
# Annual Information Form

Dated February 23, 2022

SUNCOR

# Statement of Reserves Data and Other Oil and Gas Information

## Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information outlined below is dated February 23, 2022, with an effective date of December 31, 2021. 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 information is January 10, 2022.

## 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., contained in its report dated February 18, 2022 (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 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 Industry Conditions and Risk Factors herein. The accuracy of any reserves estimate is a matter of interpretation and judgment and is a function of the quality and quantity of available data, which may have been gathered over time. For these reasons, estimates of the reserves and categorization of such reserves based on the certainty of recovery, prepared by different engineers or by the same engineers at different times, may vary.

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

The reserves evaluations are based in part on the assumed success of activities the company intends to undertake in future years. The 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. Refer to the Risk Factors – Volatility of Commodity Prices section of this AIF.

- Carbon Risk

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

- Political Unrest

  As a result of political unrest in Syria, Suncor reclassified all Syria reserves to contingent resources, effective December 31, 2012. Suncor also reclassified all Libya reserves to contingent resources, effective December 31, 2016, due to political unrest in Libya. All Syria and Libya volumes remain classified as contingent resources as at December 31, 2021. The criteria for the reclassification of the aforementioned volumes back to reserves include sustained periods of political stability, operational and production stability, and normalization of business relations including financial transactions. Refer to the Risk Factors – Foreign Operations section of this AIF.

- Abandonment and Reclamation costs

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

- Government Action

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

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

## Oil and Gas Reserves Tables and Notes

### Summary of Oil and Gas Reserves[1]

as at December 31, 2021
(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 | 1 442 | 1 283 | 787 | 734 | — | — | — | — | 2 229 | 2 018 |
| In Situ | 275 | 228 | 93 | 73 | — | — | — | — | 367 | 301 |
| E&P Canada | — | — | — | — | 74 | 68 | — | — | 74 | 68 |
| Total Canada | 1 717 | 1 511 | 880 | 807 | 74 | 68 | — | — | 2 671 | 2 387 |
| Offshore U.K. & Norway | — | — | — | — | 39 | 39 | 2 | 2 | 40 | 40 |
| **Total Proved Developed Producing** | **1 717** | **1 511** | **880** | **807** | **114** | **108** | **2** | **2** | **2 711** | **2 426** |
| ***Proved Developed Non-Producing*** | | | | | | | | | | |
| Mining | — | — | — | — | — | — | — | — | — | — |
| In Situ | — | — | — | — | — | — | — | — | — | — |
| E&P Canada | — | — | — | — | 23 | 20 | — | — | 23 | 20 |
| Total Canada | — | — | — | — | 23 | 20 | — | — | 23 | 20 |
| Offshore U.K. & Norway | — | — | — | — | — | — | — | — | — | — |
| **Total Proved Developed Non-Producing** | **—** | **—** | **—** | **—** | **23** | **20** | **—** | **—** | **23** | **20** |
| ***Proved Undeveloped*** | | | | | | | | | | |
| Mining | 295 | 272 | — | — | — | — | — | — | 295 | 272 |
| In Situ | 715 | 578 | 478 | 391 | — | — | — | — | 1 193 | 969 |
| E&P Canada | — | — | — | — | 15 | 12 | — | — | 15 | 12 |
| Total Canada | 1 010 | 850 | 478 | 391 | 15 | 12 | — | — | 1 504 | 1 253 |
| Offshore U.K. & Norway | — | — | — | — | 7 | 7 | 11 | 11 | 9 | 9 |
| **Total Proved Undeveloped** | **1 010** | **850** | **478** | **391** | **23** | **19** | **11** | **11** | **1 513** | **1 262** |
| ***Proved*** | | | | | | | | | | |
| Mining | 1 737 | 1 556 | 787 | 734 | — | — | — | — | 2 524 | 2 290 |
| In Situ | 990 | 805 | 571 | 464 | — | — | — | — | 1 561 | 1 269 |
| E&P Canada | — | — | — | — | 113 | 101 | — | — | 113 | 101 |
| Total Canada | 2 727 | 2 361 | 1 358 | 1 198 | 113 | 101 | — | — | 4 197 | 3 660 |
| Offshore U.K. & Norway | — | — | — | — | 46 | 46 | 13 | 13 | 49 | 49 |
| **Total Proved** | **2 727** | **2 361** | **1 358** | **1 198** | **159** | **147** | **13** | **13** | **4 246** | **3 708** |
| ***Probable*** | | | | | | | | | | |
| Mining | 403 | 354 | 461 | 394 | — | — | — | — | 864 | 748 |
| In Situ | 1 275 | 977 | 336 | 254 | — | — | — | — | 1 611 | 1 231 |
| E&P Canada | — | — | — | — | 103 | 78 | — | — | 103 | 78 |
| Total Canada | 1 678 | 1 332 | 797 | 648 | 103 | 78 | — | — | 2 578 | 2 058 |
| Offshore U.K. & Norway | — | — | — | — | 16 | 16 | 6 | 6 | 17 | 17 |
| **Total Probable** | **1 678** | **1 332** | **797** | **648** | **119** | **94** | **6** | **6** | **2 595** | **2 075** |
| ***Proved Plus Probable*** | | | | | | | | | | |
| Mining | 2 140 | 1 910 | 1 248 | 1 128 | — | — | — | — | 3 387 | 3 038 |
| In Situ | 2 265 | 1 783 | 907 | 718 | — | — | — | — | 3 172 | 2 501 |
| E&P Canada | — | — | — | — | 215 | 179 | — | — | 215 | 179 |
| Total Canada | 4 405 | 3 693 | 2 155 | 1 846 | 215 | 179 | — | — | 6 775 | 5 717 |
| Offshore U.K. & Norway | — | — | — | — | 63 | 63 | 19 | 19 | 66 | 66 |
| **Total Proved Plus Probable** | **4 405** | **3 693** | **2 155** | **1 846** | **278** | **241** | **19** | **19** | **6 841** | **5 783** |

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, 2021
(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, 2020** | 1 980 | 426 | 2 406 | 865 | 554 | 1 418 | — | — | — | — | — | — | 2 845 | 980 | 3 824 |
| Extensions & Improved Recovery[7] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Technical Revisions[8] | (104) | (24) | (128) | (60) | (93) | (153) | — | — | — | — | — | — | (164) | (116) | (280) |
| Discoveries[9] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Acquisitions[10] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Dispositions[11] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Economic Factors[12] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Production[13] | (139) | — | (139) | (18) | — | (18) | — | — | — | — | — | — | (157) | — | (157) |
| **December 31, 2021** | **1 737** | **403** | **2 140** | **787** | **461** | **1 248** | **—** | **—** | **—** | **—** | **—** | **—** | **2 524** | **864** | **3 387** |
| ***In Situ*** | | | | | | | | | | | | | | | |
| **December 31, 2020** | 997 | 1 286 | 2 283 | 628 | 328 | 957 | — | — | — | — | — | — | 1 625 | 1 614 | 3 240 |
| Extensions & Improved Recovery[7] | 3 | 1 | 4 | 1 | — | 1 | — | — | — | — | — | — | 4 | — | 5 |
| Technical Revisions[8] | 32 | (11) | 21 | (24) | 8 | (16) | — | — | — | — | — | — | 8 | (3) | 5 |
| Discoveries[9] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Acquisitions[10] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Dispositions[11] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Economic Factors[12] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Production[13] | (43) | — | (43) | (34) | — | (34) | — | — | — | — | — | — | (77) | — | (77) |
| **December 31, 2021** | **990** | **1 275** | **2 265** | **571** | **336** | **907** | **—** | **—** | **—** | **—** | **—** | **—** | **1 561** | **1 611** | **3 172** |
| ***E&P Canada*** | | | | | | | | | | | | | | | |
| **December 31, 2020** | — | — | — | — | — | — | 109 | 100 | 209 | — | — | — | 109 | 100 | 209 |
| Extensions & Improved Recovery[7] | — | — | — | — | — | — | — | 1 | 1 | — | — | — | — | 1 | 1 |
| Technical Revisions[8] | — | — | — | — | — | — | 17 | (3) | 14 | — | — | — | 17 | (3) | 14 |
| Discoveries[9] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Acquisitions[10] | — | — | — | — | — | — | 5 | 2 | 7 | — | — | — | 5 | 2 | 7 |
| Dispositions[11] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Economic Factors[12] | — | — | — | — | — | — | 2 | 3 | 4 | — | — | — | 2 | 3 | 4 |
| Production[13] | — | — | — | — | — | — | (20) | — | (20) | — | — | — | (20) | — | (20) |
| **December 31, 2021** | **—** | **—** | **—** | **—** | **—** | **—** | **113** | **103** | **215** | **—** | **—** | **—** | **113** | **103** | **215** |
| ***Total Canada*** | | | | | | | | | | | | | | | |
| **December 31, 2020** | 2 977 | 1 712 | 4 689 | 1 493 | 882 | 2 375 | 109 | 100 | 209 | — | — | — | 4 579 | 2 694 | 7 273 |
| Extensions & Improved Recovery[7] | 3 | 1 | 4 | 1 | — | 1 | — | 1 | 1 | — | — | — | 4 | 1 | 5 |
| Technical Revisions[8] | (72) | (35) | (107) | (84) | (84) | (169) | 17 | (3) | 14 | — | — | — | (139) | (122) | (261) |
| Discoveries[9] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Acquisitions[10] | — | — | — | — | — | — | 5 | 2 | 7 | — | — | — | 5 | 2 | 7 |
| Dispositions[11] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Economic Factors[12] | — | — | — | — | — | — | 2 | 3 | 4 | — | — | — | 2 | 3 | 4 |
| Production[13] | (182) | — | (182) | (52) | — | (52) | (20) | — | (20) | — | — | — | (253) | — | (253) |
| **December 31, 2021** | **2 727** | **1 678** | **4 405** | **1 358** | **797** | **2 155** | **113** | **103** | **215** | **—** | **—** | **—** | **4 197** | **2 578** | **6 775** |

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, 2021
(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 |
| ***Offshore U.K. & Norway*** | | | | | | | | | | | | | | | |
| **December 31, 2020** | — | — | — | — | — | — | 61 | 22 | 83 | 12 | 5 | 17 | 63 | 23 | 86 |
| Extensions & Improved Recovery[7] | — | — | — | — | — | — | 1 | — | 1 | — | — | — | 1 | — | 1 |
| Technical Revisions[8] | — | — | — | — | — | — | (1) | (3) | (3) | 2 | 1 | 2 | (1) | (2) | (3) |
| Discoveries[9] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Acquisitions[10] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Dispositions[11] | — | — | — | — | — | — | (6) | (3) | (9) | — | — | — | (6) | (3) | (9) |
| Economic Factors[12] | — | — | — | — | — | — | 2 | (1) | 1 | — | — | — | 2 | (1) | 1 |
| Production[13] | — | — | — | — | — | — | (11) | — | (11) | (1) | — | (1) | (11) | — | (11) |
| **December 31, 2021** | **—** | **—** | **—** | **—** | **—** | **—** | **46** | **16** | **63** | **13** | **6** | **19** | **49** | **17** | **66** |
| ***Total*** | | | | | | | | | | | | | | | |
| **December 31, 2020** | 2 977 | 1 712 | 4 689 | 1 493 | 882 | 2 375 | 170 | 123 | 292 | 12 | 5 | 17 | 4 642 | 2 717 | 7 359 |
| Extensions & Improved Recovery[7] | 3 | 1 | 4 | 1 | — | 1 | 1 | 1 | 1 | — | — | — | 5 | 1 | 6 |
| Technical Revisions[8] | (72) | (35) | (107) | (84) | (84) | (169) | 16 | (5) | 11 | 2 | 1 | 2 | (140) | (124) | (264) |
| Discoveries[9] | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Acquisitions[10] | — | — | — | — | — | — | 5 | 2 | 7 | — | — | — | 5 | 2 | 7 |
| Dispositions[11] | — | — | — | — | — | — | (6) | (3) | (9) | — | — | — | (6) | (3) | (9) |
| Economic Factors[12] | — | — | — | — | — | — | 4 | 1 | 5 | — | — | — | 4 | 1 | 5 |
| Production[13] | (182) | — | (182) | (52) | — | (52) | (30) | — | (30) | (1) | — | (1) | (264) | — | (264) |
| **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** |

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, 2021

(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 53 mmbbls, proved undeveloped of 2 mmbbls, proved of 55 mmbbls, probable of 25 mmbbls and proved plus probable of 80 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 51 mmbbls, proved undeveloped of 1 mmbbls, proved of 52 mmbbls, probable of 18 mmbbls and proved plus probable of 70 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 12 mmbbls, probable of (0.1) mmbbls and proved plus probable of 12 mmbbls.

(6) Conventional natural gas includes immaterial amounts of NGLs (0.6 mmbbls of proved and 0.8 mmbbls of proved plus probable NGLs).

(7) Extensions & improved recovery are additions to the reserves resulting from step-out drilling, infill drilling and implementation of improved recovery schemes. Negative volumes, if any, for probable reserves result from the transfer of probable reserves to proved reserves. Changes in 2021 are primarily a result of drilling extensions and improved recovery at Firebag.

(8) Technical revisions include changes in previous estimates resulting from new technical data or revised interpretations. Changes in 2021 are primarily due to new information obtained during the year, including drilling results and ongoing field performance. In 2021, Mining changes are primarily due to mine plan updates at Fort Hills and Syncrude, the majority of which improve the economics. In 2021, 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 2021.

(10) Acquisitions are additions to reserves estimates as a result of purchasing interests in oil and gas properties. In 2021, Suncor increased its working interest in Terra Nova through acquisition and in Hibernia through redetermination.

(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 2021, Suncor divested its interest in the Golden Eagle Area Development – refer to 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, 2021
(forecast prices and costs)

| | (in $ millions, discounted at % per year) | | | | | Unit Value[2] |
|---|---|---|---|---|---|---|
| | 0% | 5% | 10% | 15% | 20% | ($/boe) |
| ***Proved Developed Producing*** | | | | | | |
| Mining | 27 046 | 25 954 | 20 318 | 16 126 | 13 232 | 10.07 |
| In Situ | 11 546 | 10 037 | 8 828 | 7 873 | 7 112 | 29.34 |
| E&P Canada | 3 503 | 3 184 | 2 884 | 2 629 | 2 417 | 42.29 |
| Total Canada | 42 096 | 39 175 | 32 030 | 26 628 | 22 761 | 13.42 |
| Offshore U.K. & Norway | 1 705 | 1 686 | 1 574 | 1 449 | 1 334 | 39.71 |
| **Total Proved Developed Producing** | **43 801** | **40 861** | **33 604** | **28 077** | **24 095** | **13.85** |
| ***Proved Developed Non-Producing*** | | | | | | |
| Mining | — | — | — | — | — | — |
| In Situ | — | — | — | — | — | — |
| E&P Canada | 247 | 316 | 341 | 344 | 335 | 16.88 |
| Total Canada | 247 | 316 | 341 | 344 | 335 | 16.88 |
| Offshore U.K. & Norway | — | — | — | — | — | — |
| **Total Proved Developed Non-Producing** | **247** | **316** | **341** | **344** | **335** | **16.88** |
| ***Proved Undeveloped*** | | | | | | |
| Mining | 3 715 | 2 473 | 1 419 | 786 | 416 | 5.22 |
| In Situ | 35 277 | 18 676 | 10 803 | 6 733 | 4 454 | 11.15 |
| E&P Canada | 491 | 438 | 382 | 332 | 290 | 31.47 |
| Total Canada | 39 483 | 21 587 | 12 605 | 7 852 | 5 161 | 10.06 |
| Offshore U.K. & Norway | 568 | 436 | 350 | 290 | 246 | 38.79 |
| **Total Proved Undeveloped** | **40 051** | **22 023** | **12 955** | **8 142** | **5 407** | **10.27** |
| ***Proved*** | | | | | | |
| Mining | 30 761 | 28 428 | 21 737 | 16 913 | 13 649 | 9.49 |
| In Situ | 46 823 | 28 713 | 19 631 | 14 606 | 11 566 | 15.47 |
| E&P Canada | 4 241 | 3 937 | 3 608 | 3 306 | 3 042 | 35.87 |
| Total Canada | 81 826 | 61 078 | 44 976 | 34 825 | 28 257 | 12.29 |
| Offshore U.K. & Norway | 2 273 | 2 122 | 1 924 | 1 739 | 1 580 | 39.54 |
| **Total Proved** | **84 099** | **63 200** | **46 900** | **36 564** | **29 837** | **12.65** |
| ***Probable*** | | | | | | |
| Mining | 19 855 | 9 650 | 5 417 | 3 507 | 2 536 | 7.24 |
| In Situ | 76 271 | 20 169 | 7 528 | 3 850 | 2 473 | 6.11 |
| E&P Canada | 5 103 | 3 650 | 2 676 | 2 030 | 1 590 | 34.23 |
| Total Canada | 101 228 | 33 469 | 15 620 | 9 386 | 6 599 | 7.59 |
| Offshore U.K. & Norway | 1 066 | 852 | 692 | 578 | 497 | 40.72 |
| **Total Probable** | **102 294** | **34 321** | **16 312** | **9 965** | **7 096** | **7.86** |
| ***Proved Plus Probable*** | | | | | | |
| Mining | 50 616 | 38 078 | 27 154 | 20 419 | 16 185 | 8.94 |
| In Situ | 123 094 | 48 881 | 27 159 | 18 456 | 14 039 | 10.86 |
| E&P Canada | 9 344 | 7 587 | 6 284 | 5 335 | 4 633 | 35.16 |
| Total Canada | 183 054 | 94 547 | 60 597 | 44 211 | 34 857 | 10.60 |
| Offshore U.K. & Norway | 3 340 | 2 974 | 2 616 | 2 317 | 2 077 | 39.84 |
| **Total Proved Plus Probable** | **186 394** | **97 521** | **63 212** | **46 528** | **36 934** | **10.93** |

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, 2021
(forecast prices and costs)

| | (in $ millions, discounted at % per year) | | | | |
|---|---|---|---|---|---|
| | 0% | 5% | 10% | 15% | 20% |
| ***Proved Developed Producing*** | | | | | |
| Mining | 19 905 | 20 730 | 16 319 | 12 941 | 10 609 |
| In Situ | 9 066 | 7 888 | 6 932 | 6 175 | 5 573 |
| E&P Canada | 2 892 | 2 649 | 2 406 | 2 196 | 2 019 |
| Total Canada | 31 863 | 31 267 | 25 657 | 21 312 | 18 200 |
| Offshore U.K. & Norway | 1 227 | 1 179 | 1 085 | 989 | 905 |
| **Total Proved Developed Producing** | **33 091** | **32 446** | **26 742** | **22 302** | **19 105** |
| ***Proved Developed Non-Producing*** | | | | | |
| Mining | — | — | — | — | — |
| In Situ | — | — | — | — | — |
| E&P Canada | 166 | 220 | 241 | 244 | 237 |
| Total Canada | 166 | 220 | 241 | 244 | 237 |
| Offshore U.K. & Norway | — | — | — | — | — |
| **Total Proved Developed Non-Producing** | **166** | **220** | **241** | **244** | **237** |
| ***Proved Undeveloped*** | | | | | |
| Mining | 2 534 | 1 764 | 976 | 501 | 227 |
| In Situ | 26 979 | 14 072 | 8 026 | 4 935 | 3 220 |
| E&P Canada | 365 | 324 | 280 | 240 | 208 |
| Total Canada | 29 878 | 16 159 | 9 282 | 5 676 | 3 655 |
| Offshore U.K. & Norway | 124 | 120 | 117 | 112 | 108 |
| **Total Proved Undeveloped** | **30 002** | **16 279** | **9 399** | **5 789** | **3 762** |
| ***Proved*** | | | | | |
| Mining | 22 440 | 22 494 | 17 295 | 13 442 | 10 836 |
| In Situ | 36 045 | 21 959 | 14 958 | 11 110 | 8 793 |
| E&P Canada | 3 423 | 3 192 | 2 927 | 2 680 | 2 463 |
| Total Canada | 61 907 | 47 646 | 35 180 | 27 232 | 22 092 |
| Offshore U.K. & Norway | 1 351 | 1 299 | 1 202 | 1 102 | 1 012 |
| **Total Proved** | **63 258** | **48 945** | **36 381** | **28 334** | **23 104** |
| ***Probable*** | | | | | |
| Mining | 15 476 | 7 399 | 4 063 | 2 589 | 1 856 |
| In Situ | 58 680 | 15 381 | 5 755 | 2 970 | 1 925 |
| E&P Canada | 3 826 | 2 747 | 2 009 | 1 518 | 1 185 |
| Total Canada | 77 982 | 25 528 | 11 826 | 7 077 | 4 965 |
| Offshore U.K. & Norway | 523 | 439 | 367 | 313 | 274 |
| **Total Probable** | **78 505** | **25 967** | **12 193** | **7 391** | **5 240** |
| ***Proved Plus Probable*** | | | | | |
| Mining | 37 916 | 29 893 | 21 358 | 16 032 | 12 692 |
| In Situ | 94 724 | 37 340 | 20 712 | 14 080 | 10 717 |
| E&P Canada | 7 249 | 5 939 | 4 935 | 4 197 | 3 648 |
| Total Canada | 139 889 | 73 173 | 47 006 | 34 309 | 27 058 |
| Offshore U.K. & Norway | 1 874 | 1 739 | 1 569 | 1 415 | 1 287 |
| **Total Proved Plus Probable** | **141 763** | **74 912** | **48 575** | **35 724** | **28 344** |

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

## Total Future Net Revenues[1]

as at December 31, 2021
(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 | 183 935 | 17 851 | 92 963 | 25 782 | 20 292 | 27 046 | 7 141 | 19 905 |
| In Situ | 31 697 | 5 029 | 11 554 | 2 844 | 722 | 11 546 | 2 480 | 9 066 |
| E&P Canada | 6 819 | 665 | 1 486 | 127 | 1 038 | 3 503 | 611 | 2 892 |
| Total Canada | 222 450 | 23 545 | 106 004 | 28 753 | 22 052 | 42 096 | 10 233 | 31 863 |
| Offshore U.K. & Norway | 3 771 | — | 1 378 | 128 | 560 | 1 705 | 478 | 1 227 |
| **Total Proved Developed Producing** | **226 220** | **23 545** | **107 382** | **28 881** | **22 611** | **43 801** | **10 710** | **33 091** |
| ***Proved Developed Non-Producing*** | | | | | | | | |
| Mining | — | — | — | — | — | — | — | — |
| In Situ | — | — | — | — | — | — | — | — |
| E&P Canada | 2 140 | 220 | 931 | 192 | 550 | 247 | 81 | 166 |
| Total Canada | 2 140 | 220 | 931 | 192 | 550 | 247 | 81 | 166 |
| Offshore U.K. & Norway | — | — | — | — | — | — | — | — |
| **Total Proved Developed Non-Producing** | **2 140** | **220** | **931** | **192** | **550** | **247** | **81** | **166** |
| ***Proved Undeveloped*** | | | | | | | | |
| Mining | 28 590 | 2 270 | 16 972 | 4 091 | 1 542 | 3 715 | 1 181 | 2 534 |
| In Situ | 106 353 | 19 178 | 32 147 | 18 499 | 1 252 | 35 277 | 8 298 | 26 979 |
| E&P Canada | 1 381 | 342 | 213 | 305 | 29 | 491 | 126 | 365 |
| Total Canada | 136 324 | 21 791 | 49 332 | 22 895 | 2 823 | 39 483 | 9 605 | 29 878 |
| Offshore U.K. & Norway | 828 | — | 154 | 57 | 48 | 568 | 445 | 124 |
| **Total Proved Undeveloped** | **137 152** | **21 791** | **49 486** | **22 952** | **2 871** | **40 051** | **10 049** | **30 002** |
| ***Proved*** | | | | | | | | |
| Mining | 212 525 | 20 121 | 109 935 | 29 874 | 21 833 | 30 761 | 8 322 | 22 440 |
| In Situ | 138 049 | 24 208 | 43 701 | 21 343 | 1 975 | 46 823 | 10 778 | 36 045 |
| E&P Canada | 10 339 | 1 228 | 2 630 | 623 | 1 617 | 4 241 | 818 | 3 423 |
| Total Canada | 360 914 | 45 556 | 156 267 | 51 840 | 25 425 | 81 826 | 19 918 | 61 907 |
| Offshore U.K. & Norway | 4 599 | — | 1 532 | 186 | 608 | 2 273 | 923 | 1 351 |
| **Total Proved** | **365 512** | **45 556** | **157 799** | **52 026** | **26 033** | **84 099** | **20 841** | **63 258** |
| ***Probable*** | | | | | | | | |
| Mining | 84 395 | 11 350 | 38 139 | 10 262 | 4 790 | 19 855 | 4 378 | 15 476 |
| In Situ | 216 678 | 47 015 | 59 768 | 32 042 | 1 582 | 76 271 | 17 591 | 58 680 |
| E&P Canada | 9 996 | 2 652 | 1 512 | 502 | 227 | 5 103 | 1 277 | 3 826 |
| Total Canada | 311 069 | 61 017 | 99 419 | 42 807 | 6 598 | 101 228 | 23 246 | 77 982 |
| Offshore U.K. & Norway | 1 716 | — | 591 | 22 | 38 | 1 066 | 544 | 523 |
| **Total Probable** | **312 785** | **61 017** | **100 009** | **42 828** | **6 636** | **102 294** | **23 790** | **78 505** |
| ***Proved Plus Probable*** | | | | | | | | |
| Mining | 296 920 | 31 471 | 148 074 | 40 136 | 26 623 | 50 616 | 12 700 | 37 916 |
| In Situ | 354 727 | 71 223 | 103 469 | 53 385 | 3 556 | 123 094 | 28 370 | 94 724 |
| E&P Canada | 20 335 | 3 879 | 4 142 | 1 126 | 1 844 | 9 344 | 2 095 | 7 249 |
| Total Canada | 671 982 | 106 573 | 255 685 | 94 647 | 32 023 | 183 054 | 43 165 | 139 889 |
| Offshore U.K. & Norway | 6 315 | — | 2 123 | 207 | 645 | 3 340 | 1 466 | 1 874 |
| **Total Proved Plus Probable** | **678 297** | **106 573** | **257 808** | **94 854** | **32 669** | **186 394** | **44 631** | **141 763** |

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

**Future Net Revenues by Product Type[1]**

as at December 31, 2021
(forecast prices and costs)

| (before income taxes, discounted at 10% per year) | $ millions | Unit Value $/boe[2] |
|---|---|---|
| ***Proved Developed Producing*** | | |
| SCO | 21 582 | 14.28 |
| Bitumen | 7 563 | 9.37 |
| Light Crude Oil & Medium Crude Oil | 2 389 | 42.26 |
| Heavy Crude Oil | 2 056 | 40.32 |
| Conventional Natural Gas[3] | 14 | 42.92 |
| **Total Proved Developed Producing** | **33 604** | **13.85** |
| ***Proved*** | | |
| SCO | 30 337 | 12.85 |
| Bitumen | 11 031 | 9.21 |
| Light Crude Oil & Medium Crude Oil | 3 437 | 36.20 |
| Heavy Crude Oil | 1 930 | 37.02 |
| Conventional Natural Gas[3] | 166 | 76.21 |
| **Total Proved** | **46 900** | **12.65** |
| ***Proved Plus Probable*** | | |
| SCO | 41 094 | 11.13 |
| Bitumen | 13 218 | 7.16 |
| Light Crude Oil & Medium Crude Oil | 6 035 | 35.24 |
| Heavy Crude Oil | 2 613 | 37.34 |
| Conventional Natural Gas[3] | 251 | 80.25 |
| **Total Proved Plus Probable** | **63 212** | **10.93** |

(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 2037 and 100% thereafter. These assumptions have resulted in a $0.7 billion increase in the net present value of future net revenues (total proved plus probable reserves, before tax, discounted at 10%) attributable to In Situ production relative to the bitumen sale-only scenario.

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, 2022), Sproule Associates Limited (dated December 31, 2021) and McDaniel & Associates Consultants Ltd. (dated January 1, 2022), all of whom are independent qualified reserves evaluators. Resultant forecasts are set out below. To the extent there are fixed or presently determinable future prices to which Suncor is legally bound by contractual or other obligations to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices have been incorporated into the forecast prices as applied to the pertinent properties. Benchmark forecast prices have been adjusted for quality differentials and transportation costs applicable to the specific evaluation areas and products. The inflation rates utilized in cost forecasts were nil in 2022, 2.3% in 2023 and 2.0% thereafter.

### 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 |
| 2021(8) | 70.75 | 67.95 | 54.90 | 80.30 | 79.06 | 3.52 | 16.82 |
| 2022 | 75.33 | 72.83 | 74.43 | 86.82 | 91.85 | 3.56 | 25.84 |
| 2023 | 71.46 | 68.78 | 69.17 | 80.73 | 85.53 | 3.20 | 15.13 |
| 2024 | 69.62 | 66.76 | 66.54 | 78.01 | 82.98 | 3.05 | 10.50 |
| 2025 | 71.01 | 68.09 | 67.87 | 79.57 | 84.63 | 3.10 | 10.71 |
| 2026 | 72.44 | 69.45 | 69.23 | 81.16 | 86.33 | 3.17 | 10.92 |
| 2027 | 73.88 | 70.84 | 70.61 | 82.78 | 88.05 | 3.23 | 11.15 |
| 2028 | 75.36 | 72.26 | 72.02 | 84.44 | 89.82 | 3.30 | 11.37 |
| 2029 | 76.87 | 73.70 | 73.46 | 86.13 | 91.61 | 3.36 | 11.59 |
| 2030 | 78.40 | 75.18 | 74.69 | 87.85 | 93.44 | 3.43 | 11.82 |
| 2031 | 79.97 | 76.68 | 76.19 | 89.60 | 95.32 | 3.50 | 12.06 |
| 2032 | 81.57 | 78.21 | 77.71 | 91.40 | 97.22 | 3.57 | 12.06 |
| 2033 | 83.21 | 79.78 | 79.26 | 93.23 | 99.17 | 3.64 | 12.30 |
| 2034 | 84.87 | 81.38 | 80.85 | 95.09 | 101.15 | 3.71 | 12.54 |
| 2035 | 86.57 | 83.00 | 82.47 | 96.99 | 103.17 | 3.79 | 12.80 |
| 2036 | 88.30 | 84.66 | 84.11 | 98.93 | 105.24 | 3.86 | 13.05 |
| 2037+ | +2.0%/yr | +2.0%/yr | +2.0%/yr | +2.0%/yr | +2.0%/yr | +2.0%/yr | +2.0%/yr |

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

(2) Price used when determining 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 Offshore U.K. & Norway reserves.

(8) Prices for 2021 reflect the company's historical weighted average prices. Prices for 2021 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 | | | |
| 2022 | 0.797 | 1.431 | 1.694 |
| 2023 | 0.797 | 1.456 | 1.694 |
| 2024 | 0.797 | 1.494 | 1.701 |
| 2025 | 0.797 | 1.494 | 1.701 |
| 2026 | 0.797 | 1.494 | 1.701 |
| 2027+ | 0.797 | 1.494 | 1.701 |

### 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 2021 audited Consolidated Financial Statements and the MD&A should be consulted for information on income taxes at the corporate entity level.

## Additional Information Relating to Reserves Data

**Future Development Costs**[1]
as at December 31, 2021
(forecast prices and costs)

| ($ millions) | 2022 | 2023 | 2024 | 2025 | 2026 | Remainder | Total | Discounted at 10% |
|---|---|---|---|---|---|---|---|---|
| ***Proved*** | | | | | | | | |
| Mining | 2 585 | 2 810 | 2 628 | 2 266 | 2 328 | 17 256 | 29 874 | 17 377 |
| In Situ | 1 040 | 661 | 579 | 375 | 692 | 17 997 | 21 343 | 8 069 |
| E&P Canada | 299 | 47 | 60 | 102 | 25 | 91 | 623 | 507 |
| Total Canada | 3 923 | 3 518 | 3 267 | 2 743 | 3 045 | 35 344 | 51 840 | 25 953 |
| Offshore U.K. & Norway | 91 | 4 | 8 | 4 | 4 | 74 | 186 | 130 |
| **Total Proved** | **4 014** | **3 522** | **3 275** | **2 747** | **3 049** | **35 418** | **52 026** | **26 083** |
| ***Proved Plus Probable*** | | | | | | | | |
| Mining | 2 745 | 2 982 | 2 796 | 2 404 | 2 478 | 26 731 | 40 136 | 20 148 |
| In Situ | 829 | 612 | 698 | 481 | 490 | 50 276 | 53 385 | 9 000 |
| E&P Canada | 299 | 96 | 144 | 184 | 134 | 270 | 1 126 | 820 |
| Total Canada | 3 873 | 3 690 | 3 637 | 3 069 | 3 101 | 77 277 | 94 647 | 29 968 |
| Offshore U.K. & Norway | 91 | 4 | 8 | 4 | 4 | 96 | 207 | 134 |
| **Total Proved Plus Probable** | **3 964** | **3 694** | **3 646** | **3 073** | **3 106** | **77 372** | **94 854** | **30 102** |

(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 2022 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 ALE at Terra Nova, which are expected to be partially reimbursed by government, and development drilling at Hebron and Hibernia.
- For E&P International, development drilling at Buzzard, Fenja and Oda.

Future development costs disclosed above are associated with reserves as evaluated by GLJ and are subject to change based on many factors, including economic conditions. Management currently believes that internally generated cash flows, existing and future credit facilities, issuing commercial paper and, 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 to some degree depending upon the funding sources utilized. Suncor does not anticipate that interest expense or other funding costs on their own would make development of any property uneconomic.

### Abandonment and Reclamation Costs

The company completes an annual review of its consolidated abandonment and reclamation cost estimates. The estimates are based on the anticipated method and extent of restoration, consistent with legal requirements, technological advances and the possible future use of the site.

As at December 31, 2021, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs for its upstream assets to be approximately $13.6 billion (discounted at 10%, approximately $3.0 billion) excluding Refining and Marketing liabilities ($0.2 billion, undiscounted and uninflated). Abandonment and reclamation costs are limited to current disturbances at December 31, 2021, 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,

2021. Suncor estimates that it will incur $1.1 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2022 – $0.3 billion, 2023 – $0.4 billion, 2024 – $0.4 billion), more than 67% 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 operations include costs related to the reclamation of disturbed land from oil sands mining activities, future mining disturbances, the treatment of legacy oil sands tailings, the decommissioning of oil sands 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. Key abandonment liabilities are associated with 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 $32.7 billion (inflated and undiscounted) has been deducted as abandonment and reclamation costs in estimating the future net revenues from proved plus probable reserves, including $30.2 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)

| | 2019 | | 2020 | | **2021** | |
|---|---|---|---|---|---|---|
| | First Attributed | Total as at December 31, 2019 | First Attributed | Total as at December 31, 2020 | **First Attributed** | **Total as at December 31, 2021** |
| **SCO** (mmbbls) | | | | | | |
| Mining | — | — | 297 | 297 | **—** | **295** |
| In Situ | 53 | 627 | — | 746 | **2** | **715** |
| **Total SCO** | 53 | 627 | 297 | 1 042 | **2** | **1 010** |
| **Bitumen** (mmbbls) | | | | | | |
| Mining | — | — | — | — | **—** | **—** |
| In Situ | 52 | 679 | — | 523 | **1** | **478** |
| **Total Bitumen** | 52 | 679 | — | 523 | **1** | **478** |
| **Light Crude Oil & Medium Crude Oil** (mmbbls) | | | | | | |
| E&P Canada | 2 | 16 | 4 | 18 | **—** | **13** |
| Offshore U.K. & Norway | 1 | 8 | 1 | 8 | **1** | **7** |
| **Total Light Crude Oil & Medium Crude Oil** | 3 | 24 | 6 | 25 | **1** | **20** |
| **Heavy Crude Oil** (mmbbls) | | | | | | |
| E&P Canada | — | 28 | — | 15 | **—** | **2** |
| Offshore U.K. & Norway | — | — | — | — | **—** | **—** |
| **Total Heavy Crude Oil** | — | 28 | — | 15 | **—** | **2** |
| **Conventional Natural Gas** (bcfe) | | | | | | |
| E&P Canada | — | — | — | — | **—** | **—** |
| Offshore U.K. & Norway[2] | — | 13 | — | 11 | **—** | **11** |
| **Total Conventional Natural Gas** | — | 13 | — | 11 | **—** | **11** |
| **Total** (mmboe) | 108 | 1 359 | 302 | 1 608 | **3** | **1 513** |

(1) Figures may not add due to rounding.

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

**Gross Probable Undeveloped Reserves**[1]

(forecast prices and costs)

| | 2019 | | 2020 | | **2021** | |
|---|---|---|---|---|---|---|
| | First Attributed | Total as at December 31, 2019 | First Attributed | Total as at December 31, 2020 | **First Attributed** | **Total as at December 31, 2021** |
| **SCO** (mmbbls) | | | | | | |
| Mining | — | 321 | — | 23 | **—** | **23** |
| In Situ | — | 1 070 | 116 | 1 195 | **—** | **1 185** |
| **Total SCO** | — | 1 391 | 116 | 1 218 | **—** | **1 208** |
| **Bitumen** (mmbbls) | | | | | | |
| Mining | — | — | — | — | **—** | **—** |
| In Situ | — | 267 | 24 | 289 | **—** | **283** |
| **Total Bitumen** | — | 267 | 24 | 289 | **—** | **283** |
| **Light Crude Oil & Medium Crude Oil** (mmbbls) | | | | | | |
| E&P Canada | 6 | 96 | 23 | 55 | **8** | **60** |
| Offshore U.K. & Norway | 1 | 8 | — | 3 | **—** | **3** |
| **Total Light Crude Oil & Medium Crude Oil** | 7 | 104 | 24 | 58 | **8** | **63** |
| **Heavy Crude Oil** (mmbbls) | | | | | | |
| E&P Canada | — | 15 | — | 8 | **—** | **2** |
| Offshore U.K. & Norway | — | — | — | — | **—** | **—** |
| **Total Heavy Crude Oil** | — | 15 | — | 8 | **—** | **2** |
| **Conventional Natural Gas** (bcfe) | | | | | | |
| E&P Canada | — | — | — | — | **—** | **—** |
| Offshore U.K. & Norway[2] | — | 15 | — | 3 | **—** | **4** |
| **Total Conventional Natural Gas** | — | 15 | — | 3 | **—** | **4** |
| **Total** (mmboe) | 7 | 1 780 | 163 | 1 573 | **8** | **1 556** |

(1) Figures may not add due to rounding.

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

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

**In Situ**

Undeveloped In Situ reserves, which constitute approximately 79% of Suncor's gross proved undeveloped reserves and 94% 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 uses integrated plans to forecast future proved undeveloped and probable undeveloped reserves development activity.

These detailed plans align current production, processing and pipeline constraints (which, in the case of processing constraints, do not permit Suncor to develop all of its undeveloped In Situ reserves within two years), capital spending commitments and future development for the next 10 years, and are updated and approved annually for internal and external factors affecting planned activity. The economic viability of developing sustaining pads and associated well pairs is tested to ensure that ongoing development is economic as required for reserves assessment.

**Mining**

Undeveloped Mining reserves constitute approximately 19% of Suncor's gross proved undeveloped reserves, and 1% of Suncor's gross probable undeveloped reserves and relate to the Syncrude MLX-W mining area, which is well-delineated by core hole drilling. Further drilling is planned in 2022 for the opening cut area and infill cores along the west pit limit. The Syncrude MLX-W mining area received AER approval in 2019 and remaining approvals were obtained in the first quarter of 2020. Development of the MLX-W mining area was put on hold in 2020; however, construction activities were restarted in 2021. Development of MLX-W consists of typical mine development activities in addition to a bridge over the MacKay River, and will utilize existing ore processing and extraction facilities at Syncrude's Mildred Lake operation. The MLX-W program is expected to sustain bitumen production levels at Mildred Lake after resource depletion at the North Mine. MLX-W reserves will remain as undeveloped until its major components, such as the bridge, are completed.

**E&P**

Undeveloped conventional reserves (light crude oil and medium crude oil, heavy crude oil and natural gas) constitute approximately 2% of Suncor's gross proved undeveloped reserves and approximately 4% of Suncor's gross probable undeveloped reserves and relate to the company's offshore E&P assets, mainly associated with future drilling at Hebron, and under-drilled or undrilled fault blocks related to areas in Hibernia, infill drilling in Oda, and development drilling and startup of the Fenja Project in offshore Norway. Attribution of proved undeveloped and probable undeveloped reserves reflect, where applicable, the respective degrees of certainty with respect to various reservoir parameters, primarily drainage areas and recovery factors. In developing undeveloped conventional reserves, Suncor considers existing facility capacity, capital allocation plans, and remaining reserves availability. Suncor plans to proceed with development of essentially all proved undeveloped reserves within the next three years and with the development of all probable undeveloped reserves within the next five years.

**Properties with no Attributed Reserves**

The following table is a summary of properties to which no reserves are attributed as at December 31, 2021. For lands in which Suncor holds interests in different formations under the same surface area pursuant to separate leases, the area has been counted for each lease.

| Country | Gross hectares | Net hectares |
|---|---|---|
| Canada | 4 358 376 | 3 216 885 |
| Libya | 3 117 800 | 1 422 900 |
| Syria | 345 194 | 345 194 |
| Norway | 185 185 | 54 949 |
| U.K. | 189 334 | 156 580 |
| **Total** | **8 195 889** | **5 196 508** |

Suncor's properties with no attributed reserves include exploration properties in a preliminary phase of evaluation, to discovery areas where tenure to the property is held indefinitely on the basis of hydrocarbon test results, but where economic development is not currently possible or has not yet been sanctioned. Certain properties may be in a relatively mature phase of evaluation, where a significant amount of 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. Refer to the Risk Factors section of this AIF for additional information on risks and uncertainties.

In 2022, Suncor's rights to 85,163 net hectares in Canada, 11,770 net hectares in Norway and nil net hectares in the U.K. are scheduled to expire. The lands expiring in 2022 include approximately 33,024 net hectares in In Situ and 26,922 net hectares in Mining. Substantial portions of expiring lands may have their tenure continued beyond 2022 through the conduct of work programs and/or the payment of prescribed fees to the mineral rights owner.

<u>Work Commitments</u>

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 certain parts of the world, including Libya. Suncor has work commitments primarily for conducting seismic programs and drilling exploration wells. As at December 31, 2021, 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, 2021.

| | 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) | 448.0 | 448.0 | 17.0 | 17.0 | — | — | — | — |
| Newfoundland and Labrador | 74.0 | 16.1 | 26.0 | 10.7 | — | — | — | — |
| Offshore U.K. & Norway | 33.0 | 9.9 | 3.0 | 0.9 | — | — | — | — |
| Other International(5) | — | — | 422.0 | 212.6 | — | — | 6.0 | 6.0 |
| **Total** | **555.0** | **474.0** | **468.0** | **241.2** | **—** | **—** | **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. & Norway wells are offshore.

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

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

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

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

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

For In Situ properties, proved non-producing reserves and probable non-producing reserves, if any, are associated with SAGD well pairs that have typically been drilled within the last three years, yet require further capital for completion and tie in to facilities to bring the wells on-stream. Because this capital is small relative to the cost to drill, complete and tie in a well pair, the associated reserves are considered developed.

Costs Incurred

The table below summarizes the company's costs incurred related to its exploration and development activities for the year ended December 31, 2021.

| ($ millions) | Exploration costs | Proved property acquisition costs | Unproved property acquisition costs | Development costs | Total |
|---|---|---|---|---|---|
| Canada – Mining and In Situ | 15 | — | — | 3 172 | 3 187 |
| Canada – E&P Canada | 1 | — | — | 120 | 121 |
| **Total Canada** | **16** | **—** | **—** | **3 292** | **3 308** |
| Offshore U.K. & Norway | 29 | — | — | 158 | 187 |
| Other International | 6 | — | — | — | 6 |
| **Total** | **51** | **—** | **—** | **3 450** | **3 501** |

**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, 2021.

| | Exploratory wells[1] | | Development wells | |
|---|---|---|---|---|
| Total number of wells completed | Gross | Net | Gross | Net |
| **Canada – Oil Sands** | | | | |
| Oil | — | — | 43.0 | 43.0 |
| Service[2] | — | — | 40.0 | 40.0 |
| Stratigraphic test[3] | 2.0 | 2.0 | 330.0 | 224.4 |
| **Total** | **2.0** | **2.0** | **413.0** | **307.4** |
| **Canada – E&P Canada** | | | | |
| Oil | — | — | 3.0 | 0.6 |
| Dry hole | — | — | — | — |
| Natural gas | — | — | — | — |
| Service[2] | — | — | 2.0 | 0.4 |
| Stratigraphic test | — | — | — | — |
| **Total** | **—** | **—** | **5.0** | **1.0** |
| **Total Canada** | | | | |
| Oil | — | — | 46.0 | 43.6 |
| Dry hole | — | — | — | — |
| Natural gas | — | — | — | — |
| Service[2] | — | — | 42.0 | 40.4 |
| Stratigraphic test | 2.0 | 2.0 | 330.0 | 224.4 |
| **Total** | **2.0** | **2.0** | **418.0** | **308.4** |
| **Offshore U.K. & Norway** | | | | |
| Oil | — | — | — | — |
| Dry hole | — | — | — | — |
| Service[2] | — | — | 1.0 | 0.2 |
| Stratigraphic test | — | — | — | — |
| **Total** | **—** | **—** | **1.0** | **0.2** |

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

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

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

Significant exploration and development activities in 2021 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 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 and planned maintenance activities.
- 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, which was partially reimbursed by government, and drilling activities at Hebron.
- For E&P International, work on the Norwegian Fenja Project.

For significant exploration and development activities expected to occur in 2022 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]

| 2021 | Q1 | Q2 | Q3 | Q4 | Year Ended |
|---|---|---|---|---|---|
| **Canada – Oil Sands** | | | | | |
| **Upgraded product (SCO and diesel) production (mbbls/d)** | | | | | |
| Oil Sands operations | 329.6 | 326.8 | 221.0 | 332.7 | 301.6 |
| Syncrude | 190.3 | 110.4 | 184.5 | 182.3 | 167.0 |
| Total upgraded production | 519.9 | 437.2 | 405.5 | 515.0 | 468.6 |
| **Non-upgraded bitumen production (mbbls/d)** | | | | | |
| Oil Sands operations | 119.5 | 133.2 | 148.8 | 95.4 | 124.9 |
| Fort Hills | 51.2 | 45.3 | 50.8 | 55.5 | 50.7 |
| Total Oil Sands non-upgraded bitumen production | 170.7 | 178.5 | 199.6 | 150.9 | 175.6 |
| **Total production (mbbls/d)** | **690.6** | **615.7** | **605.1** | **665.9** | **644.2** |
| **Netbacks[3][4]** | | | | | |
| Bitumen ($/bbl) | | | | | |
| Average price realized[2] | 42.53 | 50.20 | 59.91 | 62.05 | 53.80 |
| Royalties | (0.83) | (3.65) | (7.99) | (9.50) | (5.53) |
| Production costs | (13.88) | (15.55) | (18.10) | (20.92) | (17.13) |
| ***Netback*** | 27.82 | 31.00 | 33.82 | 31.63 | 31.14 |
| SCO and diesel ($/bbl) | | | | | |
| Average price realized[2] | 65.22 | 76.50 | 80.21 | 89.38 | 77.73 |
| Royalties | (3.10) | (4.01) | (9.33) | (10.64) | (6.75) |
| Production costs | (26.64) | (32.04) | (33.44) | (29.34) | (30.16) |
| ***Netback*** | 35.48 | 40.45 | 37.44 | 49.40 | 40.82 |
| Average Oil Sands Segment ($/bbl) | | | | | |
| Average price realized[2] | 59.32 | 68.68 | 73.78 | 82.20 | 70.96 |
| Royalties | (2.50) | (3.90) | (8.91) | (10.36) | (6.41) |
| Production costs | (23.34) | (27.14) | (28.58) | (27.13) | (26.48) |
| ***Netback*** | 33.48 | 37.64 | 36.29 | 44.71 | 38.07 |
| **Exploration and Production – Light Crude Oil & Medium Crude Oil** | | | | | |
| Exploration and Production Canada (mbbls/d) | 58.0 | 57.5 | 54.4 | 47.6 | 54.4 |
| Exploration and Production Offshore U.K. & Norway (mboe/d) | 37.3 | 26.5 | 39.1 | 29.8 | 33.1 |
| **Total production volumes (mboe/d)** | **95.3** | **84.0** | **93.5** | **77.4** | **87.5** |
| **Netbacks[3][4]** | | | | | |
| Canada – Light Crude Oil & Medium Crude Oil ($/bbl) | | | | | |
| Average price realized[2] | 73.91 | 80.65 | 90.23 | 98.42 | 84.70 |
| Royalties | (9.24) | (13.26) | (11.88) | (14.59) | (12.20) |
| Production costs | (11.27) | (10.27) | (12.87) | (13.42) | (11.74) |
| ***Netback*** | 53.40 | 57.12 | 65.48 | 70.41 | 60.76 |
| Offshore U.K. & Norway – Light Crude Oil & Medium Crude Oil ($/boe)[5] | | | | | |
| Average price realized[2] | 69.51 | 78.82 | 85.29 | 100.14 | 82.16 |
| Production costs | (8.05) | (13.20) | (10.30) | (10.19) | (10.40) |
| ***Netback[4]*** | 61.46 | 65.62 | 74.99 | 89.95 | 71.76 |

(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 is a non-GAAP financial measure. 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, 2021.

| | SCO | Bitumen | Light CrudeOil & Medium Crude Oil |
|---|---|---|---|
| | mbbls/d | mbbls/d | mboe/d |
| Mining – Suncor | 211.6 | — | — |
| Mining – Syncrude | 167.0 | | — |
| Mining – Fort Hills | — | 50.7 | — |
| Firebag | 90.0 | 89.0 | — |
| MacKay River | — | 35.9 | — |
| Buzzard | — | — | 18.7 |
| GEAD | — | — | 8.3 |
| Oda | — | — | 2.7 |
| Hibernia | — | — | 19.8 |
| White Rose | — | — | 5.4 |
| Terra Nova | — | — | — |
| Hebron[2] | — | — | 29.2 |

(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 2022 that are included in the estimates of proved reserves and probable reserves as at December 31, 2021.

| | 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 | 460 | 410 | 186 | 161 | 53 | 48 | — | — | 699 | 619 |
| Probable | 32 | 26 | 5 | 3 | 5 | 5 | — | — | 42 | 34 |
| Proved Plus Probable | 492 | 436 | 191 | 164 | 58 | 53 | — | — | 741 | 653 |
| **Offshore U.K. & Norway** | | | | | | | | | | |
| Proved | — | — | — | — | 21 | 21 | 3 | 3 | 21 | 21 |
| Probable | — | — | — | — | 4 | 4 | 2 | 2 | 4 | 4 |
| Proved Plus Probable | — | — | — | — | 25 | 25 | 5 | 5 | 25 | 25 |
| **Total**[1][2] | | | | | | | | | | |
| Proved | 460 | 410 | 186 | 161 | 73 | 69 | 3 | 3 | 721 | 640 |
| Probable | 32 | 26 | 5 | 3 | 9 | 8 | 2 | 2 | 46 | 38 |
| Proved Plus Probable | 492 | 436 | 191 | 164 | 82 | 77 | 5 | 5 | 767 | 678 |

(1) Figures may not add due to rounding.

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

The following properties each account for approximately 20% or more of total estimated production for 2022.

Proved

- From Millennium and North Steepbank: 191 mbbls/d of SCO, which represents approximately 27% of total estimated production for 2022.
- From Firebag: 170 mbbls/d of SCO and bitumen (111 mbbls/d and 60 mbbls/d, respectively), which represents approximately 24% of total estimated production for 2022.
- From Syncrude: 159 mbbls/d of SCO, which represents approximately 22% of total estimated production for 2022.

Proved Plus Probable

- From Millennium and North Steepbank: 204 mbbls/d of SCO, which represents approximately 27% of total estimated production for 2022.
- From Firebag: 174 mbbls/d of SCO and bitumen (115 mbbls/d and 59 mbbls/d, respectively), which represents approximately 23% of total estimated production for 2022.
- From Syncrude: 173 mbbls/d of SCO from Syncrude, which represents approximately 23% of total estimated production for 2022.

None of the company's light and medium crude oil production associated with its E&P Canada and Offshore U.K. & Norway assets accounts for 20% or more of the total estimated production for 2022.

**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 2021 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2021.

**Tax Horizon**

In 2021, 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 2022.