of refinery and retail operations. This included planned turnaround activities at the company's Edmonton, Montreal and Sarnia refineries during the year.

R&M economic capital of $84 million in 2022 was primarily directed towards expanding and enhancing the company's sales and marketing business, including investment into the optimization of its retail operations.

Corporate

Corporate capital expenditures were $178 million in 2022, primarily directed towards the company's digital transformation, and the Forty Mile Wind Power Project, prior to the company's wind and solar assets being classified as assets held for sale in the second quarter of 2022.

Suncor anticipates 2023 capital expenditures to be directed to the following projects and initiatives:

Oil Sands operations

For 2023, plans for economic investment include capital to progress low-carbon power generation to replace the coke-fired boilers at Oil Sands Base, which is expected to be in service in late 2024, and capital related to the Upgrader 1 coke drum replacement. Additional investment includes the ongoing design and construction of well pads to develop additional reserves that are expected to maintain existing production levels at Firebag and MacKay River in future years as production from existing well pads declines.

Asset sustainment and maintenance capital expenditures for 2023 are expected to include expenditures relating to tailings management and the company's planned maintenance program, including the significant planned turnaround at Oil Sands Base Upgrader 2.

Fort Hills

Asset sustainment and maintenance capital expenditures for 2023 are expected to focus on ongoing development of mining and tailings management projects to preserve production capacity and execute on the mine improvement plan, which includes an accelerated sequence of mine development relative to historical plans. Asset sustainment and maintenance expenditures for 2023 also include significant planned turnaround activities that are scheduled for the third quarter of 2023.

Syncrude

For 2023, plans for economic investment include capital to progress the Mildred Lake West Extension mining project.

Sustaining capital expenditures for 2023 are expected to focus on planned maintenance and reliability programs aimed at maintaining production capacity. In 2023, this includes planned turnaround activities in the second quarter as well as planned maintenance activities in the fourth quarter.

Exploration and Production

Economic investment for 2023 is expected to be primarily focused on development work at the West White Rose Project, as well as development activities at Hebron and Hibernia.

Refining and Marketing

Sustaining capital expenditures for 2023 are expected to focus on ongoing sustainment of refinery and retail operations, including planned refinery turnaround maintenance.

Economic investment projects in 2023 are expected to be primarily directed towards expanding and enhancing the company's sales and marketing business, including investment into the optimization of its retail and wholesale operations.

Corporate

For 2023, the company plans to continue to make economic investments in digital technology initiatives, as well as investments that support the company's progress towards its net-zero GHG emissions objective.

Table of Contents

9. Financial Condition and Liquidity

Liquidity and Capital Resources

At December 31 ($ millions, except as noted)	2022	2021	2020
Cash flow provided by (used in)			
Operating activities	**15 680**	11 764	2 675
Investing activities	**(4 789)**	(3 977)	(4 524)
Financing activities	**(11 228)**	(7 464)	1 786
Foreign exchange loss on cash and cash equivalents	**112**	(3)	(12)
Increase (decrease) in cash and cash equivalents	**(225)**	320	(75)
Cash and cash equivalents, end of year	**1 980**	2 205	1 885
Return on Capital Employed (%)[1][2]	**19.4**	8.6	(6.9)
Net debt to adjusted funds from operations [1] (times)	**0.8**	1.6	5.1
Total debt to total debt plus shareholders' equity [1] (%)	**28.4**	33.4	37.8
Net debt to net debt plus shareholders' equity [1][3] (%)	**25.7**	30.6	35.7
Net debt to net debt plus shareholders' equity - excluding leases [1][3] (%)	**21.3**	26.6	32.1

(1) Non-GAAP financial measures or contains non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.
(2) ROCE would have been 22.9% for the twelve months ended December 31, 2022, excluding the impact of the impairment reversal of $715 million ($542 million after-tax) and impairment of $70 million ($47 million after-tax) in the second quarter of 2022, and the impact of the impairment of $3.397 billion ($2.586 billion after-tax) in the third quarter of 2022. ROCE would have been 8.2% for the twelve months ended December 31, 2021, excluding the impact of the impairment reversal of $221 million ($168 million after-tax) in the third quarter of 2021. ROCE would have been (2.9%) for the twelve months ended December 31, 2020, excluding the impact of impairments of $559 million ($423 million after-tax) in the fourth quarter of 2020 and $1.821 billion ($1.376 billion after-tax) and $560 million ($422 million after-tax) in the first quarter of 2020.
(3) Beginning in 2021, the company added two supplemental debt metrics that reflect additional information that management uses to evaluate capital management.

Cash Flow Provided by Operating Activities

Cash flow provided by operating activities was $15.680 billion in 2022 compared to $11.764 billion in 2021. The increase was primarily due to higher crude oil and refined product realizations reflecting the improved business environment and higher crude production and refinery crude throughput. These factors were partially offset by an increase in royalties, primarily associated with higher crude price realizations, and increased operating expenses.

The current period cash flow provided by operating activities reflects a use of cash in working capital, primarily due to an increase in inventory balances and accounts receivable related to the increase in commodity prices and crude oil price realizations in 2022, and a net decrease in taxes payable due to income tax instalments paid throughout the year, partially offset by an increase in accounts payable and accrued liabilities. The prior period cash flow provided by operating activities reflects a source of cash in working capital, primarily due to a net increase in taxes payable related to the company's 2021 income tax expense, which was payable in early 2022, and an increase in accounts payable and accrued liabilities, partially offset by an increase in accounts receivable related to an increase in crude oil price realizations during 2021.

Cash Flow Used in Investing Activities

Cash flow used in investing activities was $4.789 billion in 2022 compared to $3.977 billion in 2021. The increase was primarily due to increased capital expenditures in the current year.

Cash Flow (Used in) Provided by Financing Activities

Cash flow used in financing activities was $11.228 billion in 2022, compared to $7.464 billion in 2021. The increase was primarily due to an increase in share repurchases, the significant decrease in long-term debt and increased and dividends, partially offset by a net increase in short-term debt in 2022 compared to a decrease in 2021.

Capital Resources

Suncor's capital resources consist primarily of cash flow provided by operating activities, cash and cash equivalents and available credit facilities, including commercial paper. Suncor's management believes the company will have sufficient capital resources to fund its planned 2023 capital spending program of $5.4 billion to $5.8 billion and to meet current and future working capital requirements through cash and cash equivalents balances, cash flow provided by operating activities,

available committed credit facilities, issuing commercial paper and, if needed, accessing capital markets. The company's cash flow provided by operating activities depends on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates.

The company has invested cash in short-term financial instruments that are presented as cash and cash equivalents. The objectives of the company's short-term investment portfolio are to ensure the preservation of capital, maintain adequate liquidity to meet Suncor's cash flow requirements and deliver competitive returns derived from the quality and diversification of investments within acceptable risk parameters. The maximum weighted average term to maturity of the short-term investment portfolio is not expected to exceed six months, and all investments will be with counterparties with investment grade debt ratings.

Available Sources of Liquidity

Cash and Cash Equivalents

Included in cash and cash equivalents of $1.980 billion at December 31, 2022, are short-term investments with weighted average days to maturity of approximately nine days. In 2022, the company earned approximately $6 million of interest income on these investments.

Financing Activities

Suncor's interest on debt and lease liabilities (before capitalized interest) in 2022 was $982 million, a decrease from $995 million in 2021, due to a significant decrease in long-term debt that occurred over the course of 2022, partially offset by increased interest on short-term debt as a result of a higher short-term debt balance and increased interest rates in 2022.

Available lines of credit at December 31, 2022, decreased to $2.900 billion compared to $4.247 billion at December 31, 2021. The decrease in liquidity was primarily due to an increase in short-term indebtedness. As of December 31, 2022, Suncor had approximately $4.9 billion of liquidity.

A summary of total and unutilized credit facilities at December 31, 2022, is as follows:

($ millions)	2022
Fully revolving and expires in 2025	**3 000**
Fully revolving and expires in 2024	**2 707**
Can be terminated at any time at the option of the lenders	**1 520**
Total credit facilities	**7 227**
Credit facilities supporting outstanding commercial paper	**(2 807)**
Credit facilities supporting standby letters of credit	**(1 148)**
Total unutilized credit facilities[(1)]	**3 272**

(1) Available credit facilities for liquidity purposes were $2.900 billion at December 31, 2021 (December 31, 2020 – $4.427 billion).

Total Debt to Total Debt Plus Shareholders' Equity

Suncor is subject to financial and operating covenants related to its bank debt and public market debt. Failure to meet the terms of one or more of these covenants may constitute an "event of default" as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. The company is in compliance with its financial covenant that requires total debt to not exceed 65% of its total debt plus shareholders' equity. At December 31, 2022, total debt to total debt plus shareholders' equity was 28.4% (December 31, 2021 – 33.4%), a decrease from the prior year due to lower debt levels and higher shareholders' equity as a result of increased net earnings. The company is currently in compliance with all operating covenants as at December 31, 2022.

Change in Debt

($ millions)	2022
Total debt(1) – December 31, 2021	**18 354**
Net decrease in long-term debt	**(5 128)**
Net increase in short-term debt	**1 473**
Increase in lease liability	**524**
Lease payments	**(329)**
Foreign exchange on debt, and other	**725**
Total debt(1) – December 31, 2022	**15 619**
Less: Cash and cash equivalents – December 31, 2022	**1 980**
Net debt(1) – December 31, 2022	**13 639**

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP and Other Financial Measures section of this MD&A.

At December 31, 2022, Suncor's net debt was $13.639 billion, compared to $16.149 billion at December 31, 2021. During 2022, net debt decreased by $2.510 billion, primarily due to a significant decrease long-term debt and lease principal payments made in 2022, partially offset by an increase in short-term indebtedness, unfavourable foreign exchange rates on U.S. dollar denominated debt compared to December 31, 2021, a decrease in cash and cash equivalents relative to the prior year, and leases entered into during the year.

For the year ended December 31, 2022, the company's net debt to adjusted funds from operations measure was 0.8 times, which is lower than management's maximum target of less than 3.0 times.

Credit Ratings

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

As at March 6, 2023, the company's long-term senior debt ratings are:

Long-Term Senior Debt	Rating	Long-Term Outlook
S&P Global Ratings	BBB	Negative
DBRS Morningstar	A (low)	Stable
Moody's Investors Service	Baa1	Stable
Fitch Ratings	BBB+	Stable

As at March 6, 2023, the company's commercial paper ratings are:

Commercial Paper	Cdn Program Rating	U.S. Program Rating
S&P Global Ratings	Not rated	A-2
DBRS Morningstar	R-1 (low)	Not rated
Moody's Investors Service	Not rated	P-2
Fitch Ratings	Not rated	F-1

Refer to the Description of Capital Structure – Credit Ratings section of Suncor's 2022 AIF for a description of credit ratings listed above.

Common Shares

Outstanding Shares

(thousands)	December 31, 2022
Common shares	**1 337 471**
Common share options – exercisable	**16 407**
Common share options – non-exercisable	**4 661**

As at March 3, 2023, the total number of common shares outstanding was 1,326,911,330 and the total number of exercisable and non-exercisable common share options outstanding was 20,507,798. Once exercisable, each outstanding common share option may be exercised for one common share.

Share Repurchases

In the first quarter of 2022, the TSX accepted a notice filed by Suncor to renew its NCIB to repurchase up to 5% of the company's outstanding common shares through the facilities of the TSX, NYSE and/or alternative trading systems. The notice provided that, beginning February 8, 2022, and ending February 7, 2023, Suncor may purchase for cancellation up to 71,650,000 common shares, which is equal to approximately 5% of Suncor's issued and outstanding common shares as at the date hereof. As at January 31, 2022, Suncor had 1,435,748,494 common shares issued and outstanding.

During the second quarter of 2022, and following the Board's approval to increase the company's share repurchase program to up to 10% of the company's public float, Suncor received approval from the TSX to amend its existing NCIB effective as of the close of markets on May 11, 2022, to increase the maximum number of common shares that may be repurchased in the period beginning February 8, 2022, and ending February 7, 2023, from 71,650,000 common shares, or approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2022, to 143,500,000, or approximately 10% of Suncor's public float as at January 31, 2022.

Subsequent to the fourth quarter of 2022, the TSX accepted a notice filed by Suncor to renew its NCIB to purchase the company's common shares through the facilities of the TSX, NYSE and/or alternative trading systems. The notice provides that, beginning February 17, 2023, and ending February 16, 2024, Suncor may purchase for cancellation up to 132,900,000 common shares, which is equal to approximately 10% of Suncor's public float as of February 3, 2023. On February 3, 2023, Suncor had 1,330,006,760 common shares issued and outstanding.

Pursuant to Suncor's previous NCIB, as amended on May 9, 2022, Suncor agreed that it would not purchase more than 143,500,000 common shares between February 8, 2022, and February 7, 2023. Between February 8, 2022, and February 7, 2023, and pursuant to Suncor's previous NCIB (as amended), Suncor repurchased 118,143,500 shares on the open market for approximately $5.248 billion, at a weighted average price of $44.42 per share.

Between February 17, 2023, and March 3, 2023, and pursuant to Suncor's current NCIB (as renewed), Suncor repurchased 2,769,200 shares on the open market, representing the equivalent of 0.2% of its common shares as at February 3, 2023, for $128 million, at a weighted average price of $46.12 per share.

The actual number of common shares that may be repurchased under the NCIB and the timing of any such purchases will be determined by Suncor. Suncor believes that, depending on the trading price of its common shares and other relevant factors, repurchasing its common shares represents an attractive investment opportunity and is in the best interests of the company and its shareholders. The company does not expect that the decision to allocate cash to repurchase shares will affect its long-term strategy.

At December 31 ($ millions, except as noted)	**2022**	2021	2020
Share repurchase activities (thousands of common shares)			
Shares repurchased	**116 908**	83 959	7 527
Share repurchase cost	**5 135**	2 304	307
Weighted average repurchase price per share (dollars per share)	**43.92**	27.45	40.83

Table of Contents

Contractual Obligations, Commitments, Guarantees and Off-Balance Sheet Arrangements

In addition to the enforceable and legally binding obligations in the table below, Suncor has other obligations for goods and services that were entered into in the normal course of business, which may terminate on short notice, including commitments for the purchase of commodities for which an active, highly liquid market exists, and which are expected to be resold shortly after purchase.

The company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources.

In the normal course of business, the company is obligated to make future payments, including contractual obligations and non-cancellable commitments.

	Payment due by period						
($ millions)	2023	2024	2025	2026	2027	Thereafter	Total
Long-term debt[1]	568	568	498	985	556	16 317	**19 492**
Decommissioning and restoration costs[2]	351	397	443	439	440	20 296	**22 366**
Long-term contracts, pipeline capacity and energy services commitments[3]	1 718	1 622	1 469	1 216	1 309	7 678	**15 012**
Exploration work commitments[3]	—	—	53	1	—	486	**540**
Lease obligations[4]	477	420	387	340	312	3 047	**4 983**
Other long-term obligations[5]	5	20	20	20	20	—	**85**
Total	**3 119**	**3 027**	**2 870**	**3 001**	**2 637**	**47 824**	**62 478**

(1) Includes long-term debt and interest payments on long-term debt. Refer to note 21 and note 27 of Suncor's 2022 audited Consolidated Financial Statements.
(2) Represents the undiscounted and uninflated amount of decommissioning and restoration costs. Refer to note 24 of Suncor's 2022 audited Consolidated Financial Statements.
(3) Refer to note 32 of Suncor's 2022 audited Consolidated Financial Statements.
(4) Refer to note 21 and note 27 of Suncor's 2022 audited Consolidated Financial Statements.
(5) Includes Libya EPSA signature bonus and merger consent. Please refer to note 22 of Suncor's 2022 audited Consolidated Financial Statements.

Transactions with Related Parties

The company enters into transactions with related parties in the normal course of business, which includes purchases of feedstock, distribution of refined products, and the sale of refined products and byproducts. These transactions are with joint ventures and associated entities in the company's R&M operations, including pipeline, refined product and petrochemical companies. For more information on these transactions and for a summary of Compensation of Key Management Personnel, refer to note 31 of the 2022 audited Consolidated Financial Statements.

Financial Instruments

The company uses derivative financial instruments, such as physical and financial contracts, to manage certain exposures to fluctuations in interest rates, commodity prices and foreign currency exchange rates as part of its overall risk management program, as well as for trading purposes. For the year ended December 31, 2022, the pre-tax earnings impact of risk management and trading activities was a loss of $187 million (2021 – pre-tax loss of $155 million).

Gains or losses related to derivatives are recorded as Other Income in the Consolidated Statements of Comprehensive Income.

($ millions)	2022	2021
Fair value outstanding, beginning of year	**(98)**	(121)
Cash settlements – paid during the year	**220**	178
Changes in fair value recognized in earnings during the year	**(187)**	(155)
Fair value outstanding, end of year	**(65)**	(98)

The fair value of derivative financial instruments is recorded on the Consolidated Balance Sheets.

Fair value of derivative contracts at December 31 ($ millions)	2022	2021
Accounts receivable	**143**	123
Accounts payable	**(208)**	(221)
	(65)	(98)

Risks Associated with Derivative Financial Instruments

Suncor may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to fulfil their obligations under these contracts. The company minimizes this risk by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties. Suncor's exposure is limited to those counterparties holding derivative contracts with net positive fair values at a reporting date.

Suncor's risk management activities are subject to periodic reviews by management to determine appropriate hedging requirements based on the company's tolerance for exposure to market volatility, as well as the need for stable cash flow to finance future growth. Commodity risk management and trading activities are governed by a separate risk management group that reviews and monitors practices and policies and provides independent verification and valuation of these activities.

For further details on our derivative financial instruments, including assumptions made in the calculation of fair value, a sensitivity analysis of the effect of changes in commodity prices on our derivative financial instruments, and additional discussion of exposure to risks and mitigation activities, refer to note 27 of the company's 2022 audited Consolidated Financial Statements.

Table of Contents

10. Accounting Policies and Critical Accounting Estimates

Suncor's significant accounting policies are described in note 3 of the audited Consolidated Financial Statements for the year ended December 31, 2022.

Adoption of New IFRS Standards

The standards, amendments and interpretations that are adopted up to the date of authorization of the company's consolidated financial statements, and that may have an impact on the disclosures and financial position of the company are disclosed below.

Property, Plant and Equipment: Proceeds before Intended Use

In May 2020, the IASB issued *Property, Plant and Equipment: Proceeds before Intended Use (Amendments to IAS 16)* . The amendments prohibit a company from deducting from the cost of property, plant and equipment revenues received from selling items produced while the company is preparing the asset for its intended use. Instead, a company will recognize such sales proceeds and related costs in profit or loss. The company adopted the amendments prospectively on the effective date January 1, 2022, and there was no impact to the consolidated financial statements as a result of the initial application.

Onerous Contracts – Cost of Fulfilling a Contract

In May 2020, the IASB issued *Onerous Contracts – Cost of Fulfilling a Contract (Amendments to IAS 37).* The amendments specify which costs an entity includes in determining the cost of fulfilling a contract for the purpose of assessing whether the contract is onerous. The company adopted the amendments prospectively on the effective date January 1, 2022, and there was no impact to the consolidated financial statements as a result of the initial application.

Fees in the "10 per cent" Test for Derecognition of Financial Liabilities

In May 2020, the IASB issued *Fees in the "10 per cent" Test for Derecognition of Financial Liabilities (Amendment to IFRS 9).* The amendment clarifies the fees a company includes when assessing whether the terms of a new or modified financial liability are substantially different from the terms of the original financial liability. The company adopted the amendments prospectively on the effective date January 1, 2022, and there was no impact to the consolidated financial statements as a result of the initial application.

Recently Announced Accounting Pronouncements

The standards, amendments and interpretations that are issued, but not yet effective up to the date of authorization of the company's consolidated financial statements, and that may have an impact on the disclosures and financial position of the company are disclosed below. The company intends to adopt these standards, amendments and interpretations when they become effective.

Non-current Liabilities with Covenants

In October 2022, the IASB issued *Non-current Liabilities with Covenants (Amendments to IAS 1).* The amendments improved the information an entity provides when its right to defer settlement of a liability for at least twelve months is subject to compliance with covenants. The amendments are effective January 1, 2024, with early adoption permitted. The company does not anticipate any significant impact from these amendments on the consolidated financial statements as a result of the initial application.

Lease Liability in a Sale and Leaseback

In September 2022, the IASB issued *Lease Liability in a Sale and Leaseback (Amendments to IFRS 16).* The amendments add subsequent measurement requirements for sale and leaseback transactions. The amendments are effective January 1, 2024, with early adoption permitted. The company does not currently have any sale and leaseback transactions and therefore does not anticipate any changes resulting from these amendments on the consolidated financial statements as a result of the initial application.

Significant Accounting Estimates and Judgments

The preparation of financial statements in accordance with IFRS requires management to make estimates and judgments that affect reported assets, liabilities, revenues, expenses, gains, losses and disclosures of contingencies. These estimates and judgments are subject to change based on experience and new information.

Climate Change and Energy Transition

Suncor supports the goals of the Paris Agreement and is committed to achieving the long-term target of net zero GHG emissions by 2050 from its facilities, including those in which it has a working interest. Addressing climate change and providing the secure and reliable energy the world needs requires investment, technological advancement, product innovation, regulatory support and collaborative partnerships, such as the Pathway's Alliance. The rate of change of public policy, consumer behavior, and resulting demand for low carbon options is not certain. Suncor is committed to reducing emissions in our base business, while expanding in complementary low-emissions businesses and working with our customers, governments and partners to realize our shared climate objectives.

Climate change and the transition to a low-emissions economy was considered in preparing the consolidated financial statements, primarily in estimating commodity prices used in impairment and reserves analysis. These may have significant impacts on the currently reported amounts of the company's assets and liabilities discussed below and on similar assets and liabilities that may be recognized in the future. As part of its ongoing business planning, Suncor estimates future costs associated with GHG emissions in its operations and in the evaluation of future projects. The company uses future climate scenarios to test and assess the resilience of its strategy.
The financial statement areas that require significant estimates and judgments are as follows:

Oil and Gas Reserves

The company's estimate of oil and gas reserves is considered in the measurement of depletion, depreciation, impairment, and decommissioning and restoration obligations. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. All reserves have been evaluated at December 31, 2022, by independent qualified reserves evaluators. Oil and gas reserves estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Estimates reflect market and regulatory conditions existing at December 31, 2022, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions, as well as climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels can materially impact the estimation of net reserves. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

Oil and Gas Activities

The company is required to apply judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the costs of these activities shall be expensed or capitalized.

Exploration and Evaluation Costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The company is required to make judgments about future events and circumstances and applies estimates to assess the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop the project. Level of drilling success or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures are important judgments when making this determination. Management uses judgment to determine when these costs are reclassified to Property, Plant and Equipment based on several factors, including the existence of reserves, appropriate approvals from regulatory bodies, joint arrangement partners and the company's internal project approval process.

Determination of Cash Generating Units (CGUs)

A CGU is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and

interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructure and the way in which management monitors the operations.

Asset Impairment and Reversals

Management applies judgment in assessing the existence of impairment and impairment reversal indicators based on various internal and external factors.

The recoverable amount of CGUs and individual assets is determined based on the higher of fair value less costs of disposal or value-in-use calculations. The key estimates the company applies in determining the recoverable amount normally include estimated future commodity prices, discount rates, expected production volumes, future operating and development costs, income taxes and refining margins. In determining the recoverable amount, management may also be required to make judgments regarding the likelihood of occurrence of a future event. Changes to these estimates and judgments will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value. In addition, climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could result in a change in assumptions used in determining the recoverable amount and could affect the carrying value and useful life of the related assets. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of Exploration and Evaluation assets and Property, Plant and Equipment based on estimated future decommissioning and restoration costs. Management applies judgment in assessing the existence and extent as well as the expected method of reclamation of the company's decommissioning and restoration obligations at the end of each reporting period. Management also uses judgment to determine whether the nature of the activities performed is related to decommissioning and restoration activities or normal operating activities.

Actual costs are uncertain and estimates may vary as a result of changes to relevant laws and regulations related to the use of certain technologies, the emergence of new technology, operating experience, prices and closure plans. The estimated timing of future decommissioning and restoration may change due to certain factors, including reserves life. Changes to estimates related to future expected costs, discount rates, inflation assumptions and timing may have a material impact on the amounts presented. In addition, climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could result in a change in assumptions used in determining the carrying value of the liabilities. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

Employee Future Benefits

The company provides benefits to employees, including pensions and other post-retirement benefits. The cost of defined benefit pension plans and other post-retirement benefits received by employees is estimated based on actuarial valuation methods that require professional judgment. Estimates typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, the return on plan assets, mortality rates and future medical costs. Changes to these estimates may have a material impact on the amounts presented.

Other Provisions

The determination of other provisions, including, but not limited to, provisions for royalty disputes, onerous contracts, litigation and constructive obligations, is a complex process that involves judgment about the outcomes of future events, the interpretation of laws and regulations, and estimates on the timing and amount of expected future cash flows and discount rates.

Income Taxes

Management evaluates tax positions, annually or when circumstances require, which involves judgment and could be subject to differing interpretations of applicable tax legislation. The company recognizes a tax provision when a payment to tax authorities is considered probable. However, the results of audits and reassessments and changes in the interpretations of standards may result in changes to those positions and, potentially, a material increase or decrease in the company's assets, liabilities and net earnings.

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's judgment of the likelihood of a future outflow and estimates of the expected settlement amount, timing of reversals, and the tax laws in the jurisdictions in which the company operates.

11. 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 and 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 and electricity prices in the company's upstream business where natural gas and electricity are both inputs and outputs 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 (particularly in emerging markets), market access constraints, regional and international supply and demand imbalances, political developments and government action, decisions by OPEC+ regarding 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, regulatory compliance costs and other local market factors. Natural gas prices in North America are affected by, among other things, supply and demand, inventory levels, weather and 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. 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.

Wide differentials 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.

Commodity prices could be materially and adversely affected by the outbreak of epidemics, pandemics and other public health crises in geographic areas in which Suncor has operations, suppliers, customers or employees, including the COVID-19 pandemic and the ongoing uncertainty as to the extent and duration of the pandemic, as well as uncertainty surrounding new variations or mutations of the COVID-19 virus. Actions that have and may be taken by governmental authorities in response to the ongoing COVID-19 pandemic have resulted, and may continue to result in, a reduction in the demand for, and

prices of, commodities that are closely linked to Suncor's financial performance, including crude oil, refined petroleum products (such as jet fuel and gasoline), natural gas and electricity. Such actions may also increase the risk that storage for crude oil and refined petroleum products could reach capacity in certain geographic locations in which Suncor operates. A prolonged period of decreased demand for, and prices of, these commodities, and any applicable storage constraints, could also result in voluntary curtailment or shutting in production and a decrease in Suncor's refined product volumes and refinery utilization rates.

Carbon Risk

Public support for climate change action and receptivity to alternative or renewable energy technologies has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. There has also been increased activism and public opposition to fossil fuels, and oil sands in particular.

Existing and future laws and regulations in support of a transition to low-carbon energy and climate change action may impose significant constraints on fossil fuel development. Concerns over climate change, fossil fuel extraction, GHG emissions, and water and land-use practices could lead governments to enact additional or more stringent laws and regulations applicable to Suncor and other companies in the energy industry in general, and in the oil sands industry in particular. These risks to the oil sands industry can be offset over time through the commercialization and implementation of low-carbon technologies (e.g., carbon capture, utilization and sequestration) and by increasing growth in low-carbon energies such as hydrogen, renewable fuels and power.

Changes to environmental regulations, including regulations relating to climate change, could impact the demand for the company's products or could require increased capital expenditures, operating expenses, abandonment and reclamation obligations, and distribution costs. These potential added costs may not be recoverable in the marketplace and may result in some current operations or growth projects becoming less profitable or uneconomic. Such regulatory changes could require Suncor to invest further into the development of technologies or other energy products. Such technology development or growth projects could require a significant investment of capital and resources, and any delay in or failure to identify, develop and deploy such technologies or obtain regulatory approvals for these technology projects could prevent Suncor from being able to successfully compete with other companies. More stringent GHG emissions regulations in the jurisdictions in which Suncor operates may also make it difficult for Suncor to compete with companies operating in other jurisdictions with less costly regulations. In addition, legislation or policies that limit the purchase of production from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for Suncor's upstream production and reduce the prices the company receives for its petroleum products, and could result in delayed development, stranded assets or the company being unable to further develop its hydrocarbon resources. The complexity, breadth and velocity of changes in GHG emissions regulations make it difficult to predict the potential impact to Suncor.

Suncor continues to monitor international and domestic efforts to address climate change. While GHG regulations and targets will continue to become more stringent, and while Suncor continues its efforts to reduce its GHG emissions, the absolute operational GHG emissions of the company may rise as a result of growth, mergers and acquisition activities, and changes in the operatorship of assets by Suncor or affiliates. This is particularly relevant in 2022 with Suncor's increase in operated emissions by assuming operatorship of Syncrude in 2021 followed by an increase in equity emissions with Suncor's purchase of 14.65% additional working interest in Fort Hills from Teck, which closed on February 2, 2023. Increases in GHG emissions may impact the profitability of the company's projects, as Suncor will be subject to incremental levies and taxes. There is also a risk that Suncor could face litigation initiated by third parties relating to climate change, including litigation pertaining to GHG emissions, the production, sale, or promotion of fossil fuels and petroleum products, and/or disclosure. For example, the Board of County Commissioners of Boulder County, the Board of County Commissioners of San Miguel County and the City of Boulder, all of Colorado, have brought an action against Suncor and certain of its subsidiaries seeking, among other things, compensation for impacts they allege with respect to climate change. In addition, the mechanics of implementation and enforcement of the *Oil Sands Emissions Limit Act* and the federal government's stated intention to cap and reduce emissions from the oil and gas sector by setting five-year targets to achieve net zero by 2050 are currently under review and it is not yet possible to predict the impact on Suncor. However, such impact could be material.

These developments and future developments could adversely impact the demand for Suncor's products, the ability of Suncor to maintain and grow its production and reserves, and Suncor's reputation, and could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Greenhouse Gas Emissions and Targets

Among other sustainability goals, Suncor's strategic objective is to be a net-zero GHG emissions company by 2050 and the company has set ambitious near-term goals to reduce emissions across its value chain. The company's ability to deliver GHG emissions reductions is subject to numerous risks and uncertainties, and our actions taken to implement these objectives may also expose Suncor to certain additional and/or heightened financial and operational risks.

A reduction in GHG emissions relies on, among other things, Suncor's ability to implement and improve energy efficiency at all of its facilities, future development and growth opportunities, development and deployment of new technologies, ability to sequester and capture carbon, investment in low-carbon power and hydrogen, as well as a transition to low-carbon fuels. In the event that Suncor is unable to implement these strategies and technologies as planned without negatively impacting our expected operations or business plans, or in the event that such strategies or technologies do not perform as expected, Suncor may be unable to meet our GHG targets on the current timelines, or at all.

In addition, achieving the company's GHG emissions reduction targets could require significant capital expenditures and resources, with the potential that the costs required to achieve our target and goals materially differ from our original estimates and expectations, and these differences may be material. In addition, while the intent is to improve efficiency and increase the offering of low-carbon energy, the shift in resources and focus towards emissions reduction could have a negative impact on our operating results. The overall final cost of investing in and implementing an emissions reduction strategy and technologies in furtherance of such strategy, and the resultant change in the deployment of the company's resources and focus, could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Environmental Compliance

Tailings Management and Water Release

Each oil sands mine is required under the Alberta Energy Regulator's (AER) Directive 085 – Fluid Tailings Management for Oil Sands Mining Projects (the Tailings Directive) to seek approval for its updated fluid tailings management plan. If a mine fails to meet a condition of its approved plan, the applicable company could be subject to enforcement actions, including being required to curtail production, and financial consequences, including being subject to a compliance levy or being required to post additional security under the Mine Financial Security Program (MFSP). The full impact of the Tailings Management Framework (TMF), the Tailings Directive and updates to the dam regulations, including the financial consequences of exceeding compliance levels, is not yet fully known, as certain associated policy updates and regulation updates are still under development. Such updates could also restrict the technologies that the company may employ for tailings management and reclamation, which could adversely impact the company's business plans. There could also be risks if the company's tailings management operations fail to operate as anticipated. The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

The five-year review for the TMF may be initiated in 2023, which could result in changes to tailings management requirements. The Alberta government has also been working to develop provincial water release policy guidance which is expected to be completed in 2023. In addition, Environment and Climate Change Canada's work to meet its 2025 timeline for development of the federal Oil Sands Mine Effluent Regulation (OSMER) is progressing. If implemented, OSMER will help enable oil sands companies to return treated mine water to the Athabasca River. Suncor's tailings and reclamation plans are aligned with the current TMF and the OSMER timing and changes to either could result in plan changes.

Suncor supports an integrated water management approach for effective operations, successful reclamation and closure, and positive environmental outcomes. The inability to release treated mine water to the environment continues to result in an increase to both water quality concerns and water containment concerns at Suncor mine sites, which impacts current operations and reclamation and closure planning. Suncor believes that an integrated water management approach to support operations and successful reclamation and closure requires the release of treated oil sands mine water to the environment. The absence of an effective regulatory framework in this area could impact operations and the success and timing of closure and reclamation plans, which could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Alberta's Land-Use Framework

The implementation of, and compliance with, the terms of Alberta's Land-Use Framework through the Lower Athabasca Regional Plan (LARP) may adversely impact Suncor's current properties and projects in northern Alberta due to, among other

things, environmental limits and thresholds. The impact of the LARP on Suncor's operations may be outside of the control of the company, as Suncor's operations could be impacted as a result of restrictions imposed due to the cumulative impact of development by the other operators in the area and not solely in relation to Suncor's direct impact. The uncertainty of changes in Suncor's future development and existing operations required as a result of any future updates or changes to the LARP or its associated frameworks, could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Water Management Regulations

Canada

Suncor currently relies on water obtained under licences and permits from government and regulators in its operating areas. Water licences and permits, like all regulatory approvals, contain conditions to be met in order to maintain compliance with the licence. There can be no assurance that the licences to withdraw and use water will not be rescinded or that additional conditions will not be added. It is also possible that regional water management approaches may require water-sharing agreements between stakeholders. In addition, any changes or expansions of the company's projects may rely on securing licences and permits for additional water withdrawal and use, and there can be no assurance that these licences will be granted in a timely manner or that they will be granted on terms favourable to Suncor. There is also a risk that future laws or changes to existing laws or regulations relating to water access or water management could cause capital expenditures and operating expenses relating to water licence compliance to increase. The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

U.S.

The Commerce City refinery's water discharge permit is currently subject to a renewal process. In late 2021, the Water Division for the Colorado Department of Public Health and Environment (CDPHE) issued a draft water permit that contains new and additional proposed requirements, including with respect to those related to per- and polyfluoroalkyl substances, that could have a material adverse effect on Suncor's business, financial condition and results of operations. Suncor is reviewing the draft permit and will proceed through the permit renewal process.

Biodiversity

Species at risk exist in the areas where Suncor conducts its operations. For example, existing, planned and potential future projects in Alberta are located within the range of woodland caribou, which have been identified as "threatened" under the *Species at Risk Act* (Canada). In response to the Government of Canada's Recovery Strategy for the Woodland Caribou, provincial caribou range plans are being developed through sub-regional planning. The development and implementation of sub-regional plans in these areas may have an impact on the pace and amount of development in these areas and could potentially increase costs due to restoration or offsetting requirements, which could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Pursuant to the Alberta Wetland Policy, future development in wetland areas may be obligated to avoid wetlands or mitigate the development's effects on wetlands. Certain Suncor operations and growth projects where wetlands are regionally abundant will be affected by aspects of the policy where avoidance is not possible and wetland reclamation or replacement may be required, which could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations. Wetland replacement costs are based on wetland value and may be especially high for future oil sands projects and expansions due to the limited opportunity to avoid or minimize impacts to wetlands.

Air and Water Quality Management

A number of Canadian federal, provincial and U.S. federal and state air and water quality regulations and frameworks are in place currently and being developed, changed and/or implemented, which could have an impact on the company's existing operations and planned projects including by, among other things, requiring the company to invest additional capital or incur additional operating and compliance expenses, including, among other things, potentially requiring the company to retrofit equipment to meet new requirements and increase monitoring and mitigation plans. The full impact of these regulations and frameworks is not yet known; however, they could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Market Access

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 oil, 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. In order to secure future market access, financial commitments could be made for projects that do not proceed. 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, 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 poor or substandard 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, prolonged periods of extreme cold or extreme heat, severe winter climate conditions, flooding, droughts and other extreme weather conditions, railcar incidents or derailments, the migration of harmful substances such as, among others, oil spills, gaseous leaks or a release of deleterious substances, loss of tailings dam integrity, pollution and other environmental risks, and accidents, any of which can interrupt operations or cause personal injury or death, or damage to property, equipment (including information technology and related data and controls systems), and the environment.

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 cyberattacks.

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;
- Suncor's E&P offshore operations occur in areas subject to hurricanes and other extreme weather conditions, such as winter storms, pack ice, icebergs and fog. The occurrence of any of these events could result in production shut-ins, the suspension of drilling operations and damage to or destruction of the equipment involved. Harsh weather conditions, particularly in the winter season, may also impact the successful execution of maintenance and startup of operations. Suncor's E&P offshore operations could be indirectly affected by catastrophic events occurring at other

third-party offshore operations, which could give rise to liability, damage to the company's equipment, harm to individuals, force a shutdown of facilities or operations, or result in a shortage of appropriate equipment or specialists required to perform planned operations; and

- Suncor's Refining and Marketing operations are subject to all of the risks normally inherent in the operation of refineries, terminals, pipelines and other distribution facilities and service stations, including, among others, loss of production, slowdowns or shutdowns due to equipment failures, unavailability of feedstock, price and quality of feedstock, or other incidents.

Suncor is also subject to risks relating to the health and safety of its people, as well as the potential for a slowdown or temporary suspension of its operations in locations impacted by an outbreak such as the COVID-19 pandemic. Such a suspension in operations could also be mandated by governmental authorities in response to the COVID-19 pandemic. This could negatively impact Suncor's production or refined product volumes and refinery utilization rates for a sustained period of time, all of which could have a material adverse effect on Suncor's business, financial condition and results of operations.

Although the company maintains a risk management program, which includes an insurance component, such insurance may not provide comprehensive coverage in all circumstances, nor are all such risks insurable. The company self-insures some risks, and the company's insurance coverage does not cover all the costs arising out of the allocation of liabilities and risk of loss arising from Suncor operations.

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

Government/Regulatory Policy

Suncor's businesses operate under federal, provincial, territorial, state and municipal laws in numerous countries. The company is also subject to regulation and intervention by governments in oil and gas industry matters, such as, among others, land tenure; royalties; taxes (including income taxes); government fees; production rates; environmental protection; water; wildlife; fish; air quality; safety performance; the reduction of GHG and other emissions; the export of crude oil, natural gas and other products; interactions with foreign governments; the awarding or acquisition of exploration and production rights, oil sands leases or other interests; the imposition of specific drilling obligations; control over the development, reclamation and abandonment of fields and mine sites; mine financial security requirements; approval of logistics infrastructure; and possibly expropriation or cancellation of contract rights. As part of ongoing operations, the company is also required to comply with a large number of EH&S regulations under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations. Failure to comply with applicable laws and regulations may result in, among other things, the imposition of fines and penalties, production constraints, a compulsory shutdown of facilities or suspension of operations (temporarily or permanently), reputational damage, delays, increased costs, denial of operating and growth permit applications, censure, liability for cleanup costs and damages, and the loss of important licences and permits.

Before proceeding with certain projects, including changes to existing operations, Suncor must obtain various federal, provincial, territorial, state and municipal permits and regulatory approvals, and must also obtain licences to operate certain assets. These processes can involve, among other things, Indigenous and stakeholder consultation, government intervention, environmental impact assessments and public hearings and may be subject to conditions, including security deposit obligations and other commitments. Compliance can also be affected by the loss of skilled staff, inadequate internal processes and compliance auditing.

Failure to obtain, comply with, satisfy the conditions of or maintain regulatory permits, licences and approvals, or failure to obtain them on a timely basis or on satisfactory terms, could result in prosecution, fines, delays, abandonment or restructuring of projects, impacts to production, reputational damage and increased costs, all of which could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations. Suncor's businesses can also be indirectly impacted by a third-party's inability to obtain regulatory approval for a shared infrastructure project or a third-party infrastructure project on which a portion of Suncor's business depends.

Changes in government policy, regulation or other laws, or the interpretation thereof, or the revocation of existing approvals or permits by the government or opposition to Suncor's projects or third-party pipeline and infrastructure projects that delay or prevent necessary permits or regulatory approvals, or which make current operations or growth projects less profitable or uneconomic could materially impact Suncor's operations, existing and planned projects, financial condition, reserves and results of operations.

Digital and Cybersecurity

The efficient operation of Suncor's business is dependent on computer hardware, software and networked systems, including the systems of cloud providers and third parties with which Suncor conducts business. Digital transformation continues to increase the number of, and complexity of, such systems. In the ordinary course of Suncor's business, Suncor collects and stores sensitive data, including intellectual property, proprietary business information and personal information of the company's employees and retail customers. Suncor's operations are also dependent upon a large and complex information framework. Suncor relies on industry-accepted security measures, controls and technology to protect Suncor's information systems and securely maintain confidential and proprietary information stored on the company's information systems, and has adopted a continuous process to identify, assess and manage threats to the company's information systems. While Suncor has an information and cybersecurity program in place, the measures, controls and technology on which the company relies may not be adequate due to the increasing volume, sophistication and rapidly evolving nature of cyber threats. Suncor's information technology and infrastructure, including process control systems, may be vulnerable to attacks by malicious persons or entities motivated by, among others, geopolitical, financial or activist reasons, or breached due to employee error, malfeasance or other disruptions, including natural disasters and acts of war. Although the company maintains a risk management program, which includes an insurance component that may provide coverage for the operational impacts from an attack to, or breach of, Suncor's information technology and infrastructure, including process control systems, the company does not maintain stand-alone cyber insurance. Furthermore, not all cyber risks are insurable. As a result, Suncor's existing insurance may not provide adequate coverage for losses stemming from a cyberattack to, or breach of, its information technology and infrastructure.

Any such attack or breach could compromise Suncor's networks, and the information Suncor stores could be accessed, publicly disclosed, lost, stolen or compromised. Any such attack, breach, access, disclosure or loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, disruptions to Suncor's operations, decreased performance and production, increased costs, damage to Suncor's reputation, physical harm to people or the environment or other negative consequences to Suncor or third parties, which could have a material adverse effect on Suncor's business, financial condition and results of operations.

Competition

The global petroleum industry is highly competitive in many aspects, including the exploration for and the development of new sources of supply, the acquisition of crude oil and natural gas interests, and the refining, distribution and marketing of refined petroleum products. Suncor competes in virtually every aspect of its business with other energy companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. The increasing volatility of the political and social landscape at provincial, federal, territorial, state, municipal and international levels adds complexity.

For Suncor's Oil Sands and E&P businesses, it is difficult to assess the number, level of production and ultimate timing of all potential new projects or when existing production levels may increase. Although increased regulatory requirements have slowed certain larger projects in the short term, an increase in the level of activity may have an impact on regional infrastructure, including pipelines, and could place stress on the availability and cost of all resources required to build and run new and existing oil sands operations.

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

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

Portfolio Development and Execution

There are certain risks associated with the development and execution of Suncor's complex and integrated portfolio of projects and the commissioning and integration of new facilities within its existing asset base.

Portfolio development and execution risk consists of four related primary risks:

- Development – a failure to select the right projects and identify effective scope and solution;
- Engineering – a failure in the specification, design or technology selection;
- Construction – a failure to build the project in the approved time, in accordance with design, and at the agreed cost; and
- Commissioning and startup – a failure of the facility to meet agreed performance targets, including operating costs, efficiency, yield and maintenance costs.

Portfolio development and execution can also be impacted by, among other things, the effect of changing government regulations and public expectations in relation to the impact of oil sands development on the environment, which could significantly impact the company's ability to obtain the necessary environmental and other regulatory approvals; the complexity and diversity of Suncor's portfolio, including joint venture assets; the accuracy of project cost and schedule estimates; the availability and cost of materials, equipment, qualified personnel and logistics infrastructure; maintaining adequate quality management and risks associated with logistics and offshore fabrication, including the cost of materials, and equipment fabricated offshore may be impacted by tariffs, duties and quotas; complexities and risks associated with constructing projects within operating environments and confined construction areas; the commissioning and integration of new facilities within the company's existing asset base could cause delays in achieving guidance, targets and objectives; risks relating to restarting projects placed in safe mode, including increased capital costs; and the impact of weather conditions.

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

Technology Risk

There are risks associated with sustainability, growth and capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations, including that the results of the application of new technologies may differ from simulated, test or pilot environments, or that third-party intellectual property protections may impede the development and implementation of new technology. The success of projects incorporating new technologies cannot be assured. Advantages accrue to companies that can develop and adopt emerging technologies in advance of competitors. The inability to develop, implement and monitor new technologies may impact the company's ability to develop its new or existing operations in a profitable manner or comply with regulatory requirements, which could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Cumulative Impact and Pace of Change

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

Skills, Resource Shortage and Reliance on Key Personnel

The successful operation of Suncor's businesses will depend upon the availability of, and competition for skilled labour and materials supply. There is a risk that the company may have difficulty sourcing and retaining the skilled labour in certain talent segments for current and future operations. Although Suncor has maintained a healthy overall attrition rate over the last decade, Suncor sees acute supply-demand gap potential in some critical talent segments. The labour market is also in flux, which combined with the challenges recruiting to the oil and gas industry and the post-pandemic trend of burnout and employees reassessing their careers, increases the potential risk in attrition and the need for targeted talent remains a risk to be managed. The increasing age of the company's existing workforce, and changing skillset requirements as technology continues to evolve, add further pressure. The availability of competent and skilled contractors for current and future operations is also a risk depending on market conditions. Materials may also be in short supply due to smaller labour forces in many manufacturing operations or due to supply chain disruptions related to the COVID-19 pandemic. Suncor's ability to operate safely and effectively and complete all projects on time and on budget has the potential to be significantly impacted by these risks and this impact could be material.

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

Labour Relations

Hourly employees at Suncor's oil sands facilities (excluding MacKay River and Fort Hills), all of the company's refineries and the majority of the company's terminal and distribution operations and certain of the company's E&P operations are represented by labour unions or employee associations. Approximately 25% of the company's employees were covered by collective agreements at the end of 2022. Negotiations for 13 collective agreements will take place in 2023. Any work interruptions involving the company's employees (including as a result of a strike, lockout or pandemic), contract trades utilized in the company's projects or operations, or any jointly owned facilities operated by another entity present a significant risk to the company and could have a material adverse effect on Suncor's business, financial condition and results of operations.

Joint Arrangement Risk

Suncor has entered into joint arrangements and other contractual arrangements with third parties, including arrangements where other entities operate assets in which Suncor has ownership or other interests and arrangements where Suncor operates assets in which other entities have ownership or other interests. These joint arrangements include, among others, those with respect to Syncrude, Fort Hills, In Situ assets, and operations in Suncor's E&P Canada and E&P International businesses. The success and timing of activities relating to assets and projects operated by others, or developed jointly with others, depend upon a number of factors that are outside of Suncor's control, including, among others, the timing and amount of capital expenditures; the timing and amount of operational and maintenance expenditures; the operator's expertise, financial resources and risk management practices; the approval of other participants; and the selection of technology.

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

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

Financial Risks

Access to Capital

Suncor expects that future capital expenditures will be financed out of cash and cash equivalents balances, cash flow provided by operating activities, available committed credit facilities, issuing commercial paper and, if needed, accessing capital markets. This ability is dependent on, among other factors, commodity prices, the overall state of the capital markets, and financial institutions and investor appetite for investments in the energy industry generally, and the company's securities in particular. In addition, some stakeholders may compare companies based on climate-related performance which can be impacted by numerous factors and perceptions. The company's ability to access capital may also be adversely affected in the event that financial institutions, investors, rating agencies and/or lenders adopt more restrictive decarbonization policies. The COVID-19 pandemic had a significant impact on global capital markets and the availability of liquidity. While access to capital has returned to pre-pandemic levels, the disruption and volatility in global capital markets may reoccur. To the extent that external sources of capital become limited or unavailable or available on unfavourable terms, the ability to make capital investments and maintain existing properties may be constrained.

If the company finances capital expenditures in whole or in part with debt, that may increase its debt levels above industry standards for oil and gas companies of similar size. Depending on future development and growth plans, additional debt

financing may be required that may not be available or, if available, may not be available on favourable terms, including higher interest rates and fees. Neither the Articles of Suncor nor its bylaws limit the amount of indebtedness that may be incurred; however, Suncor is subject to covenants in its existing credit facilities and seeks to avoid an unfavourable cost of debt. The level of the company's indebtedness, and the level of indebtedness relative to the company's ability to generate cash flow, from time to time, could impair its ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise and could negatively affect its credit ratings.

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

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

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

Inflation

The company purchases materials and commodities for use in its business and uses contractors to supplement its workforce in many areas of the organization. Due to the lingering impacts of the COVID-19 pandemic as well as the war in Ukraine and the limited availability of labour, many supply chains have been stretched, resulting in an increase in inflation. While many central banks have increased interest rates in an attempt to reduce inflation, there is no certainty that attempts to control inflation will be successful, or if they are successful, the pace at which inflation may subside.

Even a short period of higher-than-average inflation can lead to structural cost increases in Suncor's business, which may impact its business plans going forward. The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Energy Trading and Risk Management Activities and the Exposure to Counterparties

The nature of Suncor's energy trading and risk management activities, which may make use of derivative financial instruments to manage its exposure to commodity price and other market risks, creates exposure to financial risks, which include, but are not limited to, unfavourable movements in commodity prices, interest rates or foreign exchange that could result in a financial or opportunity loss to the company; a lack of counterparties, due to market conditions or other circumstances that could leave the company unable to liquidate or offset a position, or unable to do so at or near the previous market price; and counterparty default risk.

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

Exchange Rate Fluctuations

The company's 2022 audited Consolidated Financial Statements are presented in Canadian dollars. The majority of Suncor's revenues from the sale of oil and natural gas commodities are based on prices that are determined by, or referenced to, U.S. dollar benchmark prices, while the majority of Suncor's expenditures are realized in Canadian dollars. Suncor also has assets and liabilities, including approximately 60% of the company's debt, that are denominated in U.S. dollars and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. Suncor's financial results, therefore, can be affected significantly by the exchange rates between the Canadian dollar and the U.S. dollar. The company also undertakes operations administered through international subsidiaries, and, therefore, to a lesser extent, Suncor's results can be affected by the exchange rates between the Canadian dollar and the euro and the British pound. These exchange rates may vary substantially and may give rise to favourable or unfavourable foreign currency exposure. A decrease in the value of the

Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of commodities. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease revenues received from the sale of commodities. A decrease in the value of the Canadian dollar relative to the U.S. dollar from the previous balance sheet date increases the amount of Canadian dollars required to settle U.S. dollar denominated obligations. As at December 31, 2022, the Canadian dollar weakened in relation to the U.S. dollar to $0.74 from $0.79 at the start of 2022. Exchange rate fluctuations could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Interest Rate Risk

The company is exposed to fluctuations in short-term Canadian and U.S. interest rates as Suncor maintains a portion of its debt capacity in revolving and floating rate credit facilities and commercial paper, and invests surplus cash in short-term debt instruments and money market instruments, which are off-setting exposures to some degree. Throughout 2022 and so far in 2023, benchmark interest rates have risen in both Canada and the United States. Suncor may also be exposed to higher interest rates when debt instruments are maturing and require refinancing, or when new debt capital needs to be raised. The company is also exposed to changes in interest rates if derivative instruments are used to manage the debt portfolio. Unfavourable changes in interest rates could have a material adverse effect on Suncor's business, financial condition and results of operations.

Royalties and Taxes

Suncor is subject to royalties and taxes imposed by governments in numerous jurisdictions.

Royalties can be impacted by changes in crude oil and natural gas pricing, production volumes, sales volumes, and capital and operating costs, by changes to existing legislation or production sharing contracts; and by results of regulatory audits of prior year filings and other such events. The final determination of these events may have a material impact on the company's royalties expense.

An increase in Suncor's royalties expense, income taxes, property taxes, carbon taxes, levies, tariffs, duties, quotas, border taxes, other taxes and government-imposed compliance costs could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Dividends and Share Repurchases

Suncor's payment of future dividends on its common shares and future share repurchases by Suncor of its common shares will be dependent on, among other things, legislative and stock exchange requirements, the prevailing business environment, the company's financial condition, results of operations, cash flow, the need for funds to finance ongoing operations and growth projects, debt covenants and other business considerations as the company's Board considers relevant. There can be no assurance that Suncor will continue to pay dividends or repurchase shares in the future.

E&P Reserves Replacement

Suncor's future offshore production, and therefore its cash flows and results of operations from E&P, are highly dependent upon success in exploiting its current reserves base and acquiring or discovering additional reserves. Without additions to its E&P reserves through exploration, acquisition or development activities, Suncor's production from its offshore assets will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent Suncor's cash flow is insufficient to fund capital expenditures and external sources of capital become limited or unavailable, Suncor's ability to make the necessary capital investments to maintain and expand its reserves will be impaired. In addition, Suncor may be unable to develop or acquire additional reserves to replace its crude oil and natural gas production at acceptable costs.

Uncertainties Affecting Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the company's control. Suncor's actual production, revenues, royalties, taxes, and development and operating expenditures with respect to the company's reserves will vary from its estimates, and such variances could be material.

Third-Party Service Providers

Suncor's businesses are reliant on the operational integrity of a large number of third-party service providers, including input and output commodity transport (pipelines, rail, trucking, marine) and utilities associated with various Suncor and jointly owned facilities, including electricity. A disruption in service or limited availability by one of these third parties can also have a dramatic impact on Suncor's operations and growth plans. Pipeline constraints that affect takeaway capacity or supply of inputs, such as hydrogen and power, could impact the company's ability to produce at capacity levels. Disruptions in pipeline service could adversely affect commodity prices, Suncor's price realizations, refining operations and sales volumes, or limit the company's ability to produce and deliver production. These interruptions may be caused by the inability of the pipeline to operate or by the oversupply of feedstock into the system that exceeds pipeline capacity. Short-term operational constraints on pipeline systems arising from pipeline interruption and/or increased supply of crude oil have occurred in the past and could occur in the future. There is a risk that third-party outages could impact Suncor's production or price realizations, which could have a material adverse effect on Suncor's business, financial condition and results of operations.

Foreign Operations

The company has operations in a number of countries with different political, economic and social systems. As a result, the company's operations and related assets are subject to a number of risks and other uncertainties arising from foreign government sovereignty over the company's international operations, which may include, among other things, currency restrictions and restrictions on repatriation of funds; loss of revenue, property and equipment as a result of expropriation, nationalization, terrorism, war, insurrection, and geopolitical and other political risks; increases in taxes and government royalties; compliance with existing and emerging anti-corruption laws, including the *Corruption of Foreign Public Officials Act* (Canada), the *Foreign Corrupt Practices Act* (United States), and *Bribery Act* (United Kingdom); renegotiation of contracts with government entities and quasi-government agencies; changes in laws and policies governing operations of foreign-based companies; and economic and legal sanctions (such as restrictions against countries experiencing political violence, or countries that other governments may deem to sponsor terrorism).

If a dispute arises in the company's foreign operations, the company may be subject to the exclusive jurisdiction of foreign courts or may not be able to subject foreign persons to the jurisdiction of a court in Canada or the U.S. In addition, as a result of activities in these areas and a continuing evolution of an international framework for corporate responsibility and accountability for international crimes, there is a risk the company could also be exposed to potential claims for alleged breaches of international or local law.

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

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

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

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact Suncor's personnel, which could result in injury, death, extortion, hostage situations and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or activist incident targeted at a facility or office owned or operated by Suncor could result in the interruption or cessation of key elements of Suncor's operations and may result in property damage. Outcomes of such incidents could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Land Claims and Indigenous Consultation

Indigenous Peoples have claimed Indigenous title and rights to portions of Western Canada. In addition, Indigenous Peoples have filed claims against industry participants relating in part to land claims, which may affect the company's business.

The requirement to consult with Indigenous Peoples in respect of oil and gas projects and related infrastructure has increased in recent years, and the Canadian federal government and the provincial government in Alberta have committed to renew their relationships with the Indigenous Peoples of Canada. In particular, on June 21, 2021, *Canada's United Nations Declaration on the Rights of Indigenous Peoples Act* (the UNDRIP Act) received Royal Assent and came into force. The UNDRIP Act provides a roadmap for the Government of Canada and Indigenous Peoples to work together to implement the United Nations Declaration on the Rights of Indigenous Peoples. Suncor also expressed a desire for the government to clarify the ambiguity around the UNDRIP Act and to provide clear guidelines. It is unknown how the UNDRIP Act will ultimately be implemented and interpreted as a part of Canadian law, and it therefore also remains unclear what its corresponding impact will be on the Crown's duty to consult with and accommodate Indigenous Peoples.

At this point Suncor is unable to assess the effect, if any, that any such land claims, consultation requirements with Indigenous Peoples or the implementation of the UNDRIP Act may have on Suncor's business; however, the impact could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Litigation Risk

There is a risk that Suncor or entities in which it has an interest may be subject to litigation, and claims under such litigation may be material. Various types of claims may be raised in these proceedings, including, but not limited to, environmental damage, climate change and the impacts thereof, breach of contract, common law duties, product liability, antitrust, bribery and other forms of corruption, tax, patent infringement, disclosure, employment matters and in relation to an attack, breach or unauthorized access to Suncor's information technology and infrastructure. Litigation is subject to uncertainty and it is possible that there could be material adverse developments in pending or future cases. Unfavourable outcomes or settlements of litigation could encourage the commencement of additional litigation. Suncor may also be subject to adverse publicity and reputational impacts associated with such matters, regardless of whether Suncor is ultimately found liable. There is a risk that the outcome of such litigation may be materially adverse to the company and/or the company may be required to incur significant expenses or devote significant resources in defence against such litigation, the success of which cannot be guaranteed.

Control Environment

Based on their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Failure to adequately prevent, detect and correct misstatements could have a material adverse effect on how Suncor's business, financial condition and results of operations are reported.

Insurance Coverage

Suncor maintains insurance coverage as part of its risk management program. However, such insurance may not provide comprehensive coverage in all circumstances, nor are all such risks insurable. The company self-insures some risks, and the company's insurance coverage does not cover all the costs arising out of the allocation of liabilities and risk of loss arising from Suncor operations.

Suncor's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead the company to decide to reduce, or possibly eliminate, coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, the company's overall risk exposure could be increased.

Table of Contents

12. Other Items

Control Environment

Based on their evaluation as of December 31, 2022, Suncor's Interim Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States *Securities Exchange Act of 1934*, as amended (the Exchange Act)), are effective to ensure that information required to be disclosed by the company in reports that are filed or submitted to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In April 2022, the company implemented a new enterprise resource planning (ERP) system across the entire organization; accordingly, the company modified a number of internal controls. There were no other changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) that occurred during the period ended December 31, 2022, that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Management will continue to periodically evaluate the company's disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

The company has taken actions and established controls to monitor and maintain appropriate internal controls during the transition period following the new ERP system implementation. These include performing additional controls, verifications and testing to ensure data integrity.

The effectiveness of our internal control over financial reporting as at December 31, 2022, was audited by KPMG LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2022.

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

Corporate Guidance

There have been no changes to the corporate guidance ranges previously issued on February 14, 2023. For further details and advisories regarding Suncor's 2023 corporate guidance, see www.suncor.com/guidance.

Table of Contents

13. Advisories

Non-GAAP and Other Financial Measures

Certain financial measures in this MD&A – namely adjusted operating earnings (loss), adjusted funds from (used in) operations, measures contained in ROCE and ROCE excluding impairments and impairment reversals, price realizations, free funds flow, discretionary free funds flow (deficit), Oil Sands operations cash operating costs, Fort Hills cash operating costs, Syncrude cash operating costs, refining and marketing margin, refining operating expense, net debt, total debt, LIFO inventory valuation methodology and related per share or per barrel amounts or metrics that contain such measures – are not prescribed by GAAP. These non-GAAP financial measures are included because management uses the information to analyze business performance, leverage and liquidity, and it may be useful to investors on the same basis. These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. Except as otherwise indicated, these non-GAAP financial measures are calculated and disclosed on a consistent basis from period to period. Specific adjusting items may only be relevant in certain periods.

Beginning in the fourth quarter of 2021, the company changed the label of operating earnings (loss) and funds from (used in) operations to adjusted operating earnings (loss) and adjusted funds from (used in) operations, respectively, to better distinguish the non-GAAP financial measures from the comparable GAAP measures and better reflect the purpose of the measures. The composition of the measures remains unchanged and therefore no prior periods were revised.

(a) Adjusted Operating Earnings (Loss)

Adjusted operating earnings (loss) is a non-GAAP financial measure that adjusts net earnings (loss) for significant items that are not indicative of operating performance. Management uses adjusted operating earnings (loss) to evaluate operating performance because management believes it provides better comparability between periods. For the years ended December 31, 2022, December 31, 2021, and December 31, 2020, consolidated adjusted operating earnings (loss) are reconciled to net earnings (loss) in the Financial Information section of this MD&A and adjusted operating earnings (loss) for each segment are reconciled to net earnings (loss) in the Segment Results and Analysis section of this MD&A. Adjusted operating earnings (loss) for the three months ended December 31, 2022, and December 31, 2021, are reconciled to net earnings (loss) below.

Beginning in the first quarter of 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated adjusted operating earnings (loss). Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.

(b) Bridge Analyses of Adjusted Operating Earnings (Loss)

Throughout this MD&A, the company presents charts that illustrate the change in adjusted operating earnings (loss) from the comparative period through key variance factors. These factors are analyzed in the Adjusted Operating Earnings (Loss) narratives following the bridge analyses in particular sections of this MD&A. These bridge analyses are presented because management uses this presentation to evaluate performance.

- The factor for Sales Volumes and Mix is calculated based on sales volumes and mix for the Oil Sands and E&P segments and refinery production volumes for the R&M segment.
- The factor for Price, Margin and Other Revenue includes upstream price realizations before royalties, with the exception of Libya, which is net of royalties, and upstream marketing and logistics. Also included are refining and marketing margins, other operating revenue, and the net impacts of sales and purchases of third-party crude, including product purchased for use as diluent in the company's Oil Sands operations and subsequently sold as part of diluted bitumen.
- The factor for Royalties excludes the impact of Libya, as royalties in Libya are taken into account in Price, Margin and Other Revenue as described above.

- The factor for Inventory Valuation includes the impact of the FIFO method of inventory valuation in the company's R&M segment, as well as the impact of the deferral or realization of profit or loss on crude oil sales from the Oil Sands segment to Suncor's refineries, and downstream short-term commodity risk management activities.

- The factor for Operating and Transportation Expense includes project startup costs, operating, selling and general expense, and transportation expense.

- The factor for Financing Expense and Other includes financing expenses, other income, operational foreign exchange gains and losses, and changes in gains and losses on disposal of assets that are not adjusted operating earnings (loss) adjustments.

- The factor for DD&A and Exploration Expense includes depreciation, depletion and amortization expense, and exploration expense.

- The factor for Income Tax includes the company's current and deferred income tax expense on adjusted operating earnings, changes in statutory income tax rates and other income tax adjustments.

(c) Return on Capital Employed (ROCE) and ROCE Excluding Impairments and Impairment Reversals

ROCE is a non-GAAP financial measure that management uses to analyze operating performance and the efficiency of Suncor's capital allocation process. ROCE is calculated using the non-GAAP financial measures adjusted net earnings and average capital employed. Adjusted net earnings is calculated by taking net earnings (loss) and adjusting after-tax amounts for unrealized foreign exchange on U.S. dollar denominated debt and net interest expense. Average capital employed is calculated as a twelve-month average of the capital employed balance at the beginning of the twelve-month period and the month-end capital employed balances throughout the remainder of the twelve-month period. Figures for capital employed at the beginning and end of the twelve-month period are presented to show the changes in the components of the calculation over the twelve-month period.

Year ended December 31 ($ millions, except as noted)		**2022**	2021	2020
Adjustments to net earnings (loss)				
Net earnings (loss)		**9 077**	4 119	(4 319)
Add (deduct) after-tax amounts for:				
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt		**679**	(101)	(286)
Net interest expense		**642**	645	698
Adjusted net earnings (loss) [1]	A	**10 398**	4 663	(3 907)
Capital employed – beginning of twelve-month period				
Net debt[2]		**16 149**	19 814	16 010
Shareholders' equity		**36 614**	35 757	42 042
		52 763	55 571	58 052
Capital employed – end of twelve-month period				
Net debt[2]		**13 639**	16 149	19 814
Shareholders' equity		**39 367**	36 614	35 757
		53 006	52 763	55 571
Average capital employed	B	**53 651**	54 069	56 239
ROCE (%)[3]	A/B	**19.4**	8.6	(6.9)

(1) Total before-tax impact of adjustments is $1.575 billion for the year ended December 31, 2022, $738 million for the year ended December 31, 2021 and $618 million for the year ended December 31, 2020.
(2) Net debt is a non-GAAP financial measure.
(3) ROCE would have been 22.9% for the twelve months ended December 31, 2022, excluding the impact of the impairment reversal of $715 million ($542 million after-tax) and impairment of $70 million ($47 million after-tax) in the second quarter of 2022, and the impact of the impairment of $3.397 billion ($2.586

billion after-tax) in the third quarter of 2022. ROCE would have been 8.2% for the twelve months ended December 31, 2021, excluding the impact of the impairment reversal of $221 million ($168 million after-tax) in the third quarter of 2021. ROCE would have been (2.9%) for the twelve months ended December 31, 2020, excluding the impact of impairments of $559 million ($423 million after-tax) in the fourth quarter of 2020 and $1.821 billion ($1.376 billion after-tax) and $560 million ($422 million after-tax) in the first quarter of 2020.

Table of Contents

(d) Adjusted Funds from (Used in) Operations

Adjusted funds from (used in) operations is a non-GAAP financial measure that adjusts a GAAP measure – cash flow provided by operating activities – for changes in non-cash working capital, which management uses to analyze operating performance and liquidity. Changes to non-cash working capital can be impacted by, among other factors, the timing of offshore feedstock purchases and payments for commodity and income taxes, the timing of cash flows related to accounts receivable and accounts payable, and changes in inventory that management believes reduces comparability between periods.

	Oil Sands			Exploration and Production			Refining and Marketing		
Year ended December 31 ($ millions)	**2022**	2021	2020	**2022**	2021	2020	**2022**	2021	2020
Earnings (loss) before income taxes[1]	**5 633**	2 825	(5 238)	**3 221**	1 791	(1 089)	**5 694**	2 867	1 167
Adjustments for:							**—**	—	
Depreciation, depletion, amortization and impairment	**7 927**	4 585	6 430	**(105)**	324	2 147	**844**	853	867
Accretion	**249**	240	224	**60**	58	48	**8**	6	6
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of financial instruments and trading inventory	**18**	(66)	81	**(6)**	3	(17)	**(50)**	50	44
(Gain) loss on disposal of assets	**(7)**	(4)	(1)	**66**	(227)	—	**(11)**	(19)	(24)
Loss on extinguishment of long-term debt	**—**	—	—	**—**	—	—	**—**	—	—
Share-based compensation	**139**	61	(59)	**6**	5	(9)	**50**	34	(36)
Exploration	**—**	—	—	**—**	—	80	**—**	—	—
Settlement of decommissioning and restoration liabilities	**(264)**	(245)	(212)	**(21)**	(1)	(7)	**(23)**	(17)	(12)
Other	**136**	179	116	**(43)**	(2)	(35)	**49**	57	21
Current income tax expense	—	—	—	—	—	—	—	—	—
Adjusted funds from (used in) operations[1]	**13 831**	7 575	1 341	**3 178**	1 951	1 118	**6 561**	3 831	2 033
Change in non-cash working capital									
Cash flow provided by operating activities									

	Corporate and Eliminations			Income Taxes[1]			Total		
Year ended December 31 ($ millions)	**2022**	2021	2020	**2022**	2021	2020	**2022**	2021	2020
Earnings (loss) before income taxes[1]	**(2 232)**	(1 913)	(937)	**—**	—	—	**12 316**	5 570	(6 097)
Adjustments for:									
Depreciation, depletion, amortization and impairment	**120**	88	82	**—**	—	—	**8 786**	5 850	9 526
Accretion	**(1)**	—	—	**—**	—	—	**316**	304	278
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**729**	(113)	(312)	**—**	—	—	**729**	(113)	(312)
Change in fair value of financial instruments and trading inventory	**—**	—	—	**—**	—	—	**(38)**	(13)	108
(Gain) loss on disposal of assets	**(3)**	(7)	9	**—**	—	—	**45**	(257)	(16)
Loss on extinguishment of long-term debt	**32**	80	—	**—**	—	—	**32**	80	—
Share-based compensation	**133**	105	(134)	**—**	—	—	**328**	205	(238)
Exploration	**—**	—	—	**—**	—	—	**—**	—	80
Settlement of decommissioning and restoration liabilities	**(6)**	—	—	**—**	—	—	**(314)**	(263)	(231)
Other	**(12)**	55	17	**—**	—	—	**130**	289	119
Current income tax expense	**—**	—	—	**(4 229)**	(1 395)	659	**(4 229)**	(1 395)	659
Adjusted funds from (used in) operations[1]	**(1 240)**	(1 705)	(1 275)	**(4 229)**	(1 395)	659	**18 101**	10 257	3 876
Change in in non-cash working capital							**(2 421)**	1 507	(1 201)

Cash flow provided by operating activities	**15 680**	11 764	2 675

(1) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated adjusted funds from (used in) operations. Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.

(e) Free Funds Flow and Discretionary Free Funds Flow (Deficit)

Free funds flow is a non-GAAP financial measure that is calculated by taking adjusted funds from operations and subtracting capital expenditures, including capitalized interest. Free funds flow reflects cash available for increasing distributions to shareholders and reducing debt. Management uses free funds flow to measure the capacity of the company to increase returns to shareholders and to grow Suncor's business.

($ millions)	**2022**	2021	2020
Cash flow provided by operating activities	**15 680**	11 764	2 675
Deduct (add) change in non-cash working capital	**(2 421)**	1 507	(1 201)
Adjusted funds from operations	**18 101**	10 257	3 876
Less capital expenditures including capitalized interest[(1)]	**(4 987)**	(4 555)	(3 926)
Free funds flow (deficit)	**13 114**	5 702	(50)

(1) Excludes capital expenditures related to assets held for sale of $133 million in 2022.

(f) Oil Sands Operations, Fort Hills and Syncrude Cash Operating Costs

Cash operating costs are calculated by adjusting Oil Sands segment OS&G expense for i) non-production costs that management believes do not relate to production performance, including, but not limited to, share-based compensation adjustments, research costs, safe-mode costs associated with the deferral of capital projects, additional costs incurred in response to the COVID-19 pandemic, adjustments to reflect the cost of internal transfers in the receiving asset at the cost of production and the expense recorded as part of a non-monetary arrangement involving a third-party processor; ii) revenues associated with excess capacity, including excess power generated and sold that is recorded in operating revenue; and iii) project startup costs. Non-production costs in 2020 also include the relief provided under the CEWS program. Oil Sands operations and Syncrude production volumes are gross of internally consumed diesel and feedstock transfers between assets through the interconnecting pipelines. Oil Sands operations, Fort Hills and Syncrude cash operating costs are reconciled in the Segment Results and Analysis – Oil Sands section of this document. Management uses cash operating costs to measure operating performance.

(g) Refining and Marketing Gross Margin and Refining Operating Expense

Refining and marketing gross margins and refining operating expense are non-GAAP financial measures. Refining and marketing gross margin, on a FIFO basis, is calculated by adjusting R&M segment operating revenue, other income and purchases of crude oil and products (all of which are GAAP measures) for intersegment marketing fees recorded in intersegment revenues and the impact of inventory write-downs recorded in purchases of crude oil and products. Refining and marketing gross margin, on a LIFO basis, is further adjusted for the impacts of FIFO inventory valuation recorded in purchases of crude oil and products and short-term risk management activities recorded in other income (loss). Refinery operating expense is calculated by adjusting R&M segment OS&G for i) non-refining costs pertaining to the company's supply, marketing and ethanol businesses; and ii) non-refining costs that management believes do not relate to the production of refined products, including, but not limited to, share-based compensation, enterprise shared service allocations and CEWS in 2020. Management uses refining and marketing gross margin and refining operating expense to measure operating performance on a production barrel basis.

Year ended December 31 ($ millions, except as noted)	**2022**	2021	2020
Refining and marketing gross margin reconciliation			
Operating revenues	**36 728**	22 915	15 272
Purchases of crude oil and products	**(27 261)**	(16 807)	(11 243)
	9 467	6 108	4 029
Other (loss) income	**(60)**	(50)	48
Non-refining and marketing margin	**(20)**	(54)	(57)
Refining and marketing gross margin – FIFO	**9 387**	6 004	4 020
Refinery production[(1)] (mbbls)	**168 149**	162 862	158 991
Refining and marketing gross margin – FIFO ($/bbl)	**55.85**	36.85	25.30
FIFO and risk management activities adjustment	**(230)**	(972)	532
Refining and marketing gross margin – LIFO	**9 157**	5 032	4 552
Refining and marketing gross margin – LIFO ($/bbl)	**54.45**	30.90	28.65
Refining operating expense reconciliation			
Operating, selling and general expense	**2 427**	2 019	1 759
Non-refining costs	**(1 246)**	(1 051)	(885)
Refining operating expense	**1 181**	968	874
Refinery production[(1)]	**168 149**	162 862	158 991
Refining operating expense ($/bbl)	**7.00**	5.95	5.50

(1) Refinery production is the output of the refining process, and differs from crude oil processed as a result of volumetric adjustments for non-crude feedstock, volumetric gain associated with the refining process, and changes in unfinished product inventories.

(h) Impact of First-in, First-out (FIFO) Inventory Valuation on Refining and Marketing Net Earnings

GAAP requires the use of a FIFO inventory valuation methodology. For Suncor, this results in a disconnect between the sales prices for refined products, which reflect current market conditions, and the amount recorded as the cost of sale for the related refinery feedstock, which reflects market conditions at the time when the feedstock was purchased. This lag between purchase and sale can be anywhere from several weeks to several months, and is influenced by the time to receive crude after purchase (which can be several weeks for foreign offshore crude purchases), regional crude inventory levels, the completion of refining processes, transportation time to distribution channels and regional refined product inventory levels.

Suncor prepares and presents an estimate of the impact of using a FIFO inventory valuation methodology compared to a LIFO methodology, because management uses the information to analyze operating performance and compare itself against refining peers that are permitted to use LIFO inventory valuation under United States GAAP (U.S. GAAP).

The company's estimate is not derived from a standardized calculation and, therefore, may not be directly comparable to similar measures presented by other companies, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP or U.S. GAAP.

(i) Net Debt and Total Debt

Net debt and total debt are non-GAAP financial measures that management uses to analyze the financial condition of the company. Total debt includes short-term debt, current portion of long-term debt, current portion of long-term lease liabilities, long-term debt and long-term lease liabilities (all of which are GAAP measures). Net debt is equal to total debt less cash and cash equivalents (a GAAP measure).

At December 31 ($ millions, except as noted)	**2022**	2021	2020
Short-term debt	**2 807**	1 284	3 566
Current portion of long-term debt	**—**	231	1 413
Current portion of long-term lease liabilities	**317**	310	272
Long-term debt	**9 800**	13 989	13 812
Long-term lease liabilities	**2 695**	2 540	2 636
Total debt	**15 619**	18 354	21 699
Less: Cash and cash equivalents	**1 980**	2 205	1 885
Net debt	**13 639**	16 149	19 814
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**729**	(113)	(312)
Net debt excluding foreign exchange impacts	**12 910**	16 262	20 126
Shareholders' equity	**39 367**	36 614	35 757
Total debt plus shareholders' equity	**54 986**	54 968	57 456
Total debt to total debt plus shareholders' equity (%)	**28.4**	33.4	37.8
Net debt to net debt plus shareholders' equity (%)	**25.7**	30.6	35.7
Net debt to net debt plus shareholders' equity – excluding leases (%)	**21.3**	26.6	32.1

(j) Price Realizations

Price realizations are a non-GAAP measure used by management to measure profitability. Oil Sands price realizations are presented on a crude product basis and are derived from the Oil Sands segmented statement of net earnings (loss), after adjusting for items not directly attributable to the revenues associated with production. E&P price realizations are presented on an asset location basis and are derived from the E&P segmented statement of net earnings (loss), after adjusting for other E&P assets, such as Libya, for which price realizations are not provided.

Oil Sands Price Realizations

For the year ended	**December 31, 2022**				December 31, 2021			
($ millions, except as noted)	**Non-Upgraded Bitumen**	**Upgraded – Net SCO and Diesel**	**Crude Sales Basket**	**Oil Sands Segment**	Non-Upgraded Bitumen	Upgraded – Net SCO and Diesel	Crude Sales Basket	Oil Sands Segment
Operating revenues, net of royalties	**6 980**	**19 488**	**26 468**	**26 468**	5 092	13 305	18 397	18 397
Add: Royalties	**912**	**3 051**	**3 963**	**3 963**	376	1 147	1 523	1 523
Operating revenues	**7 892**	**22 539**	**30 431**	**30 431**	5 468	14 452	19 920	19 920
Other (loss) income	**(80)**	**27**	**(53)**	**(53)**	(56)	62	6	6
Purchases of crude oil and products	**(1 673)**	**(377)**	**(2 050)**	**(2 050)**	(1 231)	(213)	(1 444)	(1 444)
Gross realization adjustment[1]	**(119)**	**(420)**	**(539)**		(210)	(325)	(535)	
Gross realizations	**6 020**	**21 769**	**27 789**		3 971	13 976	17 947	
Transportation and distribution	**(438)**	**(772)**	**(1 210)**	**(1 210)**	(359)	(767)	(1 126)	(1 126)
Price realization	**5 582**	**20 997**	**26 579**		3 612	13 209	16 821	
Sales volumes (mbbls)	**65 960**	**176 632**	**242 592**		67 094	169 983	237 077	
Price realization per barrel	**84.63**	**118.88**	**109.57**		53.80	77.73	70.96	

For the year ended	December 31, 2020			
($ millions, except as noted)	Non-Upgraded Bitumen	Upgraded – Net SCO and Diesel	Crude Sales Basket	Oil Sands Segment
Operating revenues, net of royalties	2 024	8 498	10 522	10 522
Add: Royalties	19	76	95	95
Operating revenues	2 043	8 574	10 617	10 617
Other (loss) income	21	277	298	298
Purchases of crude oil and products	(702)	(142)	(844)	(844)
Gross realization adjustment[1]	(54)	(458)	(512)	
Gross realizations	1 308	8 251	9 559	
Transportation and distribution	(476)	(747)	(1 223)	(1 223)
Transportation and distribution adjustment[2]	197	—	197	
Net transportation and distribution	(279)	(747)	(1 026)	
Price realization	1 029	7 504	8 533	
Sales volumes (mbbls)	45 980	171 211	217 191	
Price realization per barrel	22.37	43.83	39.29	

(1) Reflects the items not directly attributed to revenues received from the sale of proprietary crude and net non-proprietary activity at its deemed point of sale.
(2) Reflects adjustments for expenses or credits not directly related to the transportation of the crude product to its deemed point of sale.

E&P Price Realizations

For the year ended	December 31, 2022				December 31, 2021			
($ millions, except as noted)	**E&P International**	**E&P Canada**	**Other(1)**	**E&P Segment**	E&P International	E&P Canada	Other(1)	E&P Segment
Operating revenues, net of royalties	**1 222**	**2 122**	**379**	**3 723**	815	1 447	238	2 500
Add: Royalties	**—**	**342**	**266**	**608**	—	237	241	478
Operating revenues	**1 222**	**2 464**	**645**	**4 331**	815	1 684	479	2 978
Transportation and distribution	**(24)**	**(61)**	**(16)**	**(101)**	(25)	(44)	(43)	(112)
Price realization	**1 198**	**2 403**	**629**		790	1 640	436	
Sales volumes (mbbls)	**9 453**	**18 753**			9 616	19 386		
Price realization per barrel	**126.61**	**128.07**			82.16	84.70		

For the year ended	December 31, 2020			
($ millions, except as noted)	E&P International	E&P Canada	Other(1)	E&P Segment
Operating revenues, net of royalties	809	1 058	(111)	1 756
Add: Royalties	—	94	49	143
Operating revenues	809	1 152	(62)	1 899
Transportation and distribution	(34)	(65)	(1)	(100)
Price realization	775	1 087	(63)	
Sales volumes (mbbls)	15 406	21 879		
Price realization per barrel	50.28	49.69		

(1) Reflects other E&P assets, such as Libya, for which price realizations are not provided.

(k) Adjusted Operating Earnings (Loss)(1) Reconciliations – Fourth Quarter 2022 and 2021

For the quarter ended December 31			Exploration and		Refining and		Corporate					
($ millions)	Oil Sands		Production		Marketing		and Eliminations		Income Taxes(1)		Total	
	2022	2021	**2022**	2021	**2022**	2021	**2022**	2021			**2022**	2021
Net earnings (loss)(1)	**1 625**	1 169	**578**	603	**1 517**	599	**(182)**	(317)	**(797)**	(501)	**2 741**	1 553
Unrealized foreign exchange gain on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**(200)**	(25)	**—**	—	**(200)**	(25)
Unrealized loss (gain) on risk management activities	**94**	3	**—**	—	**12**	(17)	**—**	—	**—**	—	**106**	(14)
Gain on significant disposal(2)	**—**	—	**—**	(227)	**—**	—	**—**	—	**—**	—	**—**	(227)
Income tax (recovery) expense excluded from adjusted operating earnings(3)	**—**	—	**—**	—	**—**	—	**—**	—	**(215)**	7	**(215)**	7
Adjusted operating earnings (loss)(1)	**1 719**	1 172	**578**	376	**1 529**	582	**(382)**	(342)	**(1 012)**	(494)	**2 432**	1 294

(1) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated adjusted operating earnings (loss). Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.

(2) During the fourth quarter of 2021, the company recorded a gain of $227 million before-tax on the sale of the company's interest in the Golden Eagle Area Development, in the E&P segment.

(3) In the fourth quarter of 2022, income tax (recovery) expense excluded from adjusted operating earnings includes a deferred income tax recovery of $171 million related to the anticipated sale of the company's U.K. E&P portfolio and a current income tax recovery of $39 million related to the sale of its wind and solar assets.

Table of Contents

(I) Adjusted Funds from Operations Reconciliations – Fourth Quarter 2022 and 2021

For the quarter ended December 31 ($ millions)	Oil Sands		Exploration and Production		Refining and Marketing		Corporate and Eliminations		Income Taxes(1)		Total	
	2022	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Earnings (loss) before income taxes(1)	**1 625**	1 169	**578**	603	**1 517**	599	**(182)**	(317)	**—**	—	**3 538**	2 054
Adjustments for:												
Depreciation, depletion, amortization and impairment	**1 080**	1 237	**130**	129	**226**	243	**29**	21	**—**	—	**1 465**	1 630
Accretion	**64**	61	**15**	15	**2**	1	**—**	—	**—**	—	**81**	77
Unrealized foreign exchange gain on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**(200)**	(25)	**—**	—	**(200)**	(25)
Change in fair value of financial instruments and trading inventory	**105**	8	**(11)**	42	**(121)**	—	**—**	—	**—**	—	**(27)**	50
(Gain) loss on disposal of assets	**(5)**	(4)	**1**	(227)	**(1)**	(1)	**(3)**	—	**—**	—	**(8)**	(232)
Loss on extinguishment of long-term debt	**—**	—	**—**	—	**—**	—	**32**	—	**—**	—	**32**	—
Share-based compensation	**66**	36	**5**	4	**30**	21	**66**	64	**—**	—	**167**	125
Settlement of decommissioning and restoration liabilities	**(61)**	(71)	**(2)**	1	**(11)**	(6)	**(5)**	—	**—**	—	**(79)**	(76)
Other	**55**	23	**3**	(2)	**21**	12	**(10)**	5	**—**	—	**69**	38
Current income tax expense	**—**	—	**—**	—	**—**	—	**—**	—	**(849)**	(497)	**(849)**	(497)
Adjusted funds from (used in) operations(1)	**2 929**	2 459	**719**	565	**1 663**	869	**(273)**	(252)	**(849)**	(497)	**4 189**	3 144
Change in non-cash working capital											**(265)**	(529)
Cash flow provided by operating activities											**3 924**	2 615

(1) Beginning in 2022, to align with how management evaluates segment performance, the company revised its segment presentation to reflect segment results before income tax expense and present tax at a consolidated level. This presentation change has no effect on consolidated adjusted funds from (used in) operations. Comparative periods have been revised to reflect this change. See the Income Tax section of this MD&A for a discussion on income taxes.

Table of Contents

Measurement Conversions

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

Common Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

Measurement

bbl	barrel
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcf/d	millions of cubic feet of natural gas per day
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
m^3	cubic metres
MW	megawatts
MWh	megawatt hour

Places and Currencies

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

Financial and Business Environment

DD&A	Depreciation, depletion and amortization
WTI	West Texas Intermediate
WCS	Western Canadian Select
SCO	Synthetic crude oil
SYN	Synthetic crude oil benchmark
MSW	Mixed Sweet Blend
NYMEX	New York Mercantile Exchange

Table of Contents

Forward-Looking Information

This MD&A contains certain forward-looking statements and forward-looking information (collectively, forward-looking statements) within the meaning of applicable Canadian and U.S. securities laws and other information based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of information available at the time the statement was made and consider Suncor's experience and its perception of historical trends, including expectations and assumptions concerning: the accuracy of reserves estimates; the current and potential adverse impacts of the COVID-19 pandemic, including the status of the pandemic and future waves; commodity prices and interest and foreign exchange rates; the performance of assets and equipment; capital efficiencies and cost savings; applicable laws and government policies; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour, services and infrastructure; the satisfaction by third parties of their obligations to Suncor; the development and execution of projects; and the receipt, in a timely manner, of regulatory and third-party approvals. All statements and information that address expectations or projections about the future, and statements and information about Suncor's strategy for growth, expected and future expenditures or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and the expected impact of future commitments are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects", "anticipates", "will", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", "continue", "should", "may", "potential", "future", "opportunity", "would", "priority" and similar expressions.

Forward-looking statements in this MD&A include references to:

- *Suncor's strategy, including its priority to deliver competitive and sustainable returns to shareholders and its aim to maximize shareholder returns, its plans on how to achieve this strategy, its belief that its commitment to capital discipline, its balance sheet strength and financial health provide the foundation for its capital allocation framework by supporting long-term value creation and increasing returns to shareholders, and Suncor's belief that it is well positioned to execute on its strategies and priorities due to the company's competitive advantages: its unique, physically integrated portfolio with scale and strength; its regional oil sands advantage, including an industry-leading long-life, low-decline oil sands reserves base; an offshore business that provides geographically diversified cash flow; a highly efficient, tightly integrated downstream business supported by competitive sales channels; and its investment in sustainability, technology and innovation;*
- *Suncor's belief that the acquisition of an additional working interest in Fort Hills will meet Suncor's return objectives and build upon the company's strategy to optimize its portfolio around its core assets;*
- *expectations regarding the sale of the company's U.K. assets, including that a sale is anticipated to close in mid-2023;*
- *expectations about the West White Rose Project, including the expectation that it will extend the life of the existing White Rose assets and the expectation that production will commence in the first half of 2026 and will extend the production life of the White Rose field, providing long-term value for the company;*
- *expectations about Terra Nova and the ALE Project, including the expectation that the ALE Project will extend the production life of the Terra Nova field by approximately 10 years and provide many benefits to the Newfoundland and Labrador and Canadian economies in the form of taxes, royalties and employment and that the FPSO will return to production in the second quarter of 2023;*
- *Suncor's strategy and the key components of its strategy including its intent to optimize value through integration and secured market access, optimize asset portfolio, drive value through high-return investments, maximize value through operational excellence and reliability, be an industry leader in sustainable development and global energy expansion and be technology and people enabled, as well as the expected benefits of such strategies and the plans the company expects to take in progressing such strategies;*
- *statements about Suncor's strategic objective to be a net-zero GHG emissions company by 2050 and its near-term GHG emissions reduction goal, including Suncor's aim to substantially contribute to society's net-zero goals by reducing emissions across its base business, growing its low-emissions energy business and working with others to reduce emissions;*
- *Suncor's belief that its investments in the energy expansion will complement its existing core capabilities: increasing its low-carbon power generation, expanding into clean hydrogen production and growing its existing renewable liquid*

fuels business, and that unleashing the full potential of its people and technology will be critical in achieving its environmental, operational and financial goals;

- *statements regarding the Pathways Alliance, including its aims, expectations regarding timing and the expected pathways the alliance will take to address GHG emissions;*
- *the aim, objectives and potential benefits of Suncor's clean energy investments, including Enerkem Inc., LanzaJet, Inc., Svante Inc. and the Varennes Carbon Recycling facility, and Suncor's belief that these investments complement its existing product mix and demonstrate Suncor's involvement in the evolving global energy expansion and are key to Suncor's GHG emissions reduction objective;*
- *Suncor's expectations for the coke-fired boiler replacement project, including the expectation that the cogeneration units will provide reliable steam generation required for Suncor's extraction and upgrading operations to generate electricity that will be transmitted to Alberta's power grid and provide a lower-carbon power alternative while delivering value to Suncor and the expectation that it will be in-service in late 2024;*
- *expectations for Suncor's partnership with ATCO Ltd. on a potential world-scale clean hydrogen project, including the expected benefits and timing estimates;*
- *expectations for the Oil Sands segment, including the potential development opportunities that may support future mining operations (Base Mine Extension and Audet) or in situ production (including Meadow Creek, Lewis, OSLO, Gregoire, Chard and Kirby), the company's intention to continue to leverage its regional advantage through the continued coordination of maintenance across its assets, leveraging economies of scale and utilizing the connectivity of its assets and to progress opportunities to further increase the integration and flexibility of its regional assets; the company's safety plans and the areas of focus of such plans and the steps it is planning on implementing in 2023; the intended focus for cost management in 2023 and expectations for the company's three-year mine improvement plan at Fort Hills and the impacts thereof ;*
- *the expectation that the Mildred Lake Extension project will sustain Syncrude's current production levels by extending the life of the North Mine using existing extraction and upgrading facilities while minimizing the environmental impacts of building infrastructure and that the project will come online in late 2025;*
- *expectations for the E&P segment, including that the segment will continue to focus on strategic production growth of its East Coast E&P assets, with ongoing development activities intended to leverage existing facilities and infrastructure to provide incremental production and extend the productive life of existing fields and that these development activities are planned to continue in 2023, including development drilling at Hebron and Hibernia;*
- *expectations for the R&M segment, including that the company will continue to optimize the Petro-Canada™ retail business with the goal of further strengthening Suncor's integrated R&M business and driving increased long-term value for shareholders and the steps Suncor will take to enhance its retail business, as well as expected economic investment spending and sustaining capital in 2023;*
- *Suncor's expectation that it will remain disciplined in the execution of its capital allocation framework and increase its share buyback allocation to 75% by the end of the first quarter of 2023 while continuing to progress towards its net debt reduction targets in 2023;*
- *Suncor's expectation that it will continue to deliver on the free funds flow initiatives it has previously communicated, such as the cogeneration facility and Oil Sands Base, autonomous haul systems, and tailings initiatives;*
- *the expectation that the Commerce City refinery will return to normal production rates by the end of the first quarter; and*
- *the expectation that well pads under construction will maintain existing production levels at Firebag and MacKay River in future years as production from existing well pads declines.*

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

- *planned turnaround activities at Syncrude and Oil Sands Base Upgrader 2 and the first full plant turnaround at Fort Hills; and*

- *planned maintenance at the Sarnia and Edmonton refineries.*

Also:

- *economic sensitivities;*
- *Suncor's belief that its indicative 5-2-2-1 index will continue to be an appropriate measure against Suncor's actual results;*
- *the company's priority regarding returning value to shareholders and strengthening the balance sheet, and the company's ongoing ability to generate cash flow and commitment to return cash to shareholders;*
- *statements about Suncor's share repurchase program, including its belief that, depending on the trading price of its common shares and other relevant factors, purchasing its own shares represents an attractive investment opportunity and is in the best interests of the company and its shareholders, and Suncor's expectation that the decision to allocate cash to repurchase shares will not affect its long-term strategy;*
- *the company's belief that it does not have any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources;*
- *Suncor's planned 2023 capital spending program of $5.4 billion to $5.8 billion and the belief that the company will have the capital resources to fund its planned 2021 capital spending program and to meet current and future working capital requirements through cash and cash equivalents balances, cash flow provided by operating activities, available committed credit facilities, issuing commercial paper and, if needed, accessing capital markets;*
- *Suncor's expectations as to how its 2023 capital expenditures will be directed and the expected benefits therefrom;*
- *the objectives of the company's short-term investment portfolio and the expectation that the maximum weighted average term to maturity of the company's short-term investment portfolio will not exceed six months, and all investments will be with counterparties with investment grade debt ratings;*
- *management of debt levels continuing to be a priority for Suncor given the company's long-term growth plans and future expected volatility in the commodity pricing environment, and Suncor's belief that a phased and flexible approach to existing and future projects should assist Suncor in maintaining its ability to manage project costs and debt levels;*
- *Suncor's intention to adopt certain accounting standards, amendments and interpretations when they become effective; and*
- *expectations with respect to changes to law and government policy.*

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

The financial and operating performance of the company's reportable operating segments, specifically Oil Sands, E&P and R&M, may be affected by a number of factors.

Factors that affect Suncor's Oil Sands segment include, but are not limited to, volatility in the prices for crude oil and other production, and the related impacts of fluctuating light/heavy and sweet/sour crude oil differentials; changes in the demand for refinery feedstock and diesel fuel, including the possibility that refiners that process the company's proprietary production will be closed, experience equipment failure or other accidents; Suncor's ability to operate its Oil Sands facilities reliably in order to meet production targets; the output of newly commissioned facilities, the performance of which may be difficult to predict during initial operations; Suncor's dependence on pipeline capacity and other logistical constraints, which may affect the company's ability to distribute products to market; Suncor's ability to finance Oil Sands growth and sustaining capital expenditures; the availability of bitumen feedstock for upgrading operations, which can be negatively affected by poor ore

grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage, and in situ reservoir and equipment performance, or the unavailability of third-party bitumen; changes in operating costs, including the cost of labour, natural gas and other energy sources used in oil sands processes; and the company's ability to complete projects, including planned maintenance events, both on time and on budget, which could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Alberta's Wood Buffalo region and the surrounding area (including housing, roads and schools).

Factors that affect Suncor's E&P segment include, but are not limited to, volatility in crude oil and natural gas prices; operational risks and uncertainties associated with oil and gas activities, including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, and pollution and other environmental risks; adverse weather conditions, which could disrupt output from producing assets or impact drilling programs, resulting in increased costs and/or delays in bringing on new production; political, economic and socio-economic risks associated with Suncor's foreign operations, including the unpredictability of operating in Libya due to ongoing political unrest; and market demand for mineral rights and producing properties, potentially leading to losses on disposition or increased property acquisition costs.

Factors that affect Suncor's R&M segment include, but are not limited to, fluctuations in demand and supply for refined products that impact the company's margins; market competition, including potential new market entrants; the company's ability to reliably operate refining and marketing facilities in order to meet production or sales targets; and risks and uncertainties affecting construction or planned maintenance schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.

Additional risks, uncertainties and other factors that could influence the financial and operating performance of all of Suncor's operating segments and activities include, but are not limited to, changes in general economic, market and business conditions, such as commodity prices, interest rates and currency exchange rates (including as a result of demand and supply effects resulting from the COVID-19 pandemic and the actions of OPEC+); fluctuations in supply and demand for Suncor's products; the successful and timely implementation of capital projects, including growth projects and regulatory projects; risks associated with the development and execution of Suncor's projects and the commissioning and integration of new facilities; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; the risk that projects and initiatives intended to achieve cash flow growth and/or reductions in operating costs may not achieve the expected results in the time anticipated or at all; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; actions by government authorities, including the imposition or reassessment of, or changes to, taxes, fees, royalties, duties and other government-imposed compliance costs, and mandatory production curtailment orders and changes thereto; changes to laws and government policies that could impact the company's business, including environmental (including climate change), royalty and tax laws and policies; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to the company; the unavailability of, or outages to, third-party infrastructure that could cause disruptions to production or prevent the company from being able to transport its products; the occurrence of a protracted operational outage, a major safety or environmental incident, or unexpected events such as fires (including forest fires), equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; the potential for security breaches of Suncor's information technology and infrastructure by malicious persons or entities, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; security threats and terrorist or activist activities; the risk that competing business objectives may exceed Suncor's capacity to adopt and implement change; risks and uncertainties associated with obtaining regulatory, third-party and stakeholder approvals outside of Suncor's control for the company's operations, projects, initiatives, and exploration and development activities and the satisfaction of any conditions to approvals; the potential for disruptions to operations and construction projects as a result of Suncor's relationships with labour unions that represent employees at the company's facilities; the company's ability to find new oil and gas reserves that can be developed economically; the accuracy of Suncor's reserves, resources and future production estimates; market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates or to issue other securities at acceptable prices; maintaining an optimal debt to cash flow ratio; the success of the company's risk management activities using derivatives and other financial instruments; the cost of compliance with current and future environmental laws, including climate change laws; risks relating to increased activism and public opposition to fossil fuels and oil sands; risks and uncertainties associated with closing a transaction for the purchase or sale of a business, asset or oil and gas property, including estimates of the final consideration to be paid or received; the ability of counterparties to comply with their obligations in a timely manner; risks associated with joint arrangements in which the company has an interest; risks associated with land claims and Indigenous consultation requirements; the risk that the company may be subject to litigation; the impact of technology and risks associated with developing and implementing new technologies; and the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering that is needed to reduce the margin of error and increase the level of accuracy. The foregoing important factors are not exhaustive.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements are discussed in further detail throughout this MD&A, including under the heading Risk Factors, and the company's 2022 AIF and Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

The forward-looking statements contained in this MD&A are made as of the date of this MD&A. Except as required by applicable securities laws, we assume no obligation to update publicly or otherwise revise any forward-looking statements or the foregoing risks and assumptions affecting such forward-looking statements, whether as a result of new information, future events or otherwise.

EXHIBIT 99-4

Consent of KPMG LLP

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Suncor Energy Inc.

We consent to the use of:

- our report dated March 6, 2023 on the consolidated financial statements of Suncor Energy Inc. (the "Entity") which comprise the consolidated balance sheets as at December 31, 2022 and December 31, 2021, the related consolidated statements of comprehensive income, changes in equity and cash flows for each of the years in the two-year period ended December 31, 2022, and the related notes (collectively the "consolidated financial statements"), and

- our report dated March 6, 2023 on the effectiveness of the Entity's internal control over financial reporting as of December 31, 2022

each of which is included in the Annual Report on Form 40-F of the Entity for the fiscal year ended December 31, 2022.

We also consent to the incorporation by reference of such report(s) in the Registration Statements (No. 333-87604, 333-112234, 333-118648, 333-124415, 333-149532, 333-161021 and 333-161029) on Form S-8, and No. 333-265216 on Form F-10 of the Entity.

"*KPMG LLP*"

Chartered Professional Accountants
Calgary, Canada
March 6, 2023

EXHIBIT 99-5

Consent of GLJ Ltd.

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces and Territories of Canada

Dear Sirs/Mesdames:

Re: Suncor Energy Inc. ("Suncor")

We refer to the following reports (the "**Reports**") prepared by GLJ Ltd. ("**GLJ**"):

- Reserves Assessment and Evaluation of In Situ Oil Sands Properties – Corporate Summary dated February 17, 2023;
- Reserves Assessment and Evaluation of Oil Sands Mining Properties – Corporate Summary dated February 17, 2023;
- Reserves Assessment and Evaluation of the P&NG Reserves of Suncor Energy Inc., Newfoundland Offshore Areas dated February 17, 2023; and
- Reserves Assessment and Evaluation of the P&NG Reserves of Suncor Energy Inc., UK Properties dated February 17, 2023,

which provide GLJ's reports on proved and probable reserves evaluations of Suncor's Canadian mining and in-situ leases, Canadian offshore conventional assets and international operations that were evaluated as at December 31, 2022.

We hereby consent to being named and to the use of, reference to and excerpts and information derived from the said Reports by Suncor in its:

1. Annual Report on Form 40-F for the year ended December 31, 2022 (the "**Form 40-F**") and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-10 (File No. 333-265216) of Suncor, of our Reports;
2. Annual Report for the year ended December 31, 2022 (the "**Annual Report**") to be filed with the securities regulatory authorities of each of the provinces and territories of Canada; and
3. Annual Information Form dated March 6, 2023 (the "**AIF**"), which is incorporated by reference into the following prospectuses (collectively, the "**Prospectuses**"): (i) the short form base shelf prospectus of Suncor dated May 25, 2022 relating to the sale and issue of debt securities, common shares, preferred shares, subscription receipts, warrants, units, share purchase contracts and share purchase units from time to time, and (ii) the short form base shelf prospectus of Suncor dated May 25, 2022 relating to the sale and issue of medium term notes, from time to time.

We have read the Form 40-F, Annual Report, AIF and Prospectuses and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the Reports.

Yours very truly,

GLJ LTD.

"*Tim R. Freeborn*"

Tim R. Freeborn, P. Eng.
Vice-President

Dated: March 6, 2023
Calgary, Alberta, Canada

EXHIBIT 99-6

CERTIFICATION

I, Kris P. Smith, certify that:

1. I have reviewed this annual report on Form 40-F of Suncor Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

DATE: March 6, 2023

/s/ KRIS P. SMITH

Kris P. Smith
Interim President and Chief Executive Officer

EXHIBIT 99-7

CERTIFICATION

I, Alister Cowan, certify that:

1. I have reviewed this annual report on Form 40-F of Suncor Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

DATE: March 6, 2023

/s/ ALISTER COWAN

Alister Cowan
Chief Financial Officer

EXHIBIT 99-8

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2022 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, KRIS P. SMITH, Interim President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ KRIS P. SMITH

Kris P. Smith
Interim President and Chief Executive Officer
Suncor Energy Inc.
DATE: March 6, 2023

EXHIBIT 99-9

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2022 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, ALISTER COWAN, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ ALISTER COWAN

Alister Cowan
Chief Financial Officer
Suncor Energy Inc.
DATE: March 6, 2023

Exhibit 99.10

Supplementary Oil and Gas Disclosures (unaudited)

The following disclosures are presented in accordance with United States Financial Accounting Standards Board ("FASB") Topic 932 — "Extractive Activities — Oil and Gas" and Subpart 1200 of Regulation S-K ("Subpart 1200") of the United States Securities and Exchange Commission. Disclosures pertaining to the audited consolidated financial statements as at and for the year ended December 31, 2022 (the "2022 Consolidated Financial Statements") of Suncor Energy Inc. ("Suncor" or the "company") were prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and Canadian generally accepted accounting principles contained within Part 1 of the Chartered Professional Accountants Canada Handbook, which differ in material respects from financial statements prepared in accordance with United States generally accepted accounting principles. The 2022 Consolidated Financial Statements are attached as Exhibit 99.2 to Suncor's annual report on Form 40-F for the year ended December 31, 2022 (the "Form 40-F").

Reserves Data

Reserves data included herein are estimates only and can be significantly impacted by a variety of internal and external factors. For more information on the risks involved when estimating reserves, see the discussion in the "Statement of Reserves Data and Other Oil and Gas Information — Significant Risk Factors and Uncertainties Affecting Reserves" section in Suncor's 2022 Annual Information Form (the "2022 AIF"), which is attached as Exhibit 99.1 to the Form 40-F. Readers should also see Suncor's Management's Discussion and Analysis for the year ended December 31, 2022, which is attached as Exhibit 99.3 to the Form 40-F (the "2022 Management's Discussion and Analysis").

The reserves data presented herein, with an effective date of December 31, 2022, may differ in relation to the format and the basis from which volumes are economically determined under National Instrument 51-101 — "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), as disclosed in the 2022 AIF. Subpart 1200 requires disclosure of net proved reserves, after royalties, using the average of the first-day-of-the-month prices for the twelve-month period prior to the end of the reporting period, whereas NI 51-101 requires disclosure of gross and net reserves, estimated using forecast prices and costs. In 2022, Suncor's reserves were economic utilizing both constant pricing permitted by Subpart 1200, as well as forecast pricing permitted by NI 51-101.

Net Proved Oil and Gas Reserves [(1)(2)]

The majority of Suncor's oil and gas reserves are in Canada. In order to align with the company's segmented information in the 2022 Consolidated Financial Statements, the 2022 Management's Discussion and Analysis and the 2022 AIF, the company presents the following supplementary oil and gas disclosures by showing amounts associated with its Oil Sands segment, which are exclusively in Canada and produce synthetic crude oil ("SCO") and bitumen, separate from other Canadian operations, which are aggregated with Suncor's international operations (collectively, "Exploration and Production") and produce crude oil, natural gas and natural gas liquids ("NGLs"). Exploration and Production reserves are in offshore Canada and offshore UK.

At December 31, (net reserves, constant prices and costs)	SCO (mmbbls)		Bitumen (mmbbls)		Crude Oil[3] (mmbbls)		Natural Gas (bcf)		Total (mmboe)	
	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021
Proved Developed										
Oil Sands	1,343	1,518	729	826	-	-	-	-	2,071	2,344
Exploration and Production	-	-	-	-	113	128	1	1	113	129
	1,343	1,518	729	826	113	128	1	1	2,184	2,473
Proved Undeveloped										
Oil Sands	756	868	410	398	-	-	-	-	1,166	1,266
Exploration and Production	-	-	-	-	49	21	-	8	49	22
	756	868	410	398	49	21	-	8	1,215	1,288
Proved										
Oil Sands	2,098	2,386	1,139	1,224	-	-	-	-	3,237	3,610
Exploration and Production	-	-	-	-	162	149	1	9	162	150
	2,098	2,386	1,139	1,224	162	149	1	9	3,399	3,760

Reconciliation of Net Proved Oil and Gas Reserves

(net reserves, constant prices and costs)	Balance at December 31 2020	Revisions of Previous Estimates[4]	Improved Recovery[5]	Acquisitions[6]	Extensions and Discoveries[7]	Production	Dispositions[8]	Balance at December 31 2021
Oil Sands								
SCO (mmbbls)	968	1,309	1	-	274	(166)	-	2,386
Bitumen (mmbbls)	354	698	-	-	218	(46)	-	1,224
Exploration and Production								
Crude oil[3] (mmbbls)	144	34	-	4	-	(28)	(6)	149
Natural gas (bcf)	9	1	-	-	-	(1)	-	9
Total (mmboe)	1,468	2,041	1	4	492	(240)	(6)	3,760

(net reserves, constant prices and costs)	Balance at December 31 2021	Revisions of Previous Estimates[4]	Improved Recovery	Acquisitions[6]	Extensions and Discoveries[7]	Production	Dispositions[8]	Balance at December 31 2022
Oil Sands								
SCO (mmbbls)	2,386	(144)	-	-	5	(150)	-	2,098
Bitumen (mmbbls)	1,224	(32)	-	-	2	(54)	-	1,139
Exploration and Production								
Crude oil[3] (mmbbls)	149	-	-	2	44	(25)	(8)	162
Natural gas (bcf)	9	1	-	-	1	(2)	(8)	1
Total (mmboe)	3,760	(175)	-	2	51	(230)	(9)	3,399

Notes to Reserves Data:

(1) Definitions

a. Net reserves, in relation to Suncor's production and reserves, represents the company's working interest share after deduction of royalty obligations, plus the company's royalty interests in production and reserves.

b. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty (at least a 90% probability that the quantities actually recovered will equal or exceed the estimate) to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations.

c. Proved developed oil and gas reserves are those quantities that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and can be expected to be recovered through extraction equipment and infrastructure installed and operational at the time of the reserves estimate for projects that extract oil by means not involving a well.

d. Proved undeveloped oil and gas reserves are those quantities that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion; and can be expected to be recovered through extraction equipment and infrastructure to be installed for projects that extract oil by means not involving a well.

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

(3) Natural gas liquids reserves are not significant and have been presented in combination with crude oil reserves.

(4) Revisions of previous estimates include changes to proved reserves, resulting from new information (except for an increase in proved acreage) normally obtained from development drilling and production history or resulting from a change in economic factors, such as changes in constant prices used for the reserve evaluation. In 2022, downward technical revisions of SCO was made primarily at Syncrude and Firebag, and partially offset by positive revisions at Millenium and North Steepbank Extension. Downward technical revisions of bitumen was made primarily at Fort Hills and MacKay River, and partially offset by positive revisions at Syncrude and Firebag.

(5) Improved recoveries relates to additions to reserves resulting from deployment of improved recovery schemes such as Steam Assisted Gravity Drainage in In Situ and waterflood in Exploration and Production.

(6) Acquisitions in 2021 are due to Suncor finalizing a new ownership agreement for Terra Nova in the third quarter, which increased Suncor's working interest from 37.675% to 48%. Acquisitions in 2022 are due to Suncor increasing its interest in the White Rose assets by 12.5% to 40% in the base project and 38.6% in the White Rose extension.

(7) Extensions and discoveries are additions to proved reserves from proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery or discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. Proved undeveloped reserves associated with Suncor's MacKay River In Situ project and Syncrude Mildred Lake West project were added in 2021. Proved undeveloped reserves associated with White Rose and proved developed reserves associated with Firebag, Hebron, and U.K. Buzzard were added in 2022.

(8) Dispositions relate to Suncor completing the sale of its 26.69% working interest in the Golden Eagle Area Development in the U.K. early in the fourth quarter of 2021 and the sale of its 30% working interest in Oda and its 17.5% working interest in the Fenja Development Joint Operations in Norway in the third quarter of 2022.

Capitalized Costs

($ millions)	At December 31, 2022 Oil Sands	Exploration and Production	Total	At December 31, 2021 Oil Sands	Exploration and Production	Total
Exploration and evaluation assets[1]	1,979	16	1,995	2,012	215	2,227
Oil and gas properties[2][3]	23,058	15,717	38,775	19,841	20,477	40,318
Plant and equipment[2][3]	69,543	823	70,366	68,009	1,018	69,027
- accumulated provision[2]	(45,288)	(11,360)	(56,648)	(37,971)	(15,999)	(53,970)
Total	49,292	5,196	54,488	51,891	5,711	57,602

(1) Exploration and evaluation assets largely represent amounts associated with unproved properties, but may include properties with proved reserves for which Suncor's Board of Directors have not sanctioned development. See note 18 of the 2022 Consolidated Financial Statements.

(2) Oil and Gas Properties, Plant and Equipment and the accumulated provision largely represent amounts associated with proved properties. See note 15 of the 2022 Consolidated Financial Statements. Includes amounts capitalized to Property, Plant and Equipment on the Consolidated Balance Sheets of the 2022 Consolidated Financial Statements that relate to the company's right-of-use assets under IFRS 16. See note 17 of the 2022 Consolidated Financial Statements.

(3) Includes amounts capitalized to Property, Plant and Equipment on the Consolidated Balance Sheets of the 2022 Consolidated Financial Statements that relate to the company's decommissioning and restoration activities.

Costs Incurred for Property Acquisition, Exploration and Development Activities

($ millions)	Year ended December 31, 2022 Oil Sands	Exploration and Production	Total	Year Ended December 31, 2021 Oil Sands	Exploration and Production	Total
Unproved property acquisition	-	-	-	-	-	-
Proved property acquisition[1]	-	-	-	-	65	65
Exploration[2]	38	60	98	15	36	51
Development[3]	3,633	548	4,181	3,172	222	3,394
Total	3,671	608	4,279	3,187	323	3,510

(1) Proved property acquisitions in 2021 are primarily due to Suncor finalizing a new ownership agreement for Terra Nova in the third quarter of 2021, which increased Suncor's working interest from 37.675% to 48%.

(2) Includes amounts capitalized to Exploration and Evaluation on the Consolidated Balance Sheets as well as those charged to Exploration Expense on the Consolidated Statements of Comprehensive Income (Loss), of the 2022 Consolidated Financial Statements.

(3) Includes amounts capitalized to Property, Plant and Equipment on the Consolidated Balance Sheets of the 2022 Consolidated Financial Statements that relate to the company's decommissioning and restoration activities.

Results of Operations for Oil and Gas Producing Activities

($ millions)	Year ended December 31, 2022 Oil Sands	Exploration and Production	Total	Year Ended December 31, 2021 Oil Sands	Exploration and Production	Total
Operating revenues, net of royalties	26,468	3,723	30,191	18,397	2,500	20,897
Other income (loss)	(53)	164	111	6	17	23
	26,415	3,887	30,302	18,403	2,517	20,920
Purchases of crude oil and products	2,050	-	2,050	1,444	-	1,444
Operating, selling and general	9,152	490	9,642	8,056	429	8,485
Transportation and distribution	1,210	101	1,311	1,126	112	1,238
Depreciation, depletion, amortization and impairment	7,927	(105)	7,822	4,585	324	4,909
Exploration	37	19	56	12	35	47
(Gain) loss on disposal of assets	(7)	66	59	(4)	(227)	(231)
Financing expenses	413	95	508	359	53	412
Earnings before income taxes	5,633	3,221	8,854	2,825	1,791	4,616
Income tax expense	1,314	925	2,239	678	506	1,184
Net earnings	4,319	2,296	6,615	2,147	1,285	3,432

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (1)

The standardized measure of discounted future net cash flows relating to Suncor 's proved oil and gas reserves are calculated in accordance with FASB Topic 932 — "Extractive Activities — Oil and Gas". Future cash inflows are estimated using the average of the first-day-of-the-month prices for the twelve-month period prior to the end of the reporting period, which are also used in estimating the entity's proved oil and gas reserves. Future development and production costs, including the associated decommissioning and restoration activities, are calculated by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. The appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, were applied to the future pretax net cash flows, less the tax basis of the properties involved. A prescribed rate of 10% is applied to discount the future net cash flows.

The calculation of the standardized measure of discounted future net cash flows is based upon information prepared by the company's independent qualified reserves evaluator (which includes decommissioning and restoration activities), and adjusted for future income taxes.

It should not be assumed that the estimates of future net cash flows presented in the tables below represent the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material. Future changes to income tax, royalty and environmental regulations could also have a significant impact on the respective assumptions. There is no guarantee that the estimates for SCO, bitumen, crude oil, and natural gas reserves provided herein will be recovered. Actual SCO, bitumen, crude oil, and natural gas reserves may be greater than or less than the estimates provided herein.

The following twelve-month average prices were used to calculate the standardized measure of discounted future net cash flows (using the first-day-of-the-month prices for the twelve-month period prior to the end of the reporting period):

Year	Brent North Sea	WTI Cushing Oklahoma	WCS Hardisty Alberta	Light Sweet Edmonton Alberta	Pentanes Plus Edmonton Alberta	AECO Gas	National Balancing Point North Sea
	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu
2022	97.98	94.13	98.14	119.59	120.70	5.59	42.80
2021	69.22	66.56	66.94	78.39	83.66	3.41	18.38

($ millions)	At December 31, 2022			At December 31, 2021		
	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Future cash inflows	353,676	20,253	373,929	259,065	12,699	271,764
Future production costs	(148,250)	(4,915)	(153,165)	(121,138)	(3,527)	(124,665)
Future development costs	(69,267)	(4,755)	(74,022)	(56,346)	(2,537)	(58,883)
Future income tax expenses	(31,615)	(3,993)	(35,608)	(17,839)	(1,803)	(19,642)
Future net cash flows	104,544	6,590	111,134	63,742	4,832	68,574
10% Discount Factor	(48,137)	(1,528)	(49,665)	(32,377)	(821)	(33,198)
Standardized measure of discounted future net cash flows	56,407	5,062	61,469	31,365	4,011	35,376

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

($ millions)	2022	2021
Standardized measure of discounted future net cash flows - beginning of year	35,376	6,837
Sales and transfers of oil and gas produced	(9,820)	(3,184)
Net changes in sales prices and operating costs related to future production	45,518	43,572
Net change due to extensions, discoveries and improved recovery	2,710	2,766
Net change due to acquisition and dispositions	(128)	201
Net change due to revisions in quantity estimates	(4,650)	(8,537)
Previously estimated development costs incurred during the period	4,036	3,692
Changes in estimated future development costs	(6,082)	(2,448)
Accretion of discount	4,143	717
Net change in income taxes	(9,637)	(8,239)
Standardized measure of discounted future net cash flows - end of year	61,469	35,376

(1) Tables may not add due to rounding.