United States
Securities and Exchange Commission
Washington, D.C. 20549

FORM 40-F

[ ] Registration Statement pursuant to section 12 of the Securities Exchange Act of 1934

[X] Annual report pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2025 Commission File Number: 001-12138

CANADIAN NATURAL RESOURCES LIMITED
(Exact name of Registrant as specified in its charter)

ALBERTA, CANADA
(Province or other jurisdiction of incorporation or organization)
1311
(Primary Standard Industrial Classification Code Numbers)

Not Applicable
(I.R.S. Employer Identification Number (if applicable))

2100, 855-2nd Street S.W., Calgary, Alberta, Canada, T2P 4J8
Telephone: (403) 517-6700
(Address and telephone number of Registrant's principal executive offices)
CT Corporation System, 28 Liberty Street, New York, New York 10005
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be 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, no par value	CNQ	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:

[X] Annual information form [X] Audited annual 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.

2,081,578,000 Common Shares outstanding as of December 31, 2025

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 [X] 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 [X] 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.

Yes [X] No [ ]

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 recover period pursuant to §240.10D-1(b).

[___]

† The term new or revised financial accounting standard refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

This Annual Report on Form 40-F shall be incorporated by reference into, or as an exhibit to, as applicable, the Registrant's Registration Statement on Form F-10 (File No 333-289937) under the Securities Act of 1933, as amended.

PRINCIPAL DOCUMENTS

The following documents have been filed as part of this Annual Report on Form 40-F, starting on the following page:

A. Annual Information Form

Annual Information Form of Canadian Natural Resources Limited ("Canadian Natural") for the year ended December 31, 2025.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2025 and 2024 including the report of independent registered public accounting firm (PCAOB ID 271) with respect thereto.

C. Management's Discussion and Analysis

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2025.

The following document is filed as an exhibit to this Annual Report on Form 40-F and is incorporated by reference herein:

A. Supplementary Oil & Gas Information (Unaudited)

For Canadian Natural's Supplementary Oil & Gas Information (Unaudited) for the year ended December 31, 2025, see Exhibit 99.1 to this Annual Report on Form 40-F.



CANADIAN NATURAL RESOURCES LIMITED

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2025

March 25, 2026

Annual Information Form

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Definitions and Abbreviations

ADR	abandonment, decommissioning and reclamation costs
AOSP	Athabasca Oil Sands Project
API	specific gravity measured in degrees on the American Petroleum Institute scale
ARO	asset retirement obligations
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
bitumen	naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons that are too heavy or thick to flow at reservoir conditions, and recoverable at economic rates using thermal in-situ recovery or conventional truck and shovel (mining) methods
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
C$ or $	Canadian dollars
"Canadian Natural Resources Limited", "Canadian Natural", "Company", "Corporation"	Canadian Natural Resources Limited and includes, where applicable, reference to subsidiaries of and partnership interests held by Canadian Natural Resources Limited and its subsidiaries
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
crude oil	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, thermal bitumen, mining bitumen and synthetic crude oil
CSS	Cyclic Steam Stimulation
development well	well drilled inside the established limits of an oil or gas reservoir or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive
dry well	well that proves to be incapable of producing either crude oil or natural gas in sufficient quantities to justify completion
EOR	Enhanced Oil Recovery
exploratory well	well that is not a development well, a service well, or a stratigraphic test well
extension well	well that is drilled to test if a known reservoir extends beyond what had previously been believed to be the outer reservoir perimeter
fee title interest	absolute ownership of legal title to mineral lands, subject to conditional interests that may have been granted from the title, such as petroleum and natural gas leases
FPSO	Floating Production, Storage and Offloading vessel
GHG	greenhouse gas
gross acres	total number of acres in which the Company has a working interest or fee title interest
gross wells	total number of wells in which the Company has a working interest
Horizon	Horizon Oil Sands
IFRS Accounting Standards	International Financial Reporting Standards as issued by the International Accounting Standards Board
Mbbl	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MD&A	Management's Discussion and Analysis

MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MM$	million Canadian dollars
MOU	Memorandum of Understanding between the Government of Canada and the Government of Alberta dated November 27, 2025
NGLs	natural gas liquids
net acres	gross acres multiplied by the percentage working interest or fee title interest therein owned by the Company
net wells	gross wells multiplied by the percentage working interest therein owned by the Company
NYSE	New York Stock Exchange
OPEC+	Organization of Petroleum Exporting Countries Plus
Paris Agreement	The Paris Agreement is an agreement within the United Nations Framework Convention on Climate Change, on climate change mitigation, adaption, and finance signed in 2016.
productive well	exploratory, development or extension well that is not dry
proved property	property or part of a property to which reserves have been specifically attributed
PRT	Petroleum Revenue Tax
Quest	Quest Carbon Capture and Storage ("CCS") project
SAGD	Steam-Assisted Gravity Drainage
SCO	synthetic crude oil, a mixture of liquid hydrocarbons derived by either partially or fully upgrading bitumen
SEC	United States Securities and Exchange Commission
service well	well drilled or completed for the purpose of supporting production in an existing field and drilled for the specific purposes of gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion
stratigraphic test well	drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition and ordinarily drilled without the intention of being completed for hydrocarbon production
TMX	Trans Mountain Expansion pipeline
TSX	Toronto Stock Exchange
UK	United Kingdom
unproved property	property or part of a property to which no reserves have been specifically attributed
US	United States
working interest	interest held by the Company in a crude oil or natural gas property, which interest normally bears its proportionate share of the costs of exploration, development, and operation as well as any royalties or other production burdens

Advisory

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company" or "Canadian Natural") in this Annual Information Form ("AIF") or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to the Company's strategy or strategic focus, capital budget, expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, abandonment expenditures, income tax expenses, and other targets provided throughout this AIF constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to the Company's assets at Horizon, AOSP, the Primrose thermal oil projects, the Pelican Lake water and polymer flood projects, the Kirby, Jackfish and Pike thermal oil sands projects, the operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or NGLs that the Company may be reliant upon to transport its products to market, the decommissioning and abandonment of certain of the Company's assets and the timing thereof, the development and deployment of technology and technological innovations, the assumption of operations at processing facilities, the "2026 Activity" section of this AIF with respect to budgeted capital expenditures for 2026, targeted decommissioning activities in International and the timing thereof, the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long-term, the materiality of the impact of litigation and tax interpretations on the Company's results, any targeted payouts pursuant to the Company's free cash flow allocation policy, and the Company's acquisitions, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of the actions of OPEC+, the impact of conflicts in the Middle East, in Ukraine and in Venezuela, the restriction or disruption of global trade routes, the impact of changes to US economic policy, increased inflation, and the risk of decreased economic activity resulting from a global recession) which may impact, among other things, demand and supply for, and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil, natural gas and NGLs prices; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; changes and uncertainty in the international trade environment, including with respect to tariffs, export restrictions, embargoes, and key trade agreements (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased or expanded); uncertainty in the regulatory framework governing GHG emissions including, among other things, financial and other support from various levels of government for climate related initiatives and potential emissions or production caps, and the implementation of the MOU; political uncertainty, including changes in government, actions of or against terrorists, insurgent groups or other conflict including conflict between states; the Company's ability to prevent and recover from a cyberattack and other cyber-related crimes and incidents; industry capacity; the Company's ability to implement its business strategy, including exploration and development activities; the impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; the Company's ability to complete capital programs; the Company's ability to secure adequate transportation for its products; unexpected disruptions or delays in mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for, and production and sale of, crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels, the timing and success of integrating the business and operations of acquired companies and

assets, including the acquisition of the remaining 10% interest in the AOSP mines and other acquisitions that occurred in 2025; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; changes to future abandonment and decommissioning costs; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety, competition, environmental laws and regulations, and the impact of climate change initiatives on capital expenditures and production expenses); interpretations of applicable tax and competition laws and regulations; asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short-, medium- and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the impact of legal proceedings to which the Company is a party; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial, state, and local laws and regulations such as restrictions on production or emissions, the imposition of tariffs, export restrictions or embargoes on the Company's products (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased or expanded), changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations (including the implementation of the MOU). Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available. For additional information refer to the "Risk Factors" section of this AIF.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this AIF could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements in this AIF, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

SPECIAL NOTE REGARDING CURRENCY, FINANCIAL INFORMATION, PRODUCTION AND RESERVES

In this AIF, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are presented on a "before royalties" or "company gross" basis and realized prices are net of blending and feedstock costs and exclude the effects of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent or BOE. A BOE is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

The Company's audited consolidated financial statements and annual MD&A for the most recently completed fiscal year ended December 31, 2025, dated March 4, 2026, are herein incorporated by reference, and certain information included in this AIF, has been prepared in accordance with IFRS Accounting Standards. In the Company's annual MD&A for the year ended December 31, 2025, all references to synthetic crude oil in relation to the Oil Sands Mining and Upgrading segment, including realized pricing, production volumes, sales volumes, and netback calculations, are presented inclusive of mining bitumen. For details refer to the "Definitions and Abbreviations" section of the annual MD&A. Unless otherwise noted in this AIF, synthetic crude oil and mining bitumen are reported separately.

For the year ended December 31, 2025, the Company retained Independent Qualified Reserves Evaluators ("IQRE"), Sproule International Limited ("Sproule ERCE") and GLJ Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves with an effective date of December 31, 2025 and a preparation date of February 9, 2026. Sproule ERCE evaluated and reviewed the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, thermal bitumen, natural gas and NGLs reserves. GLJ evaluated the Oil Sands Mining and Upgrading mining bitumen and SCO reserves. The evaluations and reviews were conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual report on Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's 2025 Annual Report, which is incorporated herein by reference.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This AIF includes references to non-GAAP and other financial measures as defined by National Instrument 52-112 - Non-GAAP and Other Financial Measures Disclosure ("NI 52-112"). These financial measures, including "adjusted net earnings from operations", "adjusted funds flow", "netback", "realized price", "net capital expenditures", "long-term debt, net" and "free cash flow", are used by the Company to evaluate its financial performance, financial position and cash flow. These financial measures are not defined by IFRS Accounting Standards and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the Company's financial statements, as applicable, as an indication of the Company's performance. Descriptions of and reconciliations to the most directly comparable financial measure for "adjusted net earnings from operations", "adjusted funds flow", "netback", "realized price", "net capital expenditures" and "long-term debt, net", are provided in the "Non-GAAP and Other Financial Measures" section of the Company's annual MD&A for the year ended December 31, 2025, dated March 4, 2026, and are incorporated by reference herein. "Free cash flow" is a non-GAAP financial measure. The Company considers free cash flow a key measure in demonstrating the Company's ability to generate cash flow to fund future growth through capital investment, to repay debt and to pay returns to shareholders through dividends and share repurchases pursuant to its free cash flow allocation policy. Free cash flow is calculated as adjusted funds flow less dividends on common shares, net capital expenditures and abandonment expenditures.

SPECIAL NOTE REGARDING COMMON SHARE SPLIT AND COMPARATIVE FIGURES

At the Company's Annual and Special Meeting held on May 2, 2024, shareholders passed a Special Resolution approving a two for one common share split effective for shareholders of record as of market close on June 3, 2024. On June 10, 2024, shareholders of record received one additional share for every one common share held, with common shares trading on a split-adjusted basis beginning June 11, 2024. Common share, per common share, dividend, and stock option amounts for periods prior to the two for one common share split have been updated to reflect the common share split.

SPECIAL NOTE REGARDING AMENDMENTS TO THE COMPETITION ACT (CANADA)

On June 20, 2024, amendments to the Competition Act (Canada) came into force with the adoption of Bill C-59, An Act to Implement Certain Provisions of the Fall Economic Statement, which impacted environmental and climate disclosures by businesses. As a result of these amendments, certain public representations by a business regarding the benefits of the work it is doing to protect or restore the environment or mitigate the environmental and ecological causes or effects of climate change may violate the Competition Act's deceptive marketing practices provisions. These amendments include substantial financial penalties and, effective June 20, 2025, a private right of action which will permit private parties to seek an order from the Competition Tribunal under the deceptive marketing practices provisions. Subsequently, on November 4, 2025, the federal government tabled the 2025 Budget, which proposed further amendments to the Competition Act, namely removing the requirement that businesses substantiate their environmental representations about a business or business activity based on an internationally recognized methodology, and eliminating private rights of action under the revised business-activity greenwashing provision. Uncertainty surrounding the interpretation and enforcement of this legislation, which includes the status of any proposed or future amendments, may expose the Company to increased litigation and financial penalties, the outcome and impacts of which can be difficult to assess or quantify and may have a material adverse effect on the Company's business, reputation, financial condition, and results.

Corporate Structure

Canadian Natural Resources Limited was incorporated under the laws of the Province of British Columbia on November 7, 1973 as AEX Minerals Corporation (N.P.L.) and, on December 5, 1975, changed its name to Canadian Natural Resources Limited. Canadian Natural was continued under the Companies Act (Alberta) on January 6, 1982 and was further continued under the Business Corporations Act (Alberta) on November 6, 1985. Since that time, the Company has completed a number of transactions which have resulted in amalgamations, arrangements and amendments to constating documents, none of which have resulted in material changes thereto.

At the Company's Annual and Special Meeting held on May 2, 2024, shareholders passed a Special Resolution approving an amendment to the Company's Articles of Amalgamation to subdivide the issued and outstanding common shares on a two-for-one basis. Articles of Amendment were subsequently filed on May 22, 2024. (Further details are disclosed under "Description of Capital Structure - Common Shares" in this AIF.)

In the last ten years, the Company has amalgamated pursuant to the Business Corporations Act (Alberta) under the name Canadian Natural Resources Limited with the following:

Amalgamated Company:	**Date**
EOG Resources Canada Inc.	January 1, 2015
Laricina Energy Ltd.	January 1, 2019
CNRL Upgrading Limited	October 1, 2020
Painted Pony Energy Ltd.	January 1, 2021
Storm Resources Ltd.; Storm Gas Resource Corp.; CNR Montney Ltd.	January 1, 2022
Horizon Construction Management Ltd.	January 1, 2023

The Company's current head and registered office is located in Calgary, Alberta, Canada at 2100, 855 - 2nd Street S.W., T2P 4J8. In June 2026, the Company is relocating its head and registered office to 400 - 4th Avenue S.W., Calgary, AB, T2P 0J4.

The main operating subsidiaries and partnerships of the Company, percentage of voting securities owned either directly or indirectly, and their jurisdictions of incorporation are as follows:

	Jurisdiction of Incorporation	**% Ownership**
Subsidiary:		
Canadian Natural Upgrading Limited	Alberta	100
CanNat Energy Inc.	Delaware	100
CanNat Liquids Marketing Limited	Alberta	100
CNR International (U.K.) Developments Limited	England	100
CNR International (U.K.) Limited	England	100
CNR International (Côte d'Ivoire) SARL	Côte d'Ivoire	100
CNR International (South Africa) Limited	Alberta	100
CNR (Redwater) Limited	Alberta	100
Sukunka Natural Resources Inc.	Alberta	100
CNR Petro Resources Limited	Alberta	100
Partnership:		
CNR Montney Partnership	Alberta	100

Canadian Natural, as the managing partner, and CNR Petro Resources Limited, are partners of CNR Montney Partnership, a general partnership.

In the ordinary course of business, Canadian Natural restructures its subsidiaries and partnerships to maintain efficient operations.

The audited consolidated financial statements of Canadian Natural include the accoun ts of the Company and all of its subsidiaries and wholly-owned partnerships as well as certain of the Company's activities which are conducted through joint arrangements.

General Development of the Business

2023

The Company approved the final investment decision to proceed with the Pike 1 thermal in situ project as part of its 2023 capital budget. Drilling and pipeline development in support of the Pike 1 project commenced in late 2024 with the Company drilling two SAGD pads in 2025, which are tied into the existing Jackfish facilities. The first of the two pads began production in late 2025 with the second targeted to come on production in the second quarter of 2026 and are expected to keep the Jackfish plants at full capacity. In December 2023, the Company approved the decision to proceed with the Naphtha Recovery Unit Tailings Treatment project at Horizon, for a total capital investment of approximately $357 million. The project commenced in 2024 and is expected to be mechanically complete in the third quarter of 2027.

The Company made a number of adjustments to its debt financing plan in 2023. In June 2023, the Company extended its $2,425 million revolving syndicated credit facility by three years to mature in June 2027. In July 2023, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, both of which expired in August 2025, replacing the Company's previously filed base shelf prospectuses that would have expired in August 2023. In September 2023, the Company extended its $500 million revolving credit facility to mature in February 2025. In November 2023, the Company also repaid $405 million of 1.45% medium-term notes.

In November 2023, the Company announced a number of senior management promotions positioning the Company to continue the strategic development of its long life, low decline assets and low capital exposure assets and the creation of value for shareholders into the future.

2024

At the Company's Annual and Special Meeting held on May 2, 2024, shareholders passed a special resolution approving a two for one common share split effective for shareholders of record as of market close on June 3, 2024. On June 10, 2024, shareholders of record received one additional share for every one common share held, with common shares trading on a split-adjusted basis beginning June 11, 2024.

During 2024, the Company increased its contracted crude oil transportation capacity to 256,500 bbl/d, expanding its committed capacity to Canada's West Coast and to the United States Gulf Coast ("USGC"). After the TMX was successfully commissioned in the second quarter of 2024, the Company increased its capacity on the TMX by 75,000 bbl/d to a total of 169,000 bbl/d. The Company also increased its capacity on the Flanagan South pipeline in 2024 by an additional 55,000 bbl/d for a total of 77,500 bbl/d, further expanding the Company's heavy oil diversification and market access to the USGC. The Company also has committed capacity of 10,000 bbl/d on the Keystone Base pipeline, with direct access to the USGC.

In December 2024, the Company completed acquisitions of Chevron Canada Limited's ("Chevron") Alberta assets, which included Chevron's 20% interest in AOSP and a 70% operated interest in light crude oil and liquids-rich Duvernay assets. As a result of these acquisitions, the Company owned 90% of AOSP, which included the Muskeg River and Jackpine mines, the Scotford Upgrader and Quest. The acquisitions also included various working interests in a number of other non-producing oil sands leases. The aggregate consideration for these assets was US$6.5 billion, subject to closing adjustments.

The Company also made a number of adjustments to its debt financing plan in 2024. The Company extended the maturity of its $2,425 million revolving syndicated credit facility from June 2025 to June 2028 and extended its $500 million revolving credit facility from February 2025 to February 2026. The Company repaid $320 million of 3.55% medium-term notes and US$500 million of 3.80% of US dollar debt securities. In connection with the acquisition of Chevron's Alberta assets, the Company entered into a $4,000 million non-revolving term credit facility maturing December 2027. In December, the Company also issued $500 million of 4.15% medium-term notes due December 2031 at $99.836 per note, US$750 million of 5.00% notes due December 2029 at US$99.968 per note and US$750 million of 5.40% notes due December 2034 at US$99.837 per note.

In 2024, the Company continued to renew its senior management team with additional promotions positioning the Company to continue its strategic program for the creation of value for shareholders into the future.

2025

During 2025, the Company closed an acquisition of lands and production in the Palliser Block located in southern Alberta, which added production volumes of approximately 50,000 BOE/d, including 20,000 bbl/d of Mannville light crude oil and NGLs. This acquisition also included approximately 1.1 million net acres of land, with identified light crude oil inventory for approximately 850 locations. The Company also closed an acquisition of liquids-rich Montney assets located in the Grande Prairie area of northern Alberta with production from the acquisition of approximately 32,000 BOE/d, including 12,500 bbl/d of NGLs. Finally, the Company completed the AOSP asset swap with Shell Canada Limited and affiliates ("Shell"). As a result of the transaction, the Company acquired the remaining 10% interest in the AOSP mines, associated reserves, and additional working interests in a number of other non-producing oil sands leases in exchange for a 10% working interest in the non-operated Scotford Upgrader and Quest. The Company now owns and operates 100% of the AOSP mines, and retains a non-operated 80% working interest in the Scotford Upgrader and Quest.

During 2025, the Company entered into a long-term natural gas supply agreement to supply 140,000 MMBtu/d of natural gas for a term of 15 years, with delivery anticipated to begin in 2030 as all conditions precedent have been waived by the counterparty. Under the terms of the agreement, the Company will deliver natural gas to its counterparty in Illinois, USA and receive a Japan-Korea Marker index price less deductions for transportation and liquefaction.

The Company also made a number of adjustments to its debt financing plan in 2025. The Company extended its $500 million revolving credit facility from February 2026 to June 2027. The Company increased its $2,425 million revolving syndicated facility to $2,565 million, and extended $2,425 million originally due June 2027 to June 2029. The remaining $140 million outstanding under this facility will mature in June 2027. The Company repaid US$600 million of 3.90% US dollar debt securities and US$600 million of 2.05% US dollar debt securities. In August 2025, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$4,500 million of debt securities in the United States, both of which expire in September 2027, replacing the Company's previously filed base shelf prospectuses that would have expired in August 2025. In October 2025, the Company completed the exchange of US$747 million of the outstanding restricted 5.00% US dollar debt securities due December 2029 and US$750 million of the outstanding restricted 5.40% US dollar debt securities due December 2034. The exchanged notes were not subject to transfer restrictions and did not impact the Company's level of indebtedness. In December 2025, the Company issued $550 million of 3.30% medium-term notes due December 2028 at $99.887 per note, $550 million of 3.75% medium-term notes due February 2031 at $99.781 per note and $550 million of 4.55% medium-term notes due February 2036 at $99.700 per note.

In 2025, the Company continued to renew its senior management team with additional promotions positioning the Company to continue its strategic program for the creation of value for shareholders into the future.

Description of the Business

Canadian Natural is a Canadian based senior independent energy company engaged in the acquisition, exploration, development, production, marketing and sale of crude oil, natural gas and NGLs. The Company's principal core regions of operations are western Canada, the UK sector of the North Sea and Offshore Africa.

The Company operates and maintains a large working interest in a majority of the prospects in which it participates. The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value on a per common share basis through the economic and sustainable development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives and its commitments to environmental stewardship and safety excellence.

The Company has a full complement of management, technical and support staff to pursue these objectives. As of December 31, 2025, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	3,068
North America, Oil Sands Mining and Upgrading	4,970
North Sea and Offshore Africa	302
Corporate	2,410
Total Company	10,750

Operational discipline, together with safe, effective and efficient operations and cost control, are fundamental to the Company. By consistently managing costs throughout all industry cycles, the Company believes it will achieve continued growth. The Company achieves safe operations that are effective and efficient and controls cost by developing area knowledge and by maintaining high working interests and operator status in its properties. The Company has grown through a combination of internal growth and strategic acquisitions. Acquisitions are made with a view to either entering new core regions or increasing the Company's presence in existing core regions.

The Company's business approach is to maintain large project inventories and production diversification among each of its products: SCO, mining bitumen, natural gas, light and medium crude oil and NGLs, thermal bitumen, primary heavy crude oil and Pelican Lake heavy crude oil. The Company's large diversified project portfolio enables the effective allocation of capital to higher return opportunities, which together provide complementary infrastructure and balance throughout the business cycle. SCO from the oil sands mining and upgrading operations in northern Alberta accounted for 36% of 2025 annual production[(1)]. Natural gas, primarily produced in Alberta, British Columbia and Saskatchewan, accounted for 27% of 2025 annual production. Light and medium crude oil and NGLs represented 11% of 2025 annual production, and were produced from Alberta, British Columbia, Saskatchewan and Manitoba, as well as from the Company's North Sea and Offshore Africa operations. Thermal bitumen, which accounted for 17% of 2025 annual production, primary heavy crude oil, which accounted for 6% of 2025 annual production, and Pelican Lake heavy crude oil, which accounted for 3% of 2025 annual production, were also produced from Alberta and Saskatchewan. The Company's Midstream assets, primarily comprised of two operated pipeline systems (ECHO and Pelican Lake), and a 50% working interest in an 84 megawatt cogeneration plant at Primrose, provide cost effective infrastructure supporting the Company's heavy crude oil and thermal bitumen operations. Midstream assets also include a 50% equity interest in the North West Redwater Partnership.

The Company's Canadian crude oil production is marketed to purchasers located in Canada and other international destinations. Purchasers that take delivery in Canada may subsequently export those products to other international destinations using their own transportation. The Company has contracted pipeline capacity for approximately 22% of its liquids production. This includes contracted capacity on the Flanagan South pipeline (77,500 bbl/d) and the Keystone Base pipeline (10,000 bbl/d). The Company also has contracted capacity on TMX (169,000 bbl/d) which gives the Company the option to sell either to customers in Western Canada or to international markets. The Company also markets natural gas directly to purchasers in both Canada and other international markets. Purchasers that take delivery in Canada may subsequently export those products to other international destinations using their own transportation. Natural gas is distributed to customers in Canada via the TC Canadian Mainline and other pipelines such as the Enbridge Westcoast system. NGLs are marketed to purchasers located in Canada, some of whom may export those products to other international destinations. The Company's offshore production from its North Sea and West African operations is sold primarily into European markets.

(1) Annual production calculated on a BOE basis. For the purposes of this calculation, SCO includes mining bitumen.

A. ENVIRONMENTAL MATTERS

Environmental Management Approach

The Company has a Corporate Statement on Environmental Management which affirms that environmental stewardship is a fundamental value of the Company. This commitment ensures the Company, as well as its employees and contractors, carry out all business activities in compliance with applicable regional, national and international regulations and industry standards. The Company's oil sands mining and the UK divisions also conduct operations in accordance with Environmental Management Systems that are audited by independent third parties. As part of the Company's corporate governance mandate, the Company's environmental specialists track performance to numerous environmental performance indicators in its domestic and international operations, and regularly report to the senior management of the Company, which in turn reports on environmental matters directly to the Health, Safety, Asset Integrity and Environmental Committee of the Board of Directors. This Committee's mandate also includes oversight of the Company's policies and programs related to climate change and GHG emissions, social/community matters and stakeholder relations.

The Company regularly engages with and submits to inspections by the various government regulatory authoriti es in each of the regions where the Company operates. The Company's environmental risk management strategy includes working constructively with legislators and regulators to ensure that any new or revised legislation, regulations or policies properly reflect a balanced approach to sustainable development. The Company has processes in place and is committed to complying with all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. In Canada, these requirements apply to all operators in the crude oil and natural gas industry and it is not anticipated that the Company's competitive position within the industry will be adversely affected by changes in applicable legislation; however, there are no assurances that future environmental laws and regulations will not have a material effect on the Company's business, financial condition and results of operations.

The Company has internal procedures designed to ensure that the environmental aspects of new acquisitions and developments are taken into account prior to proceeding. The Company's Environmental Management Plan (the "Plan") along with the Company's operating guidelines and strategies are intended to reduce the environmental impact of operations while meeting: regulatory requirements; regional management frameworks for air quality and emissions, ground and surface water, and biodiversity; industry operating standards and guidelines; and internal corporate standards. Adequate and proper training of, and diligent execution by, the Company's operators and contractors is key to the effectiveness of the Company's environmental management programs and supports efforts to reduce the Company's environmental footprint.

Canada

The Company continues to invest in people, facilities and infrastructure, as well as new and proven technologies, to recover and process crude oil and natural gas resources efficiently and in an environmentally responsible manner. As a part of the Plan, the Company has implemented a number of programs intended to reduce its environmental footprint including: various programs designed to reduce GHG and methane emissions; assessment of impacts of the Company's operations, together with implementation of avoidance and mitigation programs that seek to maintain biodiversity for terrestrial and aquatic systems and high value ecosystems; the continued review and evaluation of new technologies designed to reduce environmental impacts from operations; and optimization programs that seek to improve efficiencies at the Company's facilities.

The Company, through industry associations, is working with Canadian legislators and regulators as they develop and implement laws and regulations to properly reflect a balanced approach to sustainable development, such as programs to support industry investments in environmental performance improvement and emissions reduction.

Bill C-59, which received royal assent in June 2024, created among other things, a new investment tax credit ("ITC") to support investment in eligible carbon capture, utilization and storage ("CCUS") projects by providing a refundable ITC of up to 50% on carbon capture equipment and 37.5% on qualified carbon transportation, storage or usage equipment from 2022 to 2030, with these ITC rates being halved from 2031 to 2040 and fully phased out after 2040. In the 2025 Budget released on November 4, 2025, the federal government announced its intention to extend the availability of the CCUS ITCs by five years so that the full rates will apply to eligible expenditures from 2022 to 2035. The Government of Alberta also established the Alberta Carbon Capture Incentive Program in 2023, which provides a 12% grant on eligible capital costs for CCUS projects.

Air quality programs are an essential part of the Company's environmental work plan and are operated within all industry and regulatory standards and guidelines. The Company also participates in air quality monitoring through regional organizations. Data collected through these regional air shed monitoring programs is used by government agencies to develop regional management programs and frameworks.

The Company has a well-established venting and solution gas conservation program at its facilities and incorporates future conservation opportunities into new projects and facilities. As part of the Company's initiatives to optimize and improve fuel gas efficiency, the Company also monitors compressor fleet performance and has ongoing methane reduction programs for pneumatic devices.

As part of the Company's water management strategy, the Company has water management programs designed to improve recycle rates and reduce freshwater use. These programs include the Hydraulic Fracturing Operating Practices developed by the Canadian Association of Petroleum Producers, which are intended to support a responsible approach to hydraulic fracturing and water management.

The Company has implemented programs for well abandonment and decommissioning that allow for the progressive reclamation of large contiguous areas of land. In 2025, the Company's environmental liability reduction program completed the decommissioning of 2,753 inactive wells and has 12,620 sites progressing towards reclamation certification. In addition, for 2025, the Company received 1,205 reclamation certificates representing 2,188 hectares of land. Since 2021, the Company has decommissioned 12,969 inactive wells and received 5,393 reclamation certificates representing 10,556 hectares of reclaimed land. The Company also conducted additional decommissioning and clean up activities at various active and inactive facilities to address environmental liabilities at its operating sites.

In addition, the Company has comprehensive programs in place for: (i) tailings management in its oil sands mining operations to minimize fine tailings and support reclamation; (ii) monitoring programs to assess changes to biodiversity, wildlife and fisheries, in order to manage construction and operational effects and to assess reclamation success; (iii) groundwater monitoring for all thermal in situ and mine operations; (iv) an active spill prevention and management program; and (v) an internal environmental management system for conformance audit and inspection of operating facilities. The Company also participates in the Oil Sands Monitoring Program, a joint program sponsored by the federal government and the Government of Alberta, which supports the regional monitoring of air, surface water, groundwater, wetlands and biodiversity.

International

In 2025, the Company continued decommissioning activities in the North Sea, including cessation of production at the Ninian South platform and the associated subsea fields. Stakeholder engagement was completed ahead of formally submitting the Ninian South Decommissioning Program for regulatory approval in December 2025. Decommissioning activities will continue at the Ninian Hub throughout 2026. Additionally, based on current and forecasted economic conditions, including commodity prices and market egress, the Company determined that the T-Block assets were no longer economically viable. Cessation of production has been accelerated to the first quarter of 2027 and associated crude oil reserves were de-booked.

B. REGULATORY MATTERS

The Company's business is subject to regulations and rules developed by legislation and governmental agencies. Certain key regulatory regimes impacting the Company's operations are summarized in the following paragraphs.

Canada

Petroleum and Natural Gas Leases

The crude oil and natural gas industry in Canada operates under legislation and regulations that govern exploration, development, production, refining, marketing, transportation, prevention of waste and other activities.

The Company's Canadian properties are primarily located in Alberta, British Columbia, Saskatchewan, and Manitoba. Most of these properties are held under leases/licences obtained from the applicable federal or provincial governments, which give the holder the right to explore for and produce bitumen, crude oil, natural gas and NGLs. The remainder of the properties are held under freehold (private ownership) leases.

Conventional petroleum and natural gas leases issued by the provinces of Alberta, Saskatchewan and Manitoba have a primary term from two to five years, and British Columbia leases/licences presently have a primary term of up to ten years. Those leases that are producing or are capable of producing at the end of the primary term will "continue" for the productive life of the lease.

An Alberta oil sands primary lease is issued for fifteen years. Primary oil sands leases that are designated as "producing" will continue for as long as the minimum level of production is maintained while those designated as "non-producing" and not meeting the required minimum level of production can be continued by payment of escalating rentals.

The provincial governments regulate the production of crude oil, natural gas and NGLs. Government royalties are payable on crude oil, natural gas and NGLs produced from leases owned by the province. The royalties are determined by regulation and are generally calculated as a percentage of production adjusted by a number of different factors including selling prices, production levels, recovery methods, transportation and processing costs, location and date of discovery.

Royalties

Alberta royalties on oil sands projects are based on a sliding scale ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout, depending on benchmark crude oil pricing.

Effective January 1, 2017, the Alberta government adopted the Modernized Royalty Framework ("MRF") for conventional crude oil, natural gas and NGLs royalties. As a result, Alberta currently has a parallel royalty regime system with the previous Alberta Royalty Framework ("ARF") continuing to apply until December 31, 2026 to wells drilled prior to July 13, 2016 and the MRF applying to wells drilled on or after January 1, 2017. For wells drilled between July 13, 2016 and December 31, 2016 producers may opt in to the MRF if certain criteria are met. Under the MRF, conventional royalty rates range from 5% to 36% for natural gas and NGLs and 5% to 40% for crude oil.

On May 19, 2022, the Government of British Columbia announced a new royalty framework, which will come into effect on January 1, 2027. The new framework will replace previous drilling incentive programs with a revenue minus costs model similar to other Canadian jurisdictions. New wells will pay a flat royalty rate of 5% until the capital spent on drilling and completions is recovered and then a price sensitive royalty rate between 5% and 40% will apply and vary based on commodity type. Details of

certain cost allowances and reference prices remain to be finalized by the BC government through consultation with stakeholders.

Taxation

The Company was subject to federal and provincial income taxes in Canada at a combined rate of approximately 23.14% in 2025. The Company is also subject to federal legislation implementing a 2% tax on repurchases of equity in 2025. The 2% tax is applicable to repurchases and issuances of equity that occur after December 31, 2023.

Abandonment and Reclamation – Liability Management

The Alberta Energy Regulator ("AER") established a Liability Management Framework (the "Framework") as part of its life-cycle management of oil and natural gas wells, facilities and pipelines, which imposes mandatory annual minimum spend requirements on licensees for the closure of inactive wells and related infrastructure. Under the Framework, the AER assigns a licensee an annual minimum spend requirement for reclamation and abandonment activities to be completed based on a licensee's proportionate share of the provincial inventory of inactive wells and related infrastructure, among other factors. In Alberta, the mandatory minimum spend requirements are reviewed annually and have increased from 4% in 2022 to the current rate of 6.2% in 2025. The Government of Saskatchewan has a similar program in place (the Inactive Liability Reduction Program), which had a 6% minimum spend requirement in 2025. In British Columbia, the Dormancy and Shutdown Regulations also set out mandatory targets for the decommissioning and restoration of inactive wells and facilities. In addition to minimum spend requirements for abandonment and reclamation, each of the provincial regulators has the ability to require licensees to post financial security to secure a licensee's abandonment and reclamation obligations.

Carbon / GHG

Governments in jurisdictions where the Company operates have developed GHG regulations as part of their provincial, federal and international climate change commitments. The Company continuously monitors developments in the GHG regulatory environment in applicable jurisdictions to assess the cost impact of new and existing regulations on current and future operations and proposed projects under consideration.

- **Federal Carbon Policy and GHG Emissions Regulation**

  The federal government ratified the Paris Agreement, which included a commitment to reduce Canada's GHG emissions by 40-45% from 2005 levels by 2030. In December 2024, the federal government updated its commitment to extend the timing to achieve the national GHG emission reduction target to 2035. The federal regulations supporting the Paris Agreement mandate that the federal carbon price increase in annual increments of $15/tonne after 2022 to $170/tonne by 2030. The federal Clean Fuel Regulations ("CFR"), which took effect on July 1, 2023, require reductions in the carbon intensity of gasoline and diesel fuels produced or sold in Canada. The federal Clean Electricity Regulations ("CER") came into effect on January 1, 2025, and establishes GHG emission limits for almost all fossil fuel-powered electricity generation units, beginning in 2035.

  In addition to existing federal GHG regulations and the CFR, the federal government published draft regulations in 2024 that propose to cap emissions from the oil and gas sector through a national cap-and-trade system. This has not yet been implemented and is dependent on final agreements negotiated as part of the MOU (see below for further discussion). In 2025, new federal regulations were also released that are intended to control the release of volatile organic compounds (VOCs) from petroleum refineries and upgraders; truck, rail, marine, and pipeline terminals; petrochemical facilities; bulk fuel facilities; and steel mills.

  In November 2025, the federal and Alberta governments entered into the MOU which is intended to increase western Canada's energy production and establish Canada as an energy leader while reducing GHG emissions through innovative technologies and infrastructure programs. The MOU included the following:

  - The federal government agreed not to implement an oil and gas emissions cap, contingent on the province of Alberta meeting certain commitments, one of which is related to the development of carbon capture infrastructure;
  - The application of the CER in Alberta was suspended pending the finalization of a new carbon pricing agreement to be administered through Alberta's Technology Innovation and Emissions Reduction Regulation ("TIER") program, the details of which are to be negotiated and agreed upon by the parties on or before April 1, 2026; and
  - A commitment by the two governments to work collaboratively to design and implement a globally competitive, long-term carbon pricing scheme, carbon levy recycling protocols, and sector-specific stringency factors for large emitters in both the oil and gas and electricity sectors through Alberta's TIER system. Under this proposal, the TIER system will ramp up to a minimum effective credit price of $130/tonne. The two governments are anticipated to conclude an agreement on industrial carbon pricing on or before April 1, 2026 in furtherance of this agreement.

  Although the MOU appears supportive of Canada's energy sector, there are no assurances that the parties will reach final agreement on all of the necessary elements required to enable the MOU framework or the environmental laws and regulations negotiated as part of the MOU to have a favourable impact on the oil and natural gas industry in Alberta or the Company, or, if not adopted with the necessary elements, may ultimately have an adverse effect on the Company's business, financial condition and operations.

- **Provincial GHG Policy and Regulation**

  Industrial carbon pricing regulatory systems in all provinces are subject to periodic review by the federal government to assess the adequacy of the provincial systems against the federal Greenhouse Gas Pollution Pricing Act. To the extent a province's carbon pricing system does not meet the federal stringency requirements, the federal backstop regulations apply.

  Alberta: In Alberta, TIER sets the carbon pricing framework that applies to the Company's facilities with emissions greater than 100,000 tonnes CO_2e/year, and certain facilities opted into the TIER system by the Company. In 2025, the carbon price in Alberta for emissions above the TIER regulated limits was $95/tonne. In May 2025, the Alberta government indefinitely capped the carbon price at $95/tonne, which may be subject to change following finalization of a new carbon pricing agreement with the federal government on or before April 1, 2026 (as stipulated in the MOU). Emissions from the non-operated Scotford Upgrader and North West Redwater bitumen upgrader and refinery are also subject to TIER.

  British Columbia: In 2025, the industrial carbon price in British Columbia under the province's output-based price system was $95/tonne and will increase by $15/tonne CO_2e annually until it reaches $170/tonne of CO_2e in 2030, in alignment with the federal carbon pricing schedule. In 2023, British Columbia announced its intention to implement a Net-Zero New Industry policy as well as an emissions cap for the oil and gas industry. This cap is intended to ensure that the province meets its emissions reduction target of 33-38% below 2007 emission levels by 2030. In 2024, British Columbia announced that it would be introducing regulatory measures to backstop the federal carbon emissions cap, which were to apply in the event of gaps between federal and provincial targets, and in the event that the federal emissions cap is not implemented or cancelled.

  Saskatchewan: As part of its Prairie Resilience Plan, in 2018 the Saskatchewan government enacted the Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations, that apply to facilities emitting more than 25 kilotonnes of CO_2e annually. This regulation required the Company's North Tangleflags in situ heavy crude oil facility and the Senlac in situ heavy crude oil facility to meet reduction targets for GHG emissions commencing in 2020. This regulation also enables facilities that emit less than 25 kilotonnes of CO_2e annually to aggregate and opt-in to the Saskatchewan regulatory system as an alternative to the federal fuel charge. In April 2025, the province of Saskatchewan paused the application and collection of industrial carbon taxes. Since this would result in Saskatchewan not meeting the federal stringency requirement, the province may be subject to the federal backstop regulation if applied by the federal government in the future.

  Manitoba: In the absence of provincial regulations for carbon pricing and GHG emissions, the federal output-based pricing system and carbon pricing schedule applies to Manitoba facilities with emissions greater than or equal to 50 kilotonnes CO_2e annually. Facilities with emissions equal to or greater than 10 kilotonnes CO_2e annually can voluntarily opt-in to the system.

- **Methane Emissions Reduction Regulations**

  The federal government's methane regulation which came into effect on January 1, 2020, applies nationally unless provinces reach equivalency agreements with the federal government. The federal government originally had a commitment to reduce methane emissions from the oil and gas sector by 40-45% from the 2012 levels by 2025. In 2021, the federal government set a target to further reduce methane emissions to achieve at least a 75% reduction below 2012 levels by 2030.

  The provinces of British Columbia, Alberta and Saskatchewan have equivalency agreements in place with the federal government that allow the applicable provincial methane regulations to govern in these three western provinces. The federal methane regulation continues to apply in the province of Manitoba.

  Pursuant to the MOU, the federal and Alberta governments intend to enter into a new methane equivalency agreement on or before April 1, 2026. Once concluded, this new equivalency agreement will extend the target date to achieve the mandated 75% methane emissions reduction (relative to 2014 levels) to 2035. In December 2025, the final methane regulation was enacted by the federal government, with phase-in of the regulatory requirements beginning January 1, 2028.

United Kingdom

Under existing law, the UK government has broad authority to regulate the petroleum industry, including exploration, development, conservation and rates of production.

Taxation

Effective January 1, 2016, the Petroleum Revenue Tax ("PRT") rate, which is a charge on certain crude oil and natural gas profits, was reduced to 0%. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes remain recoverable at 50%. In addition, the supplementary charge on oil and gas profits was reduced to 10%, also effective in 2016. An Investment Allowance on qualifying capital expenditures is deductible for supplementary charge purposes, subject to certain restrictions. For Corporation Tax and Supplementary Charge, allowable losses are eligible for carryback to prior taxation years. The UK government introduced an Energy Profits Levy ("EPL") in May 2022 at a rate of 25%. This was subsequently increased to 35% in November 2022. From November 1, 2024, the EPL was further increased to 38% and the investment allowance on qualifying capital expenditure of 29% was abolished. As a result of these changes, the tax rate applicable to taxable income from oil and gas activities is 78% subject to deduction of available investment allowance.

In 2013, the UK government introduced a Decommissioning Relief Deed ("DRD"), which is a regulatory and contractual mechanism whereby the UK government guarantees its participation in future field abandonments through a recovery of PRT and corporate income tax.

Carbon / GHG

GHG emissions from the Company's UK operations are regulated under the UK Emissions Trading Scheme ("ETS"), which was launched on January 1, 2021 and replaced the UK's participation in a comparable European Union ("EU") system. The UK scheme is aligned with the EU ETS rules and applies to energy intensive industries, the power generation sector and aviation.

Offshore Africa

The terms of licences, including royalties and taxes payable on production or profit sharing arrangements, as appropriate, vary by country and, in some cases, by concession within each country.

Development of the Espoir Field in Block CI-26 and the Baobab Field in Block CI-40, Offshore Côte d'Ivoire ("CDI"), are subject to Production Sharing Contracts ("PSC") which deem that tax or royalty payments to the government are satisfied by the government's share of profit oil. The current corporate income tax rate in CDI is 25% which is applicable to non-PSC income.

In 2019, the CDI government communicated its intent to require the oil and gas sector operating in its jurisdiction to comply with the West African Economic and Monetary Union currency control regulations. The Company continues its discussions with the applicable authorities on a mechanism that will satisfy these regulations while, at the same time, allow for the expatriation of foreign currency not required for use by the Company in country.

On January 24, 2025, the amendments to CDI's local content regulations took effect, which increased the requirement to use local personnel, businesses and services in Company operations. The Company has worked with its contractors and applicable authorities with regard to compliance with these regulations.

C. COMPETITIVE FACTORS

The energy industry is highly competitive in all aspects of the business including the exploration for and the development of new sources of supply, the construction and operation of crude oil and natural gas pipelines and related facilities, the acquisition of crude oil and natural gas interests, the transportation and marketing of crude oil, natural gas, NGLs and surplus electricity generated at Company facilities, and the attraction and retention of skilled personnel. The Company's competitors include both integrated and non-integrated crude oil and natural gas companies as well as other petroleum products and energy sources.

D. RISK FACTORS

Given the dynamic nature of risk, the Company uses a multidisciplinary Enterprise Risk Management ("ERM") framework to identify, assess, and develop mitigation plans for risks that may affect the Company and its operations. The ERM framework incorporates a matrix approach to risk assessment that categorizes and aligns risks across operational areas, allowing teams to better understand the identified risks, their impacts on the Company's operations and the mitigation being undertaken to address these risks. This allows management to monitor potential risk exposures and the steps taken to address the identified risks or otherwise mitigate these exposures by identifying those individuals on the Company's Management Committee responsible for each of the identified risks. Reporting on the risks and related mitigating activity throughout the Company is also part of the ERM framework.

Volatility of Crude Oil and Natural Gas Prices

The Company's financial condition is substantially dependent on, and highly sensitive to, the prevailing price for crude oil and natural gas. Significant declines in crude oil or natural gas prices could have a material adverse effect on the Company's operations and financial condition and the value and amount of its reserves. This could include: a delay or cancellation of existing or future drilling, development, construction or expansion programs; curtailment in production at some properties; or result in unutilized long-term transportation commitments, all of which could have a material adverse effect on the Company's financial condition.

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 additional factors beyond the Company's control including instability in the international trade environment as a result of actual or threatened trade action by Canada and the US, or other key trade partners, including the imposition or threatened imposition of tariffs and retaliatory trade measures. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of OPEC+, the economic condition of Canada, the US, the European Union and Asia, government regulation, political stability in the Middle East and elsewhere, geopolitical conflicts (e.g. conflicts in the Middle East, in Ukraine and in Venezuela), the foreign supply of crude oil, the restriction or disruption of global trade routes, the price of foreign imports, the ability to secure adequate transportation for products which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity, government mandated curtailment, the availability of alternate fuel sources, weather conditions, and other factors. Natural gas prices realized by the Company are affected primarily in North America by supply and demand, weather conditions, industrial demand and the ability to secure adequate transportation for products, which could also be affected by pipeline constraints, government mandated curtailment, prices of alternate sources of energy, and government regulation. Crude oil and natural gas producers in Canada may receive discounted prices for their production relative to international prices due in part to constraints on the ability to transport and sell products to international markets. An ongoing failure to resolve such

constraints may extend the duration of discounted or reduced commodity prices realized by crude oil and natural gas producers, including the Company.

Any substantial or extended decline in prices of crude oil or natural gas could result in a delay or cancellation of existing or future drilling, development, construction or expansion programs, including, without limitation, at Horizon, AOSP, Primrose, Pelican Lake, Kirby, Jackfish, Pike, and international projects, or curtailment in production at some properties, or result in unutilized long term transportation commitments, all of which could have a material adverse effect on the Company's financial condition.

Approximately 27% of the Company's 2025 production on a BOE basis was primary heavy crude oil, Pelican Lake heavy crude oil and bitumen. The market prices for these products differs from the established market indices for light and medium grades of crude oil due principally to quality differences. As a result, the price received for these products currently differs from the benchmark they are priced against. Future quality differentials are uncertain and a significant increase in the differential could have a material adverse effect on the Company's financial condition.

The Company conducts periodic assessments of the carrying value of its assets in accordance with IFRS Accounting Standards. If crude oil and natural gas forecast prices decline, the carrying value of related property, plant and equipment could be subject to downward revisions, and net earnings could be adversely affected.

Political and International Risk

The Company markets its production in Canada, the United States and internationally. Considering the physical and economic integration of the North American energy markets, any actual or proposed material changes to the international trade environment between Canada and US or other key trade partners, including with respect to governing treaties or trade agreements, or the actual or threatened imposition of trade barriers (including tariffs, quotas, embargoes, safeguards, or other measures), may introduce uncertainty in the markets, have a material effect on commodity prices generally and the crude oil and natural gas prices realized by the Company; increase the cost or reduce the supply of products available to the Company; or require changes to the Company's supply chain or other business practices, any of which have the potential to negatively impact the Company's business, financial condition, and results of operations if the scope or duration of such actions are prolonged.

The tariff environment between the US and Canada continues to evolve. Although the parties have engaged in bilateral trade talks, the US government currently imposes 10% tariffs on all Canadian products not meeting the Canada-United States-Mexico Agreement rules of origin. In addition, recent international developments related to Arctic security indicate the possibility that additional US tariffs may be imposed on various Canadian products if such concerns are not resolved. The recent political volatility in Canada's economic relationship with the United States has caused significant uncertainty over the scope, timing and duration of any actual or proposed tariffs and retaliatory measures, as well as the potential availability of exceptions and exemptions and/or changes to free trade agreements. The effect of trade actions or threatened trade actions may have an impact on the market and pricing received for the Company's products, increase the cost or reduce the availability of products in the Company's supply chain and introduce additional foreign currency volatility. At this time, the duration and impact of instability in the Canada - US trade environment and associated trade actions remains uncertain. The Company will continue to monitor the trade environment and assess the impacts of actual or potential tariffs on its business, financial condition and results.

Environmental Risks

All phases of the crude oil and natural gas business are subject to environmental regulation pursuant to a variety of Canadian, US, UK, European Union, African and other national, federal, provincial, state and municipal laws and regulations as well as international conventions (collectively, "environmental legislation").

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation also requires that wells, mines, facility sites and other properties associated with the Company's operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations including exploration and development projects and material changes to existing projects may require additional regulatory approvals, including environmental impact assessments or permit applications. Compliance with environmental legislation can require significant expenditures and failure to comply may result in the imposition of fines and penalties or the suspension of operations pending the completion of appropriate remedial measures. The costs of complying with environmental legislation in the future may have a material adverse effect on the Company's business, financial condition and results of operations.

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulatory compliance, particularly in North America and the North Sea. In respect of its offshore operations, the Company also participates with regulators and industry partners in addressing environmental monitoring and emergency response protocols that are applicable to the Company's operations in these jurisdictions. Environmental monitoring in the oil sands is performed in collaboration with the federal and provincial governments, Indigenous communities and industry, in order to enhance the understanding of the cumulative effects of oil sands development. Existing and anticipated future legislation and regulations may require the Company to address and mitigate the effect of its activities on the environment. Increasingly stringent laws and

regulations may have a material adverse effect on the Company's business, financial condition and results of operations. A summary of key environmental risks is set out below:

- **Carbon / GHG Emissions Management**

  As part of its evaluation of climate change risk, the Company reviews independent external scenario analyses developed by energy firms and agencies representing a range of global oil and natural gas demand levels through 2050. These external scenario analyses are a tool used by the Company to support business planning, identification of risks and opportunities, and include the consideration of a number of variables and assumptions related to markets, (e.g, economic and social events), commodity prices, carbon prices, policy, regulation, technology development and adoption, energy efficiency and reputation. Under certain stringent low-carbon scenarios, potential demand/supply changes for oil and natural gas products may impact commodity prices; however, it is not currently possible to predict either the timing or precise effects of a potential transition to a lower-carbon economy. Since the Company plans and evaluates opportunities partially on the basis of climate-related assumptions, variations between actual outcomes and expectations may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows. Aspects of climate change risk that have the most potential to influence the Company's business strategy include: future regulatory changes, including government imposed emissions caps, associated compliance costs and reduction targets, access to markets and capital, changes to societal preferences and other factors that may accelerate the transition to alternate fuel sources, reputational risk, and technology development, as described in more detail below.

- **Future Regulatory Changes / Compliance Costs / Reduction Targets**

  The additional requirements of existing or proposed GHG regulations on the Company's operations may increase capital expenditures and production expenses, including those related to the Company's oil sands projects, planned expansions or new developments. This may have an adverse effect on the Company's financial condition. Accordingly, existing and proposed changes to GHG policies and regulations are considered when making decisions to advance the Company's business strategy. The Company tracks the development of GHG policies and regulations at the international, national, federal and provincial level.

  Various jurisdictions have enacted or are evaluating standards related to the upstream GHG emissions of products (e.g., low carbon fuel standards and methane emission requirements for liquified natural gas), which may affect access to market for hydrocarbons with higher emissions intensity. The regulation of air pollutants to meet ambient air quality objectives (typically as part of regional air zone management) may result in the Company spending additional capital to retrofit equipment in specific regions, depending on future ambient air quality trends.

  The Company's ability to achieve government and corporate emissions or environmental reduction targets could require the development of new technology, the success of which is unknown, as well as significant capital and resources, with the potential that the costs required to achieve targets and goals are materially different from original estimates and expectations. While the intent is to improve efficiency and increase the offering of low carbon energy, the shift in resources and focus to emissions reductions could negatively impact operating results.

- **Societal Preferences / Reputational Risk**

  Changes in public support for climate action, particularly for oil sands, combined with increased activism and opposition to fossil fuels, which are designed to change consumption habits in order to accelerate the reduction of the global consumption of carbon-based energy, may impact the market for the Company's products and securities and impact its ability to obtain approvals for new projects. The timing and pace of change to a low carbon economy is uncertain and the ability to access insurance and capital may be adversely affected in the event that financial institutions, investors, insurers, rating agencies and/or lenders adopt more restrictive de-carbonization policies. In addition, behavioural changes by the public (such as a shift in transportation preferences or government policy changes which promote the use of electric vehicles or alternative energy sources), may impact the demand for crude oil and the Company's products. Similarly, the Clean Electricity Regulations may impact the demand for natural gas.

- **Access to Markets**

  The Company's production is transported through various third-party transport systems for sale to markets. The impact of tariffs and/or export taxes on the Company's products, or restricted availability of transport systems could limit the ability to deliver production volumes and adversely affect commodity prices, sales volumes and/or the prices received for the Company's products, projected production growth, operations and cash flows. The Company may also be exposed to greater market risk with the shift to a lower carbon emissions future. These risks may include shifting demand for various energy sources, including increasing demand for renewable energy, and increases in the Company's compliance costs that may not be recoverable in the price of its products, which could delay the development of certain assets. An additional risk includes the potential for restricted access to markets for higher carbon energy sources, which could result in the delay, revocation, or conditions imposed on, regulatory approvals for pipeline projects. These market risks could result in a competitive disadvantage if producers in other jurisdictions are not subject to similar regulatory burdens. There is no certainty that alternative routes or modes of transportation for the Company's production will be available or sufficient to address any gaps caused by operational constraints on applicable pipeline systems.

- **Technology Development**

  Regulatory and policy changes to address climate change may require the Company to develop or adopt new sustainable technologies to reduce its environmental footprint and to support the transition to a lower carbon emissions/energy efficient economy at significant cost. In addition, the development, emergence and use of renewable energy sources could affect the demand for the Company's products thereby affecting its competitiveness and profitability. The development and commercialization (including the availability, cost and effectiveness) of new technologies necessary to achieve emissions reductions and environmental improvements is uncertain.

- **Regulatory and Policy Effectiveness**

  The Company operates under government regulation and policy for the crude oil and natural gas sector including, land tenure, royalties, taxes, production rates, environmental management, and safety performance. Before proceeding with major projects, the Company must follow various regulatory processes to obtain project approvals and permits. These processes may include Indigenous and other stakeholder consultation, environmental impact assessments and public hearings. The Company's project execution and timelines could be impacted by delays experienced through the regulatory process or by conditions placed on its operations through permit approvals. Regulatory changes may also impact the costs associated with advancing a project or provide opportunities to streamline the regulatory process and/or accelerate timelines to obtain regulatory approval. The Building Canada Act (Canada) ("BCA") which came into force on June 26, 2025, enables the government to streamline federal approval processes to get major projects built faster. The projects anticipated to benefit from a streamlined approval process include ports, railways, energy corridors, critical mineral developments, and clean energy initiatives.

  Further, to facilitate energy collaboration and build a more competitive and sustainable economy, the federal and Alberta governments entered into the MOU. Although the MOU appears supportive of Canada's energy sector, there are no assurances that the parties will reach final agreement on all of the necessary elements required to enable the MOU framework or the environmental laws and regulations negotiated as part of the MOU to have a favourable impact on the oil and natural gas industry in Alberta or the Company, or, if not adopted with the necessary elements, may ultimately have an adverse effect on the Company's business, financial condition and operations.

  Changes in government policy have the potential to impact the certainty and timelines for the regulatory approval process on large energy projects, including increased requirements for Indigenous consultation. Some examples include the federal Net-Zero Emissions Accountability Act (Canada), which implements the United Nations' Declaration on the Rights of Indigenous Peoples Act, and the federal Impact Assessment Act (Canada), the Alberta sub-regional plans supporting caribou recovery, the British Columbia Declaration on the Rights of Indigenous Peoples Act, and the Blueberry River First Nations Implementation Agreement, which was negotiated by the Government of British Columbia to address issues raised in Indigenous litigation (i.e., *Yahey* vs. *British Columbia* 2021 (B.C.S.C. 1287), a case regarding the cumulative effects of development on Treaty 8 rights).

- **Tailings Management**

  The Alberta Energy Regulator ("AER"), updated Directive 85 - Fluid Tailings Management for Oil Sands Mining Projects ("Directive 85"), in October 2017. Directive 85 establishes performance criteria for tailings operations and sets out the requirements for approval, monitoring and reporting in respect of tailings ponds and tailings management plans.

  The Company continues to implement and adhere to the conditions stipulated in the approved Tailings Management Plans for the Horizon Mine, and Albian's Muskeg River and Jackpine Mines and thereby meet the requirements of the Government of Alberta's Tailings Management Framework (2015) and Directive 85. In addition, the Company obtained approval for the Updated Tailings Management Plans (2023) for Muskeg River and Jackpine Mines. The tailings management plans outline progressive changes to improve performance in tailings management for the full life of the mines as well as the proposed tailings treatment technologies. All three of the Company's mines (Horizon, Muskeg River and Jackpine) continue to meet the expectations outlined within its approved plans. However, in the future, there is the potential risk of exceeding the approved site-specific tailings profiles resulting in the requirement to post additional security under the Mining Financial Security Plan as well as the potential application of a compliance levy. The Company has systems and processes in place for monitoring tailings performance, which uses adaptive management and continuous improvement principle, including research and mitigation technology development to reduce fluid tailings. Through Canada's Oil Sands Innovation Alliance, the innovation arm of Oil Sands Alliance (formerly, Pathways Alliance), technology development is jointly undertaken by all oil sands mine operators to accelerate the commercialization of such technologies.

  The Company's Oil Sands Mining operations continue to plan and execute progressive reclamation activities on the side slopes of its tailings facilities. Muskeg River Mine has advanced the decommissioning and reclamation process for its external tailings facility (South Expansion Area) and is waiting for the final construction completion report to be authorized before finalizing the regulatory requirements with the AER for its deregistration as a dam structure. The South Expansion Area was fully revegetated and reclaimed in 2023 with ongoing reclamation monitoring. Muskeg River Mine's main external tailings facility became inactive at the end of 2025 when the tailings lines were removed. In 2026, the facility will commence the decommissioning process.

- **Land Use, Water and Wildlife Management**

  Legislation and policies related to land management may affect development and operations risk through changes in regional limits on operating standards for air emissions, water use, land disturbance, reclamation and biodiversity. Land use planning may set aside areas for conservation, parks, or establish operational constraints to protect wetlands, watercourse shorelines, biodiversity and wildlife that may place limits on crude oil and natural gas development. Management frameworks in the Lower Athabasca oil sands area define thresholds for air emissions, surface and ground water quality and quantity that could increase the standards for the operation of facilities. Draft frameworks on biodiversity may establish further limits on development that may limit operations and expansion of facilities. Sub-regional management plans may pose limitations on resource development through limits on infrastructure. In June 2024, the federal government released the draft Nature Accountability Bill to legislate the protection of biodiversity as a method to achieve conservation of 30% of Canada's land area, including the requirement for large companies and financial institutions to monitor, assess and disclose their risks, dependencies and impacts on biodiversity.

  Water licencing, use and release standards are becoming increasingly stringent both in the process of obtaining access to water and to manage it efficiently. Alberta Wetland Policy changes may increase requirements and payments for new project development. Federal and provincial standards governing the treatment and release of water from oil sands projects into the environment are currently under development having regard to applicable regulations governing other mining operations in Canada.

  The Species at Risk Act (Canada) requires the maintenance of habitat for a variety of species. For example, in the case of Woodland Caribou, the regulatory requirements related to undisturbed habitat in addition to minimum herd population may impact plans for crude oil and natural gas expansion. Both the oil and gas and forestry industries are undertaking mitigation measures to maintain habitat function by restricting predator access on seismic lines, reestablishing forests through accelerated reclamation and completing project development planning to minimize caribou disturbance.

Operational Risk

Exploring for, producing, mining, extracting, upgrading and transporting crude oil, natural gas and NGLs involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These activities are subject to a number of hazards and risks which may result in, or contribute to, operational impacts or disruptions, including fires, explosions, spills, blow outs, drought or other water shortages or restrictions, or other unexpected or dangerous conditions causing personal injury, property damage, environmental damage, induced seismicity associated with industrial activities, interruption of operations and loss of production, whether caused by human error, natural or other causes. In addition to the foregoing, the oil sands mining and upgrading operations are also subject to loss of production, potential shutdowns and increased production expenses due to the complexity and integration of the various component parts necessary to mine, extract, process and upgrade bitumen.

The Company's business also carries risks associated with environmental and safety performance, which are closely scrutinized by governments, the public and the media, and could result in the suspension of or the inability to obtain regulatory approvals and permits, or, in the case of a major incident, fines, civil suits, and/or criminal charges against the Company.

Extreme weather events and climate conditions, including, but not limited to, floods, droughts, wildfires, and greater variability in seasonal temperatures may pose physical risks to the Company's operations with potential impacts to supply chain and customer/vendor operations or critical infrastructure owned and operated by the Company or third parties. A comprehensive corporate Emergency Management program is in place to coordinate the Company's response to potential accidents and incidents (including extreme weather events). This program includes Emergency Response Plans intended to ensure a prompt initial response and efficient management of situations as they arise.

The jurisdictions where the Company operates are subject to labour legislation and regulations that, if changed, may impact operations. In addition, labour risk associated with work interruptions and the ability to secure necessary workers may impact the timely and cost effective manner in which projects are completed.

Reserves Replacement

The Company's future crude oil and natural gas production, and therefore its cash flows and results of operations, are highly dependent upon success in exploiting its current reserves base and acquiring or discovering additional reserves. Without additions to reserves through exploration, acquisition or development activities, the Company's production will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent the Company's cash flow is insufficient to fund capital expenditures and external sources of capital become limited or unavailable, the Company's ability to make the necessary capital investments to maintain and expand its crude oil and natural gas reserves will be impaired. In addition, the Company may be unable to find and develop or acquire additional reserves to replace its crude oil and natural gas production at acceptable costs.

Uncertainty of Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors, both internal and external, beyond the Company's control. Revisions are often necessary as a result of newly acquired technical data, technology improvements, or changes in historical performance, production costs, development costs, product pricing, economic conditions, market availability, or regulatory requirements. In general, estimates of economically recoverable crude oil, natural

gas and NGLs reserves and the future net revenue therefrom are based upon a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of royalty regimes, higher costs as a result of environmental and other regulation by governmental agencies, estimates of future commodity prices, production costs and the timing and amount of future development expenditures, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable crude oil, natural gas and NGLs reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The Company's actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to its reserves will likely vary from such estimates, and such variances could be material. Estimates of reserves that may be developed in the future are often based upon volumetric calculations, decline curve analysis and upon analogy to actual production history from similar reservoirs and wells. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves.

Project Risk

The Company has a variety of exploration, development and construction projects, including environmental mitigation and GHG reduction projects, underway at any given time. Project delays may result in delayed revenue receipts and/or cost overruns may result in projects being uneconomic. The Company's ability to complete projects is dependent on general business and market conditions as well as other factors beyond the Company's control including the availability of skilled labour and workers, the availability and proximity of materials, pipeline capacity, trade measures and tariffs, weather, fires, drought, inflationary cost pressures, legal and regulatory matters (including environmental legislation and government imposed emissions caps), ability to access lands, availability of drilling and other equipment, availability of GHG reduction technologies, and availability of processing capacity.

Sources of Liquidity

The ability to fund current and future capital projects and carry out the business plan is dependent on the Company's ability to generate cash flow as well as raise capital in a timely manner under favourable terms and conditions and is impacted by the Company's credit ratings and the condition of the capital and credit markets. Public and stakeholder scrutiny of the Company's stated environmental, sustainability and climate-related targets is increasing. Any failure, or perceived failure, in achieving the Company's stated targets, or the perception that such targets are insufficient or are not achievable within the anticipated timeline, if any, could affect the Company's ability to access cost-effective capital. In addition, changes in credit ratings may affect the ability to, and the associated costs of, entering into ordinary course derivative or hedging transactions, as well as entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms. The Company also enters into various transactions with counterparties, including joint venture partners, and is subject to credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including a failure of counterparties and successors in interest to meet their share of abandonment and reclamation obligations. Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital consisting of cash flows from operating activities, available credit facilities, commercial paper, and access to debt capital markets, to meet obligations as they become due.

Information Systems

The Company increasingly relies on information systems ("IS") to effectively operate its business. This includes computer hardware, networks, software, cloud services, mobile applications and systems using artificial intelligence ("AI"). In the ordinary course of business, the Company collects, uses and stores sensitive data, including intellectual property, proprietary information, business information and personal information of the Company's employees, vendors and customers. Despite the Company's security measures in place, IS may still be vulnerable to cyber-incidents (including those performed by malicious nation states, cyber criminals, hacktivists or compromised third parties), disruptions from employee or third-party error, malfeasance, natural disasters, activism, terrorism, war, regional or international conflict.

Any such incident could result in the loss or disclosure of confidential or private data, asset damage, financial losses, operational disruption, legal claims, regulatory penalties, physical harm to people or the environment, and reputational issues with suppliers, customers, stakeholders and business partners.

- **Cybersecurity**

  Cybersecurity risks continue to evolve as threat actors use increasingly advanced tools, including AI. To manage these risks, the Company maintains a comprehensive industry standard cybersecurity framework that includes: IS policies and guidelines, 24-hour managed security monitoring and response, regular cyber assessment of critical third parties, ongoing penetration testing of external systems, annual targeted penetration testing of IS services, incident response readiness drills, routine mandatory cyber education/test programs, multi-factor authentication, data restoration and recovery processes, vulnerability scanning, risk based remediation of vulnerabilities, expedited security patching, in addition to internal accounting and process controls. Cybersecurity oversight is provided by the Audit Committee, which receives updates from management at least semi-annually or more often when required. The Company maintains insurance as part of its risk management program, but such insurance may not cover all damages in connection with a cyber incident, and in some

instances, certain damages may be excluded from coverage due to the nature of the damages sustained or the causation of the incident.

- **Artificial Intelligence**

  The Company uses AI responsibly to expand employee access to knowledge, deliver data-driven insights and improve efficiency through incremental, cost-justified deployments. The Company will not rely on AI for time-sensitive or production critical processes until controls and evaluations meet necessary standards. Employees must remain actively involved in all AI creation, review, and decision-making while remaining accountable for AI outcomes. Policies, guidelines and technical safeguards are in place to manage AI risks, though these measures cannot eliminate all potential issues. AI related risks and activities are managed with the Company's enterprise risk management system, which is reported on to the Nominating, Governance and Risk Committee at least annually, as well as included in the semi-annual cybersecurity report provided to the Audit Committee. As AI regulations continue to emerge and evolve, compliance may increase costs or limit how AI can be used in Company operations.

Foreign Investments

The Company's foreign investments include risks typically associated with investments in developing countries such as uncertain political, economic, legal and tax environments. These risks may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, war, insurrection, civil unrest and other political risks, risk of increases in taxes and governmental royalties, renegotiation of contracts with governmental entities and quasi-governmental agencies, changes in laws and policies governing operations of foreign based companies, including compliance with existing and emerging anti-corruption laws, and other uncertainties arising out of foreign government sovereignty over the Company's international operations. In addition, if a dispute arises in its foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of a court in Canada or the United States.

The Company's arrangement for the exploration and development of crude oil and natural gas properties in Canada and the UK sector of the North Sea differs distinctly from its arrangement for the exploration and development of crude oil and natural gas properties in other foreign jurisdictions. In some foreign countries in which the Company does and may do business in the future, the state generally retains ownership of the minerals and consequently retains control of, and in many cases participates in, the exploration and production of reserves. Accordingly, operations may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses, local content requirements, currency requirements and other charges. In addition, changes in prices and costs of operations, timing of production, and other factors, may affect estimates of crude oil and natural gas reserves quantities and future net revenues attributable to foreign properties in a manner materially different than such changes would affect estimates for Canadian properties. Agreements covering foreign crude oil and natural gas operations also frequently contain provisions obligating the Company to spend specified amounts on exploration and development, or to perform certain operations or forfeit all or a portion of the acreage subject to the contract.

Risk Management Activities

In response to fluctuations in commodity prices, foreign exchange, and interest rates, the Company may periodically utilize various derivative financial instruments and physical sales contracts to manage its exposure under a defined hedging program. The terms of these arrangements may limit the benefit to the Company of favourable changes in these factors and may also result in royalties being paid on a reference price which is higher than the hedged price. There is also increased exposure to counterparty credit risk.

Dividends and Share Repurchases

The payment of future dividends and the repurchase of Company common shares is dependent on, among other things, its financial condition and other business factors considered relevant by the Board of Directors including prevailing economic conditions, the Company's anticipated requirements to fund operations and projects, debt servicing obligations and compliance with applicable regulatory and stock exchange requirements. The dividend policy and the free cash flow[(1)] allocation policy (which allocates returns to Company shareholders through share repurchases after capital requirements and the payment of dividends), each undergo periodic review by the Board of Directors and are subject to change.

Other Business Risks

Other business risks which may negatively impact the Company's financial condition include regulatory issues, risk of increases in government taxes and changes to royalty regimes, risk of litigation, risk to the Company's reputation resulting from operational activities that may cause personal injury, property damage or environmental damage, labour risk associated with securing the workers necessary to complete capital projects in a timely and cost effective manner, severe weather conditions, the timing and success of integrating the business and operations of acquired companies and businesses, and the dependency on third party operators for certain of the Company's assets.

(1) The term "free cash flow" is a Non-GAAP Measure. Refer to the "Advisory" section of this AIF for further details regarding Non-GAAP Financial Measures.

In addition, epidemics or pandemics have the potential to disrupt the Company's operations, projects, and financial condition through the disruption of the local or global supply chain and transportation services, or the loss of workers resulting from quarantines that affect the Company's labour pools in local communities, workforce camps or operating sites or that are instituted by local health authorities as a precautionary measure, any of which may require the Company to temporarily reduce or shutdown its operations depending on the extent and severity of a potential outbreak and the areas or operations impacted. However, during an epidemic or pandemic, the Company's operations may be designated as "essential services" by applicable government authorities (as was the case for the COVID-19 pandemic), which permitted operations to continue in areas that may have otherwise been impacted by government imposed lockdown measures. Depending on the severity of an outbreak, the timing and availability of vaccines and the speed of vaccine distribution, a large scale epidemic or pandemic could impact the international demand for commodities and have a corresponding impact on the prices realized by the Company for its products, which could have a material adverse effect on the Company's financial condition.

Some of the Company's assets are held in one or more corporate subsidiari es or partnerships. In the event of the liquidation of any corporate subsidiary, the assets of the subsidiary would be used first to repay the indebtedness of the subsidiary, including trade payables or obligations under any guarantees, prior to being used to repay the indebtedness of the Company.

Competition Act

On June 20, 2024, amendments to the Competition Act (Canada) came into force with the adoption of Bill C-59, An Act to Implement Certain Provisions of the Fall Economic Statement, which impacted environmental and climate disclosures by businesses. As a result of these amendments, certain public representations by a business regarding the benefits of the work it is doing to protect or restore the environment or mitigate the environmental and ecological causes or effects of climate change may violate the Competition Act's deceptive marketing practices provisions. These amendments include substantial financial penalties and, effective June 20, 2025, a private right of action which will permit private parties to seek an order from the Competition Tribunal under the deceptive marketing practices provisions. Subsequently, on November 4, 2025, the federal government tabled the 2025 Budget, which proposed further amendments to the Competition Act, namely removing the requirement that businesses substantiate their environmental representations about a business or business activity based on an internationally recognized methodology, and eliminating private rights of action under the revised business-activity greenwashing provision. Uncertainty surrounding the interpretation and enforcement of this legislation, which includes the status of any proposed or future amendments, may expose the Company to increased litigation and financial penalties, the outcome and impacts of which can be difficult to assess or quantify and may have a material adverse effect on the Company's business, reputation, financial condition, and results. To mitigate its exposure to claims, the Company has taken various steps, including employee training, adopting internal procedures for review of its public statements and the removal of certain public-facing communications containing environmental and climate communications. Although the Company continues to advance its environmental projects and to improve its performance, the Company has adopted a conservative approach to its public representations pending further guidance from the Competition Bureau, the Competition Tribunal and the courts.

Modern Slavery Act

On January 1, 2024, the Fighting Against Forced Labour and Child Labour in Supply Chains Act (the "Modern Slavery Act") came into force in Canada. The Modern Slavery Act obligates the Company to publish an annual modern slavery report detailing steps regarding the previous year's efforts to mitigate the risk of forced labour used at any step in its supply chain, including production of goods in Canada or elsewhere or of goods imported into Canada. There is a risk that the Company's supply chain may actually use or be alleged to have used forced labour or child labour, and there may be difficulty in gathering sufficient information from suppliers. The Company continues to assess this risk and determine what measures can be put in place to mitigate any identified exposures, which may affect the Company's operational efficiency, results of operations, financial condition, or reputation. For further information, please refer to the Company's 2024 Modern Slavery Annual Report, published at https://www.cnrl.com/about-us/code-of-conduct-and-human-rights/. This Report is not incorporated by reference into this AIF.

For additional details regarding the Company's risks and uncertainties, refer to the Company's annual MD&A for the year ended December 31, 2025, dated March 4, 2026.

Form 51-101F1 Statement of Reserves Data and Other Information

For the year ended December 31, 2025, the Company retained Independent Qualified Reserves Evaluators ("IQRE"), Sproule International Limited ("Sproule ERCE") and GLJ Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves with an effective date of December 31, 2025 and a preparation date of February 9, 2026. Sproule ERCE evaluated and reviewed the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, thermal bitumen, natural gas and NGLs reserves. GLJ evaluated the Oil Sands Mining and Upgrading mining bitumen and SCO reserves. The evaluations and reviews were conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's IQREs to review the qualifications of and procedures used by each IQRE in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves.

In 2025, the Company completed the AOSP asset swap with Shell Canada Limited and affiliates. As a result of the transaction, the Company acquired the remaining 10% working interest in the AOSP mines in exchange for a 10% working interest in the non-operated Scotford Upgrader and Quest. The Company now owns a 100% working interest in the AOSP mines and retains an 80% working interest in the non-operated Scotford Upgrader and Quest. Due to the difference of ownership interest between the AOSP mines and Scotford Upgrader and Quest and in accordance with NI 51-101 requirements, 80% of the reserves and sales volumes are disclosed as SCO and the remaining 20% are disclosed as mining bitumen.

In 2025, it was also determined that the North Sea reporting jurisdiction was no longer economic and the Company de-booked associated crude oil and natural gas reserves in such reporting jurisdiction as at December 31, 2025. Notwithstanding this decision, four crude oil fields remained in production at the end of 2025 and will continue to produce during portions of the decommissioning phase of these assets. As there are no reserves to disclose, the North Sea reporting jurisdiction has been removed from certain tables in the following disclosure.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual report on Form 40-F filed with the SEC in the "Supplementary Oil and Gas Information" section of the Company's 2025 Annual Report, which is incorporated herein by reference.

Information in the reserves data tables may not add due to rounding. BOE values and crude oil and natural gas metrics may not calculate due to rounding.

The estimates of future net revenue presented in the tables below do not represent the fair market value of the reserves.

There is no assurance that the price and cost assumptions contained in the forecast case will be attained and variances could be material. The estimates of recovery and reserves of crude oil, natural gas and NGLs provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGLs reserves may be greater or less than the estimate provided herein. Refer to "Special Note Regarding Forward-Looking Statements" and "Special Note Regarding Currency, Financial Information, Production and Reserves" in the "Advisory"; and the "Risk Factors" section of this AIF.

Oil and Gas Reserves Tables and Notes

Summary of Company Gross Reserves

As of December 31, 2025
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Thermal Bitumen (MMbbl)	Mining Bitumen (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America									
Proved									
Developed Producing	120	130	188	684	835	7,043	5,859	229	10,206
Developed Non-Producing	2	6	—	42	—	—	272	13	109
Undeveloped	141	92	55	2,603	14	91	11,868	575	5,548
Total Proved	264	228	243	3,330	849	7,134	17,999	817	15,864
Probable	107	105	107	1,845	46	554	9,965	404	4,828
Total Proved plus Probable	371	333	349	5,175	895	7,688	27,964	1,221	20,693
North Sea									
Proved									
Developed Producing	—						—		—
Developed Non-Producing	—						—		—
Undeveloped	—						—		—
Total Proved	—						—		—
Probable	—						—		—
Total Proved plus Probable	—						—		—
Offshore Africa									
Proved									
Developed Producing	1						2		1
Developed Non-Producing	26						—		26
Undeveloped	19						5		19
Total Proved	45						7		46
Probable	11						4		11
Total Proved plus Probable	56						11		57
Total Company									
Proved									
Developed Producing	121	130	188	684	835	7,043	5,861	229	10,207
Developed Non-Producing	28	6	—	42	—	—	272	13	135
Undeveloped	160	92	55	2,603	14	91	11,873	575	5,568
Total Proved	309	228	243	3,330	849	7,134	18,006	817	15,910
Probable	118	105	107	1,845	46	554	9,969	404	4,840
Total Proved plus Probable	427	333	349	5,175	895	7,688	27,974	1,221	20,750

Summary of Company Net Reserves

As of December 31, 2025
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Thermal Bitumen (MMbbl)	Mining Bitumen (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America									
Proved									
Developed Producing	104	107	150	518	649	5,831	5,308	185	8,427
Developed Non-Producing	2	5	—	32	—	—	246	11	91
Undeveloped	112	76	43	1,970	4	45	10,400	452	4,436
Total Proved	218	188	193	2,520	653	5,876	15,954	648	12,955
Probable	83	83	77	1,371	31	440	8,511	291	3,794
Total Proved plus Probable	301	272	270	3,891	684	6,315	24,465	939	16,749
North Sea									
Proved									
Developed Producing	—						—		—
Developed Non-Producing	—						—		—
Undeveloped	—						—		—
Total Proved	—						—		—
Probable	—						—		—
Total Proved plus Probable	—						—		—
Offshore Africa									
Proved									
Developed Producing	1						2		1
Developed Non-Producing	24						—		24
Undeveloped	14						4		15
Total Proved	39						6		40
Probable	8						3		8
Total Proved plus Probable	47						9		48
Total Company									
Proved									
Developed Producing	104	107	150	518	649	5,831	5,310	185	8,428
Developed Non-Producing	26	5	—	32	—	—	246	11	116
Undeveloped	127	76	43	1,970	4	45	10,403	452	4,451
Total Proved	257	188	193	2,520	653	5,876	15,960	648	12,995
Probable	91	83	77	1,371	31	440	8,514	291	3,803
Total Proved plus Probable	348	272	270	3,891	684	6,315	24,473	939	16,797

Reconciliation of Company Gross Reserves

As of December 31, 2025
Forecast Prices and Costs

TOTAL PROVED

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Thermal Bitumen (MMbbl)	Mining Bitumen (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2024	190	219	255	3,312	—	7,663	16,880	713	15,165
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	16	12	—	66	—	—	113	8	121
Infill Drilling	2	17	1	9	—	—	191	36	97
Improved Recovery	—	1	3	—	—	2	—	—	6
Acquisitions	68	—	—	—	427	—	1,153	74	760
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(4)	(4)	(3)	—	—	—	(99)	(4)	(32)
Technical Revisions	15	15	2	43	426	(328)	687	28	316
Production	(22)	(32)	(16)	(100)	(4)	(202)	(926)	(38)	(568)
December 31, 2025	264	228	243	3,330	849	7,134	17,999	817	15,864
North Sea									
December 31, 2024	6						3		7
Discoveries	—						—		—
Extensions	—						—		—
Infill Drilling	—						—		—
Improved Recovery	—						—		—
Acquisitions	—						—		—
Dispositions	—						—		—
Economic Factors	—						—		—
Technical Revisions	(3)						(2)		(3)
Production	(3)						(1)		(3)
December 31, 2025	—						—		—
Offshore Africa									
December 31, 2024	56						20		60
Discoveries	—						—		—
Extensions	—						—		—
Infill Drilling	—						—		—
Improved Recovery	—						—		—
Acquisitions	—						—		—
Dispositions	—						—		—
Economic Factors	—						—		—
Technical Revisions	(10)						(11)		(12)
Production	(1)						(2)		(2)
December 31, 2025	45						7		46
Total Company									
December 31, 2024	252	219	255	3,312	—	7,663	16,904	713	15,231
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	16	12	—	66	—	—	113	8	121
Infill Drilling	2	17	1	9	—	—	191	36	97
Improved Recovery	—	1	3	—	—	2	—	—	6
Acquisitions	68	—	—	—	427	—	1,153	74	760
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(4)	(4)	(3)	—	—	—	(99)	(4)	(32)
Technical Revisions	1	15	2	43	426	(328)	674	28	300
Production	(26)	(32)	(16)	(100)	(4)	(202)	(930)	(38)	(573)
December 31, 2025	309	228	243	3,330	849	7,134	18,006	817	15,910

TOTAL PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Thermal Bitumen (MMbbl)	Mining Bitumen (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2024	76	99	105	1,878	—	593	10,236	403	4,859
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	6	8	—	23	—	—	54	4	50
Infill Drilling	—	9	1	2	—	—	134	18	53
Improved Recovery	—	—	1	—	—	—	—	—	2
Acquisitions	31	—	—	—	23	—	315	21	127
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(1)	(1)	1	—	—	—	—	—	—
Technical Revisions	(6)	(10)	(2)	(58)	23	(39)	(775)	(42)	(262)
Production	—	—	—	—	—	—	—	—	—
December 31, 2025	107	105	107	1,845	46	554	9,965	404	4,828
North Sea									
December 31, 2024	1						1		1
Discoveries	—						—		—
Extensions	—						—		—
Infill Drilling	—						—		—
Improved Recovery	—						—		—
Acquisitions	—						—		—
Dispositions	—						—		—
Economic Factors	—						—		—
Technical Revisions	(1)						(1)		(1)
Production	—						—		—
December 31, 2025	—						—		—
Offshore Africa									
December 31, 2024	16						15		19
Discoveries	—						—		—
Extensions	—						—		—
Infill Drilling	—						—		—
Improved Recovery	—						—		—
Acquisitions	—						—		—
Dispositions	—						—		—
Economic Factors	—						—		—
Technical Revisions	(6)						(11)		(8)
Production	—						—		—
December 31, 2025	11						4		11
Total Company									
December 31, 2024	94	99	105	1,878	—	593	10,252	403	4,879
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	6	8	—	23	—	—	54	4	50
Infill Drilling	—	9	1	2	—	—	134	18	53
Improved Recovery	—	—	1	—	—	—	—	—	2
Acquisitions	31	—	—	—	23	—	315	21	127
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(1)	(1)	1	—	—	—	—	—	—
Technical Revisions	(13)	(10)	(2)	(58)	23	(39)	(788)	(42)	(271)
Production	—	—	—	—	—	—	—	—	—
December 31, 2025	118	105	107	1,845	46	554	9,969	404	4,840

TOTAL PROVED PLUS PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Thermal Bitumen (MMbbl)	Mining Bitumen (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2024	266	318	360	5,190	—	8,255	27,116	1,116	20,024
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	22	20	—	89	—	—	167	12	171
Infill Drilling	2	26	3	11	—	—	325	54	149
Improved Recovery	—	1	4	—	—	2	—	—	7
Acquisitions	99	—	—	—	450	—	1,469	95	888
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(5)	(5)	(2)	—	—	—	(99)	(4)	(32)
Technical Revisions	9	5	—	(15)	449	(367)	(88)	(14)	54
Production	(22)	(32)	(16)	(100)	(4)	(202)	(926)	(38)	(568)
December 31, 2025	371	333	349	5,175	895	7,688	27,964	1,221	20,693
North Sea									
December 31, 2024	7						5		8
Discoveries	—						—		—
Extensions	—						—		—
Infill Drilling	—						—		—
Improved Recovery	—						—		—
Acquisitions	—						—		—
Dispositions	—						—		—
Economic Factors	—						—		—
Technical Revisions	(4)						(4)		(4)
Production	(3)						(1)		(3)
December 31, 2025	—						—		—
Offshore Africa									
December 31, 2024	73						36		79
Discoveries	—						—		—
Extensions	—						—		—
Infill Drilling	—						—		—
Improved Recovery	—						—		—
Acquisitions	—						—		—
Dispositions	—						—		—
Economic Factors	—						—		—
Technical Revisions	(16)						(22)		(20)
Production	(1)						(2)		(2)
December 31, 2025	56						11		57
Total Company									
December 31, 2024	346	318	360	5,190	—	8,255	27,156	1,116	20,110
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	22	20	—	89	—	—	167	12	171
Infill Drilling	2	26	3	11	—	—	325	54	149
Improved Recovery	—	1	4	—	—	2	—	—	7
Acquisitions	99	—	—	—	450	—	1,469	95	888
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(5)	(5)	(2)	—	—	—	(99)	(4)	(32)
Technical Revisions	(11)	5	—	(15)	449	(367)	(114)	(14)	29
Production	(26)	(32)	(16)	(100)	(4)	(202)	(930)	(38)	(573)
December 31, 2025	427	333	349	5,175	895	7,688	27,974	1,221	20,750

Notes to Reserves Tables

1. "Company gross reserves" are the Company's working interest share of reserves before deduction of royalties and without including any royalty interests of the Company.
2. "Company net reserves" are the company gross reserves less all royalties payable to others plus royalties receivable from others.
3. References to "light and medium crude oil" means "light crude oil and medium crude oil combined".
4. "Reserves" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical, and engineering data, with the use of established technology and under 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 which can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
   - "Probable reserves" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

   - "Developed reserves" are reserves that are expected to be recovered from (i) existing wells and installed facilities or, if the facilities have not been installed, that would involve a low expenditure (compared to the cost of drilling a well) to put the reserves on production, and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. The developed category may be subdivided into producing and non-producing.
   - "Undeveloped reserves" are reserves that are expected to be recovered from known accumulations with new wells on undrilled acreage, or from existing wells where significant expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units directly offsetting development spacing areas that are reasonably certain of production when drilled unless reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
5. The reserves evaluation involved data supplied by the Company with respect to geological and engineering data, product price adjustments for product quality, heating value and transportation, interests owned, royalties payable, production costs, capital costs and contractual commitments. This data was found by the IQRE to be reasonable.
6. Reserves reconciliation change category definitions:
   - "Discoveries" means additions to reserves in reservoirs where no reserves were previously booked.
   - "Extensions" means additions to reserves resulting from step-out drilling or recompletions.
   - "Infill Drilling" means additions to reserves resulting from drilling or recompletions within the known boundaries of a reservoir.
   - "Improved Recovery" means additions to reserves resulting from the implementation of improved recovery schemes.
   - "Economic Factors" means changes primarily due to price forecasts.
   - "Technical Revisions" include changes in previous estimates resulting from new technical data or revised interpretations and changes in operating costs, capital costs and offsets to product reference pricing.
7. 2025 reserves reconciliation highlights:

   Total Proved Crude Oil, Thermal Bitumen, Mining Bitumen, SCO and NGLs reserves increased by 496 MMbbl:

   - Extensions: Increase of 103 MMbbl primarily due to extension drilling/future offset additions at various Thermal Bitumen, Light Crude Oil, Primary Heavy Crude Oil and natural gas (NGLs) properties.
   - Infill Drilling: Increase of 65 MMbbl primarily due to infill drilling/future offset additions at various natural gas (NGLs), Primary Heavy Crude Oil, Thermal Bitumen, Light Crude Oil and Pelican Lake Heavy Crude Oil properties.
   - Improved Recovery: Increase of 6 MMbbl primarily due to increased recovery at Pelican Lake Heavy Crude Oil, Oil Sands Mining and Upgrading (SCO) and various Primary Heavy Crude Oil properties.
   - Acquisitions: Increase of 568 MMbbl primarily due to acquisitions at Oil Sands Mining and Upgrading (Mining Bitumen), various natural gas (NGLs) and Light Crude Oil properties.
   - Economic Factors: Decrease of 15 MMbbl due to changes in product pricing.

- Technical Revisions: Increase of 188 MMbbl primarily due to improved performance at Oil Sands Mining and Upgrading (Mining Bitumen and SCO), various Thermal Bitumen, natural gas (NGLs), Primary Heavy Crude Oil, Pelican Lake Heavy Crude Oil and Light Crude Oil properties, partially offset by a category transfer at Oil Sands Mining and Upgrading from SCO to Bitumen Mining.
- Production: Decrease of 418 MMbbl.

Total Proved Natural Gas reserves increased by 1,102 Bcf:

- Extensions: Increase of 113 Bcf primarily due to extension drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Infill Drilling: Increase of 191 Bcf primarily due to infill drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Acquisitions: Increase of 1,153 Bcf primarily due to acquisitions at various Natural Gas properties.
- Economic Factors: Decrease of 99 Bcf due to lower product pricing.
- Technical Revisions: Increase of 674 Bcf primarily due to positive revisions in various North America core areas as a result of improved performance and category transfers from probable to proved reserves.
- Production: Decrease of 930 Bcf.

Total Proved plus Probable Crude Oil, Thermal Bitumen, Mining Bitumen, SCO and NGLs reserves increased by 504 MMbbl:

- Extensions: Increase of 143 MMbbl primarily due to extension drilling/future offset additions at various Thermal Bitumen, Light Crude Oil, Primary Heavy Crude Oil and natural gas (NGLs) properties.
- Infill Drilling: Increase of 95 MMbbl primarily due to infill drilling/future offset additions at various natural gas (NGLs), Primary Heavy Crude Oil, Thermal Bitumen, Pelican Lake Heavy Crude Oil and Light Crude Oil properties.
- Improved Recovery: Increase of 7 MMbbl primarily due to increased recovery at Pelican Lake Heavy Crude Oil, Oil Sands Mining and Upgrading (SCO) and various Primary Heavy Crude Oil properties.
- Acquisitions: Increase of 643 MMbbl primarily due to acquisitions at Oil Sands Mining and Upgrading (Mining Bitumen), various Light Crude Oil and natural gas (NGLs) properties.
- Economic Factors: Decrease of 15 MMbbl due to changes in product pricing.
- Technical Revisions: Increase of 48 MMbbl primarily due to mine plan changes at Oil Sands Mining and Upgrading (Mining Bitumen and SCO), and performance at various Primary Heavy Crude Oil properties, partially offset by decreased performance at various Light Crude Oil, Thermal Bitumen and natural gas (NGLs) properties, and by a category transfer at Oil Sands Mining and Upgrading from SCO to Mining Bitumen.
- Production: Decrease of 418 MMbbl.

Total Proved plus Probable Natural Gas reserves increased by 818 Bcf:

- Extensions: Increase of 167 Bcf primarily due to extension drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Infill Drilling: Increase of 325 Bcf primarily due to infill drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Acquisitions: Increase of 1,469 Bcf primarily due to acquisitions at various Natural Gas properties.
- Economic Factors: Decrease of 99 Bcf due to lower product pricing.
- Technical Revisions: Decrease of 114 Bcf primarily due to negative revisions at various Natural Gas properties.
- Production: Decrease of 930 Bcf.

8. A report on reserves data by the IQREs is provided in Schedule "A" to this AIF. A report by the Company's management and directors on crude oil, natural gas and NGLs reserves disclosure is provided in Schedule "B" to this AIF.

Future Net Revenue Tables and Notes

The following tables summarize the future net revenue as of December 31, 2025 using forecast prices and costs. Abandonment, Decommissioning and Reclamation ("ADR") costs included in the calculation of future net revenue consist of both the Company's total North America and Offshore Africa Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as of December 31, 2025 and forecast estimates of ADR costs attributable to future development activity.

Summary of Net Present Values of Future Net Revenue Before Income Taxes

As of December 31, 2025
Forecast Prices and Costs

($ millions)	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%	Unit Value Discounted at 10%/year ($/BOE)
North America						
Proved						
Developed Producing	447,601	187,808	110,334	78,141	61,182	13.09
Developed Non-Producing	3,196	1,465	920	674	535	10.08
Undeveloped	179,363	83,964	45,436	27,356	17,785	10.24
Total Proved	630,159	273,238	156,690	106,170	79,502	12.10
Probable	199,626	68,282	32,848	19,793	13,705	8.66
Total Proved plus Probable	829,786	341,519	189,539	125,963	93,207	11.32
Offshore Africa						
Proved						
Developed Producing	(454)	(296)	(220)	(181)	(160)	(254.23)
Developed Non-Producing	1,050	818	651	527	432	26.68
Undeveloped	1,239	892	659	498	381	44.40
Total Proved	1,835	1,413	1,091	844	653	27.19
Probable	767	533	382	282	213	45.83
Total Proved plus Probable	2,602	1,946	1,473	1,126	867	30.40
Total Company						
Proved						
Developed Producing	447,147	187,512	110,114	77,960	61,023	13.07
Developed Non-Producing	4,246	2,283	1,572	1,201	967	13.58
Undeveloped	180,602	84,856	46,096	27,853	18,166	10.36
Total Proved	631,994	274,651	157,781	107,014	80,156	12.14
Probable	200,394	68,814	33,231	20,075	13,918	8.74
Total Proved plus Probable	832,388	343,465	191,012	127,089	94,074	11.37

Summary of Net Present Values of Future Net Revenue After Income Taxes

As of December 31, 2025
Forecast Prices and Costs

($ millions)	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	348,517	147,295	87,094	61,977	48,694
Developed Non-Producing	2,590	1,132	697	504	396
Undeveloped	137,593	63,572	33,795	19,890	12,574
Total Proved	488,700	211,999	121,586	82,371	61,663
Probable	153,006	52,118	24,966	14,985	10,342
Total Proved plus Probable	641,706	264,117	146,552	97,355	72,005
Offshore Africa					
Proved					
Developed Producing	(456)	(299)	(222)	(183)	(162)
Developed Non-Producing	962	750	597	482	395
Undeveloped	936	679	505	382	292
Total Proved	1,442	1,131	880	682	525
Probable	574	399	286	211	159
Total Proved plus Probable	2,016	1,530	1,167	893	684
Total Company					
Proved					
Developed Producing	348,061	146,996	86,872	61,794	48,532
Developed Non-Producing	3,552	1,882	1,294	986	790
Undeveloped	138,529	64,251	34,301	20,272	12,866
Total Proved	490,142	213,130	122,466	83,052	62,188
Probable	153,581	52,517	25,252	15,196	10,501
Total Proved plus Probable	643,722	265,647	147,718	98,248	72,689

Total Future Net Revenue (Undiscounted)

As of December 31, 2025
Forecast Prices and Costs

	North America		Offshore Africa		Total Company	
($ millions)	Total Proved	Total Proved plus Probable	Total Proved	Total Proved plus Probable	Total Proved	Total Proved plus Probable
Revenue	1,515,698	1,923,661	4,157	5,024	1,519,855	1,928,685
Royalties	285,418	375,998	142	183	285,561	376,181
Production Costs	471,315	564,057	1,042	1,030	472,357	565,088
Development Costs	105,432	129,200	643	705	106,074	129,906
ADR Costs for Future Development	1,518	2,159	33	42	1,552	2,201
Future Net Revenue Before Income Taxes **Excluding ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)**	652,015	852,246	2,296	3,063	654,311	855,309
ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	21,855	22,460	462	462	22,317	22,921
Future Net Revenue Before Income Taxes **Including ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)**	630,159	829,786	1,835	2,602	631,994	832,388
Income Taxes	141,460	188,080	393	586	141,852	188,665
Future Net Revenue After Income Taxes	488,700	641,706	1,442	2,016	490,142	643,722

Future Net Revenue By Product Type

As of December 31, 2025
Forecast Prices and Costs

Total Proved Product Type	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($ millions)	Unit Value ($/BOE)
Light and Medium Crude Oil (including solution gas and other by-products)	8,733	16.00
Primary Heavy Crude Oil (including solution gas)	4,057	20.89
Pelican Lake Heavy Crude Oil (including solution gas)	3,219	16.66
Thermal Bitumen	35,726	14.18
Mining Bitumen	6,086	9.32
Synthetic Crude Oil	86,101	14.65
Natural Gas (including by-products but excluding solution gas and by-products from crude oil wells)	18,434	6.12
Total Excluding ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	162,356	12.49
ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	(4,575)	
Total Including ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	**157,781**	**12.14**

Total Proved plus Probable Product Type	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($ millions)	Unit Value ($/BOE)
Light and Medium Crude Oil (including solution gas and other by-products)	12,339	16.70
Primary Heavy Crude Oil (including solution gas)	6,055	21.65
Pelican Lake Heavy Crude Oil (including solution gas)	4,281	15.83
Thermal Bitumen	44,943	11.55
Mining Bitumen	6,527	9.54
Synthetic Crude Oil	93,211	14.76
Natural Gas (including by-products but excluding solution gas and by-products from crude oil wells)	28,277	6.12
Total Excluding ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	195,633	11.65
ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	(4,621)	
Total Including ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	191,012	11.37

Notes to Future Net Revenue Tables

1. Abandonment, Decommissioning and Reclamation ("ADR") costs included in the calculation of the future net revenue consist of both the Company's total North America and Offshore Africa Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as of December 31, 2025 and forecast estimates of ADR costs attributable to future development activity. The Company's total North America and Offshore Africa ARO included in the reserves future net revenue is escalated at the rate of inflation described in the "Pricing Assumptions" section of this AIF.
2. For reserves in Canada, future net revenue includes carbon cost compliance in accordance with provincial GHG policies. In British Columbia and Manitoba, carbon costs will reach $170/tonne in 2030, in Alberta, $130/tonne in 2028 (as informed by the November 2025 MOU between the federal and Alberta governments), and in Saskatchewan there is currently no carbon pricing in effect. Refer to the "Regulatory Matters" section of this AIF for further details on GHG policies.
3. Unit values ($/BOE) are based on company net reserves.
4. After-tax net present values consider the Company's existing tax pool balances and current tax regulations and do not represent an estimate of the value at the consolidated entity level, which may be significantly different. For information at the consolidated entity level, refer to the Company's Consolidated Financial Statements for the year ended December 31, 2025 and the annual MD&A for the year ended December 31, 2025, dated March 4, 2026.
5. Future net revenue is prior to provision for interest, general and administrative expenses, and the impact of any risk management activities.

Pricing Assumptions

The crude oil, natural gas and NGLs reference pricing and the inflation and exchange rates used in the preparation of reserves and related future net revenue estimates are as per the 3-consultant-average of price forecasts developed by Sproule ERCE, GLJ and McDaniel & Associates Consultants Ltd. ("McDaniel"), dated December 31, 2025. The following is a summary of the 3-consultant-average price forecast. All prices increase at a rate of 2% per year after 2030.

		2026	2027	2028	2029	2030
Crude Oil and NGLs						
WTI	US$/bbl	59.92	65.10	70.28	71.93	73.37
WCS	C$/bbl	65.13	70.43	76.90	78.71	80.29
Canadian Light Sweet	C$/bbl	77.54	83.60	90.17	92.32	94.17
Cromer LSB	C$/bbl	75.09	81.56	86.95	89.19	90.98
Edmonton C5+	C$/bbl	80.01	86.19	92.83	95.04	96.94
Brent	US$/bbl	63.92	69.13	74.36	76.10	77.62
Natural Gas						
AECO	C$/MMBtu	3.00	3.30	3.49	3.58	3.65
BC Westcoast Station 2	C$/MMBtu	2.66	3.07	3.25	3.34	3.41
Henry Hub	US$/MMBtu	3.74	3.78	3.85	3.93	4.01

Notes to Pricing Assumptions Table

1. Reference pricing definitions:
   - "WTI" refers to the price of West Texas Intermediate crude oil at Cushing, Oklahoma.
   - "WCS" refers to Western Canadian Select, a blend of heavy crude oils and bitumen with sweet synthetic and condensate diluents at Hardisty, Alberta; reference price used in the preparation of primary heavy crude oil, Pelican Lake heavy crude oil, thermal bitumen and mining bitumen reserves.
   - "Canadian Light Sweet" refers to the price of light gravity (40 º API), low sulphur content Mixed Sweet Blend (MSW) crude oil at Edmonton, Alberta; reference price used in the preparation of light and medium crude oil and SCO reserves.
   - "Cromer LSB" refers to the price of light sour blend (35 º API) physical crude oil at Cromer, Manitoba; reference price used in the preparation of light and medium crude oil in SE Saskatchewan and SW Manitoba reserves.
   - "Edmonton C5+" refers to pentanes plus at Edmonton, Alberta; reference price used in the preparation of NGLs reserves; also used in determining the diluent costs associated with primary heavy crude oil and thermal bitumen reserves.
   - "Brent" refers to the benchmark price for European, African and Middle Eastern crude oil; reference price used in the preparation of Offshore Africa light crude oil reserves.

- "AECO" refers to the Alberta natural gas trading price at the AECO-C hub in southeast Alberta; reference price used in the preparation of North America (excluding British Columbia) natural gas reserves.
- "BC Westcoast Station 2" refers to the natural gas delivery point on the Enbridge Inc. system at Chetwynd, British Columbia; reference price used in the preparation of British Columbia natural gas reserves.
- "Henry Hub" refers to a distribution hub on the natural gas pipeline system in Erath, Louisiana and is the pricing point for natural gas futures on the New York Mercantile Exchange.

2. Effective April 1, 2021, the COGE Handbook includes price forecast guidelines for the preparation of commodity price forecasts for use in reserve evaluations. For year-end 2025, the methodology used by Sproule ERCE, GLJ and McDaniel for determining their price forecasts is consistent with the COGE Handbook guidelines.
3. The forecast prices and costs assume the continuance of current laws and regulations, and any increases in wellhead selling prices also take inflation into account. Sales prices are based on reference prices as detailed above and adjusted for quality and transportation on an individual property basis.
4. The Company's 2025 average pricing, net of blending costs and excluding risk management activities, was $87.45/bbl for light and medium crude oil, $73.74/bbl for primary heavy crude oil, $75.07/bbl for Pelican Lake heavy crude oil, $72.42/bbl for thermal bitumen, $53.16/bbl for mining bitumen, $87.10/bbl for SCO, $54.58/bbl for NGLs, and $2.51/Mcf for natural gas.
5. Production and capital costs are escalated at the 3-consultant-average cost inflation rate of 0% per year for 2026 and 2% per year for 2027 and beyond for all products.
6. The 3-consultant-average foreign exchange rate used in the 2025 evaluation was 0.7277 US$/C$ for 2026, 0.7367 US$/C$ for 2027 and 0.7400 US$/C$ for 2028 and beyond.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are reserves expected to be recovered from known accumulations and require significant expenditure to develop and make capable of production. Undeveloped reserves additions result from one or more of the following: acquisitions, infill and extension drilling, or improved recovery in the year when the events first occurred. Proved and probable undeveloped reserves were estimated by the IQRE in accordance with the procedures and standards contained in the COGE Handbook.

Proved Undeveloped

Year	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Thermal Bitumen (MMbbl)	Mining Bitumen (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
2023									
First Attributed	26	24	—	68	—	35	2,063	82	579
Total	100	80	55	2,596	—	83	10,045	398	4,986
2024									
First Attributed	32	22	—	56	—	—	1,982	166	607
Total	129	88	53	2,603	—	96	11,625	533	5,440
2025									
First Attributed	47	22	—	82	—	—	905	96	398
Total	160	92	55	2,603	14	91	11,873	575	5,568

Probable Undeveloped

Year	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Thermal Bitumen (MMbbl)	Mining Bitumen (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
2023									
First Attributed	13	15	—	30	—	18	1,076	43	299
Total	48	64	27	1,635	—	18	7,717	257	3,335
2024									
First Attributed	14	12	—	18	—	—	1,213	98	343
Total	58	65	28	1,630	—	18	8,569	340	3,567
2025									
First Attributed	26	15	1	22	—	—	283	35	145
Total	75	69	30	1,620	—	18	8,021	320	3,469

The assignment of some proved undeveloped and probable undeveloped reserves beyond 2 years is based on the Company's capital development plan to optimize operations and align capital investments with estimated future net revenue. The extended development timing has no consequential impact on the confidence level associated with the reserves estimate in each category. The IQRE reserves evaluation report documents the evaluation, assignment and justification for undeveloped reserves beyond the NI 51-101 development timing guidelines. The Company's justifications for reserves development timing beyond 2 years are summarized by product type below:

1. Light and Medium Crude Oil and Primary Heavy Crude Oil undeveloped reserves are located throughout the Company's core areas in western Canada and Offshore Africa. Development timing is justified to accommodate the following:
   - capital projects with facility constraints and development plans designed to optimize the operation and deliver production for the life of the facilities;
   - resource plays with extensive ongoing development;
   - EOR or waterflood projects with ongoing, extensive development opportunity;
   - strict ESG or regulatory development restrictions limit the development drilling that would otherwise proceed at a quicker pace; and
   - offshore projects with long lead times and facility constraints.
2. Pelican Lake Heavy Crude Oil is produced at a large heavy crude oil polymer EOR flood project with chemical and facility constraints. The development plan is designed to optimize the purchase and use of chemicals and deliver production for the life of the facilities.
3. Thermal Bitumen development plans are designed to optimize the operation and deliver production for the life of the facilities over the next fifty years.
4. Mining Bitumen and Synthetic Crude Oil reserves are associated with two large oil sands mining and upgrading projects with long lead times and facility constraints. The development plans are designed to optimize the operation and deliver production for the life of the facilities.
5. Natural Gas undeveloped reserves are located throughout the Company's core areas in western Canada. Development timing is justified to accommodate the following:
   - capital projects with facility constraints and development plans designed to optimize the operation and deliver production for the life of the facilities;
   - resource plays with extensive ongoing development; and
   - strict ESG or regulatory development restrictions limit the development drilling that would otherwise proceed at a quicker pace.

Significant Factors or Uncertainties Affecting Reserves Data

The development plan for the Company's undeveloped reserves is based on forecast price and cost assumptions. Projects may be advanced or delayed based on actual prices that occur.

The evaluation of reserves is a process that can be significantly affected by a number of internal and external factors. Revisions are often necessary resulting in changes in technical data acquired, historical performance, fluctuations in production costs, development costs and product pricing, economic conditions, changes in royalty regimes and environmental regulations, and future technology improvements. See "Uncertainty of Reserves Estimates" in the "Risk Factors" section of this AIF for further information.

Future Development Costs

The following table summarizes the undiscounted future development costs using the 3-consultant-average inflation and foreign exchange rates as of December 31, 2025. Future development costs exclude all Abandonment, Decommissioning and Reclamation ("ADR") costs. ADR costs are included in the calculation of the future net revenue and consist of both the Company's total North America and Offshore Africa Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as of December 31, 2025 and forecast estimates of ADR costs attributable to future development activity.

Future Development Costs (Undiscounted)

($ millions)	2026	2027	2028	2029	2030	Thereafter	Total	Total Discounted at 10%
Total Proved								
North America	4,580	5,250	5,371	5,915	5,432	78,883	105,432	40,346
Offshore Africa	400	50	22	17	24	130	643	532
Total Company	4,980	5,300	5,392	5,932	5,457	79,014	106,074	40,878
Total Proved plus Probable								
North America	4,741	5,503	5,646	6,247	5,746	101,318	129,200	45,531
Offshore Africa	453	59	22	17	24	130	705	590
Total Company	5,194	5,562	5,667	6,264	5,770	101,448	129,906	46,122

Management believes that internally generated cash flows, existing credit facilities and access to debt capital markets are sufficient to fund future development costs. The Company does not anticipate the costs of funding would make the development of any property uneconomic.

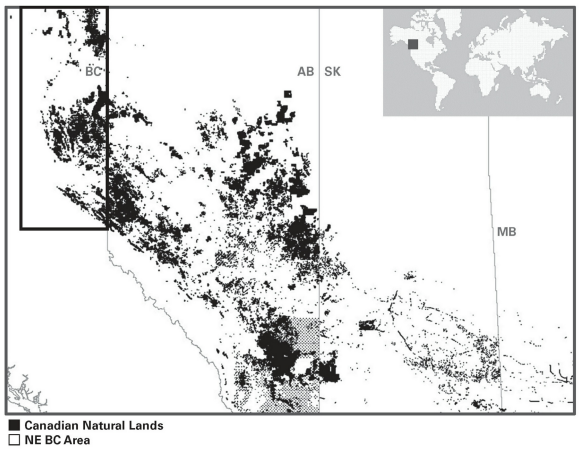
Other Oil and Gas Information

DAILY PRODUCTION

Set forth below is a summary of the production, before royalties, from crude oil, natural gas and NGLs properties for the fiscal years ended December 31, 2025 and 2024.

	2025 Average Daily Production Rates		2024 Average Daily Production Rates	
Region	**Crude Oil & NGLs (bbl)**	**Natural Gas (MMcf)**	Crude Oil & NGLs (bbl)	Natural Gas (MMcf)
North America				
Northeast British Columbia	22,769	958	23,170	882
Northwest Alberta	108,544	1,151	69,651	903
Northern Plains	412,134	165	401,549	168
Southern Plains	22,786	262	11,401	180
Southeast Saskatchewan	3,168	2	3,517	3
Oil Sands Mining & Upgrading	565,102	—	472,245	—
North America Total	1,134,503	2,538	981,533	2,136
International				
North Sea UK Sector	8,468	3	11,536	2
Offshore Africa	3,204	6	12,534	9
International Total	11,672	9	24,070	11
Company Total	1,146,175	2,547	1,005,603	2,147

Northeast British Columbia

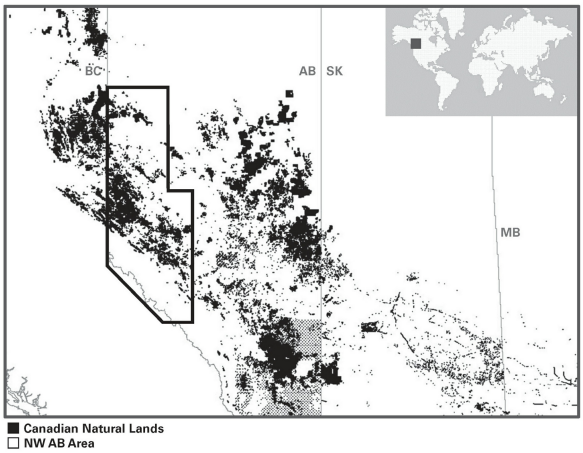


The northeast British Columbia region holds a significant portion of the Montney formation and provides exploration and development opportunities in combination with significant controlled infrastructure. The exploration strategy focuses on comprehensive evaluation through two dimensional seismic, three dimensional seismic and targeting economic prospects close to existing infrastructure.

This region includes the Septimus, Umbach/Nig and Townsend Montney natural gas assets with owned natural gas processing capacity as well as dedicated third party natural gas processing capacity.

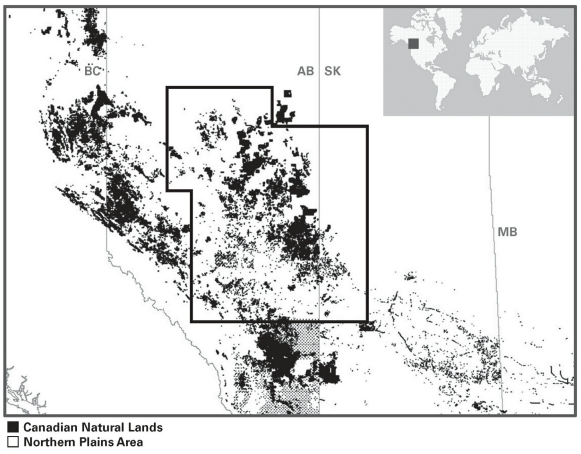
The southern portion of this region encompasses the Company's BC Foothills assets where natural gas is produced from the deep Mississippian and Triassic aged reservoirs in this highly structural area.

Northwest Alberta



This region is located west of Edmonton, Alberta along the border of British Columbia and Alberta and provides a premium land base in the deep basin, multi-zone, liquids-rich natural gas and light crude oil fairway. Northwest Alberta has a significant Duvernay, Montney and Spirit River land base, and provides exploration and development opportunities in combination with an extensive portfolio of owned and operated infrastructure. In this region, the Company produces light crude oil, NGLs and natural gas from multiple, often technically complex horizons, with formation depths ranging from 700 to 4,500 meters. Locations are identified with two dimensional and three dimensional seismic. The southwest portion of this region also contains significant Foothills assets with natural gas produced from the deep Mississippian and Triassic aged reservoirs.

Northern Plains



This region starts south of Edmonton, Alberta and extends north to Fort McMurray, Alberta and from northwest Alberta into western Saskatchewan. Over most of the region, both sweet and sour natural gas reserves are produced from numerous productive horizons at depths up to approximately 1,500 meters. In the southwest portion of the region, light crude oil and NGLs are also encountered at slightly greater depths. The Company targets low-risk exploration and development opportunities in this area.

Near the Lloydminster, Bonnyville and Slave Lake areas of Alberta, reserves of primary heavy crude oil (averaging 10°-14° API) and natural gas are produced through vertical, slant and horizontal well bores from a number of productive horizons at depths up to 1,000 meters. The crude oil viscosity and the reservoir quality will determine the amount of crude oil produced from the reservoir. A key component to maintaining profitability in the production of heavy crude oil is to be an effective and efficient producer. The Company continues to control costs by holding a dominant position that includes a significant land base and an extensive infrastructure of batteries and disposal facilities.

In this region, the Company's holdings of primary heavy crude oil production are the result of Crown land purchases and acquisitions. The Company's 100% owned ECHO Pipeline system is also located in this region. The ECHO Pipeline has a capacity of up to 78,000 bbl/d, which enables the Company to transport its own production volumes at a reduced production cost. This pipeline enhances the Company's ability to control the full spectrum of costs associated with the development and marketing of its heavy crude oil.

Included in the northern part of this region, approximately 325 kilometers north of Edmonton, Alberta are the Company's holdings at Pelican Lake. These assets produce Pelican Lake heavy crude oil from the Wabiskaw formation with gravities of 12°-17° API. Production expenses are low due to the gathering and pipeline facilities in place. The Company has the major ownership position in the necessary infrastructure, roads, drilling pads, gathering and sales pipelines, batteries, gas plants and compressors, to ensure economic development of the large crude oil pool located on the lands, including the 100% owned and operated Pelican Lake Pipeline and three major oil batteries with a capacity of 85,000 bbl/d. The Company is using an EOR scheme through polymer flooding to increase the ultimate recoveries from the field.

Production of thermal bitumen from the 100% owned Primrose and Wolf Lake fields located near Bonnyville, Alberta, involves processes that utilize steam to increase the recovery of the bitumen. The processes employed by the Company are CSS, SAGD and steamflood. These recovery processes inject steam to heat the bitumen deposits, reducing the viscosity and thereby improving its flow characteristics. There is also an infrastructure of gathering systems and a processing plant at Wolf Lake with capacity of 140,000 bbl/d. The Company holds a 50% interest in a co-generation facility capable of producing 84 megawatts of electricity. The Company continues to optimize the CSS, and steamflood processes which results in significant improvements in well productivity and in ultimate bitumen recovery.

The Company has two 100% owned thermal SAGD facilities in the Kirby area located near Lac La Biche, Alberta with infrastructure and total plant processing capacity of 80,000 bbl/d. Solvent injection commenced at the Company's commercial scale solvent SAGD pad at Kirby North in June 2024 and all 8 wells are now injecting solvent.

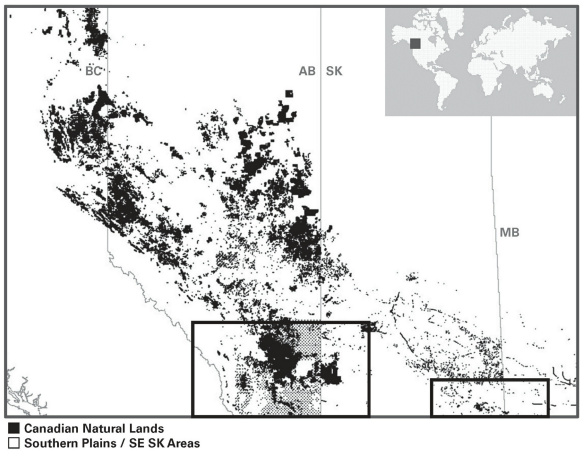
The Company has a 100% interest in the operating thermal SAGD assets at Jackfish and in the Pike lands located adjacent to Jackfish. The infrastructure at Jackfish consists of three processing plants and gathering systems that have a combined capacity of 120,000 bbl/d. Drilling and pipeline development in support of the Pike 1 project commenced in late 2024 with the Company drilling two SAGD pads in 2025, which are tied into the existing Jackfish facilities. The first of these two pads began production in late 2025 with the second targeted to come on production in the second quarter of 2026 and are expected to keep the Jackfish plants at full capacity.

Southern Plains and Southeast Saskatchewan

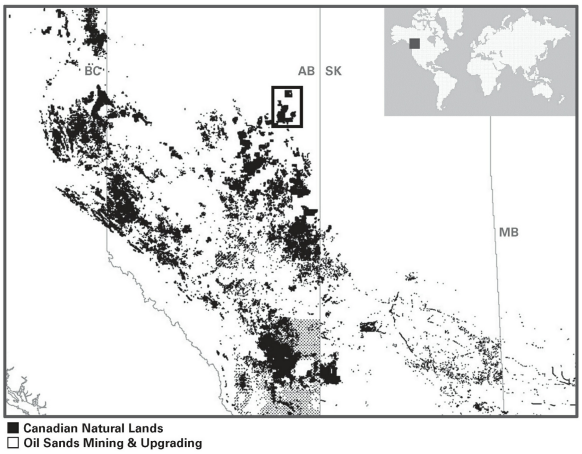
The Southern Plains region is principally located south of the Northern Plains region to the United States border and extending into western Saskatchewan.

Reserves of natural gas, NGLs and light and medium crude oil are contained in numerous productive horizons at depths up to 2,300 meters. This region is one of the more mature regions of the Western Canadian Sedimentary Basin and requires continual operational cost control through efficient utilization of existing facilities, flexible infrastructure design and consolidation of interests where appropriate.

The Southeast Saskatchewan area is located in the southeastern portion of the province extending into Manitoba and produces primarily light sour crude oil from multiple productive horizons found at depths up to 2,700 meters.



Oil Sands Mining and Upgrading



Horizon: The Company owns a 100% working interest in its Horizon leases which are located about 70 kilometers north of Fort McMurray, Alberta. In 2021, the Company completed an acquisition of a 5% net carried interest on an existing Company oil sands lease.

The oil sands resource at Horizon is found in the Cretaceous McMurray Formation, which is further subdivided into three informal members: lower, middle and upper. Most of Horizon's oil sands resource is found within the lower and middle McMurray Formation at depths ranging from 50 to 100 meters below the surface.

Horizon, which is accessible by private road and private airstrip, includes surface oil sands mining, bitumen extraction, bitumen upgrading and associated infrastructure. Mining of the oil sands is done using conventional truck and shovel technology. The ore is then processed through extraction and froth treatment facilities to produce bitumen, which is upgraded on-site into SCO. The SCO is transported from the site by pipeline to the Edmonton area for distribution. Two on-site cogeneration plants with a combined design capacity of 180 megawatts provide power and steam for operations.

The Company received project sanction by the Board of Directors in 2005, authorizing management to proceed with Phase 1 of Horizon with a design capacity of 110,000 bbl/d. First SCO production was achieved during 2009. Subsequently, the Company completed the Phase 2A coker plant tie-in in 2014, followed by completion of the Phase 2B expansion in 2016 and completion of the Phase 3 expansion in 2017, bringing total production capacity to approximately 250,000 bbl/d. In 2018, the Company acquired the Joslyn oil sands project, adding to the Company's total oil sands mining and upgrading reserves. The incorporation of the Joslyn leases (now, Horizon South) to the mine plan has allowed mining to continue south of the previously existing Horizon leases with opportunity for further cost optimizations. In 2024, the Company completed a reliability enhancement project at Horizon, which extended the turnaround interval from annually to every second year, bringing total annual average production capacity to approximately 264,000 bbl/d.

AOSP: In 2017, the Company acquired a 70% interest in AOSP, an oil sands mining and upgrading joint venture located in Alberta, Canada. In 2024, the Company acquired a further 20% interest in AOSP, bringing the Company's ownership to 90%. In 2025, the Company acquired the remaining 10% interest in the AOSP mines in exchange for a 10% working interest in the non-operated Scotford Upgrader and Quest. Following the close of the transaction, the Company has a 100% interest in the AOSP mines and an 80% interest in the Scotford Upgrader and Quest. AOSP's mining and extraction assets are located in the Athabasca region near Fort McMurray, Alberta, and include the Muskeg River and Jackpine mines. Shell operates the Scotford Upgrader, including the Quest project, which is located near Fort Saskatchewan, northeast of Edmonton, Alberta and utilizes LC FINING technology to efficiently hydrocrack residuum to high-quality fuel oils and transportation fuels.

Bitumen is produced from the oil sands deposits using conventional truck and shovel technology. The ore is then processed through extraction and froth treatment facilities to produce bitumen. Diluted bitumen blend from the Muskeg River and Jackpine mines is transported to the Scotford Upgrader on the third party owned Corridor Pipeline where the bitumen is upgraded into Premium Albian Synthetic crude oil, Albian Heavy Synthetic crude oil and Vacuum Gas Oil and, in certain circumstances, other heavy blends. Diluent is transported from the Scotford Upgrader back to the Muskeg River mine through the combined Corridor Pipeline transport system. A long term off-take agreement is in place with Shell to purchase Vacuum Gas Oil at market rates as well as agreements to sell volumes of Premium Albian Synthetic and Albian Heavy Synthetic from the Scotford Upgrader at market rates.

In 2024, a debottlenecking project at the Scotford Upgrader was completed bringing the gross production capacity of AOSP to approximately 328,000 bbl/d. Shell obtained the Joint Review Panel Approval along with other associated approvals in 2013 for a 100,000 bbl/d expansion of the Jackpine Mine and in 2019 the remaining major application approvals were obtained.

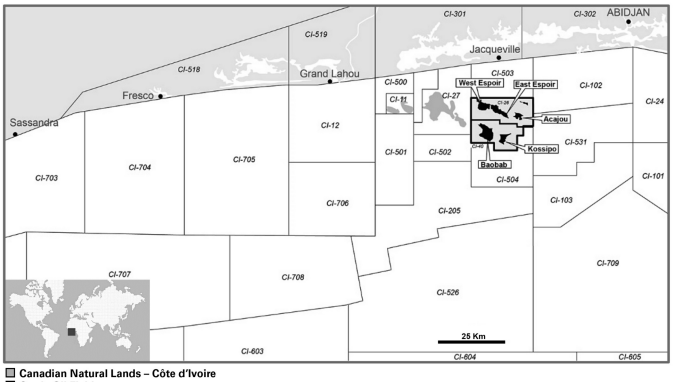
United Kingdom North Sea

The Company, through its wholly owned subsidiary, CNR International (U.K.) Limited, formerly Ranger Oil (U.K.) Limited, has operated in the North Sea for over 40 years, developing a significant database, extensive operating experience and an experienced staff. In recent years, due to the prevailing regulatory and economic conditions and increasingly challenging commercial outlook in the United Kingdom, the Company determined that the Ninian, Columba, Lyell and Strathspey fields were no longer economic and de-booked associated crude oil and natural gas reserves as at December 31, 2022. During 2025, the Company determined that T-block (comprising the Tiffany, Toni and Thelma fields) was no longer economic and de-booked associated crude oil and natural gas reserves as at December 31, 2025 . The Company is in the process of winding down and decommissioning all of its remaining North Sea assets and operations, including the relinquishment of associated licenses back to the UK government.

Notwithstanding the decommissioning activities, four crude oil fields remained in production at the end of 2025 including Ninian Central, located in the northern portion of the North Sea where the Company holds a 100% operated working interest, and T-block (comprising the Tiffany, Toni and Thelma fields), located in the central portion of the North Sea where the Company holds a 100% operated working interest. The Company also continues to receive tariff revenue from third parties for the processing of crude oil and natural gas through the Ninian Central platform.

Offshore Africa

Côte d'Ivoire



The Company owns interests in two licences located offshore Côte d'Ivoire ("CDI"). The first is a 58.7% operated working interest in the Espoir field in Block CI-26 which is located in water depths ranging from 100 to 700 meters. Production from East Espoir commenced in 2002 and from West Espoir in 2006. Crude oil from the East and West Espoir fields is produced to a dedicated floating production storage and offloading vessel ("FPSO") with the associated natural gas delivered onshore for local power generation through a subsea pipeline. The CI-26 Exclusive Exploitation Authorization ("EEA") license expires on July 24, 2026. During 2025, the Company determined that further development at Espoir was not economic and advised the CDI government that it will not be seeking an extension of the licence. Under the terms of the EEA and the associated Production Sharing Contract with the CDI government, control of Block CI-26, including the FPSO and other associated infrastructure will revert to the CDI government on expiry of the EEA.

The second licence, which was extended in 2025 from 2028 to 2038, is a 57.6% operated working interest in the Baobab field, located in Block CI-40, which is eight kilometers south of the Espoir facilities and located in water depths ranging from 1,000 to 1,400 meters. Production from the Baobab field commenced in 2005. Crude oil from the Baobab field is produced to a dedicated FPSO with the associated natural gas delivered onshore via a subsea pipeline. Production at Baobab was temporarily shut in on January 31, 2025, as planned, with the FPSO disconnected and towed to drydock for repairs to extend the life of the vessel. The FPSO will be returned to the field and reconnected, with production expected to resume in the second quarter of 2026. The Company plans to commence further development activity at Baobab in the third quarter of 2026 with a drill program which is scheduled to be completed in the third quarter of 2027.

South Africa

The Company holds a 20% non-operated working interest in Block 11B/12B (the "Block") off the southeast coast of South Africa. In 2024, the Company and two of its partners gave notice of withdrawal from the Block, effective upon grant of the production right and associated transfer of ownership to the remaining partner, currently anticipated in 2026.

Producing and Non-Producing Crude Oil and Natural Gas Wells

The following table summarizes the number of wells in which the Company has a working interest that were producing or mechanically capable of producing as of December 31, 2025.

Producing	Natural Gas Wells		Crude Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	34,260	29,887.3	10,777	10,045.3	45,037	39,932.6
British Columbia	1,823	1,682.0	125	116.0	1,948	1,798.0
Saskatchewan	9,136	8,373.4	1,877	1,057.8	11,013	9,431.2
Manitoba	—	—	136	117.2	136	117.2
Total Canada	45,219	39,942.7	12,915	11,336.3	58,134	51,279.0
North Sea UK Sector	—	—	23	23.0	23	23.0
Offshore Africa						
Côte d'Ivoire	—	—	13	7.6	13	7.6
Total Company	45,219	39,942.7	12,951	11,366.9	58,170	51,309.6

The following table summarizes the number of wells in which the Company has a working interest that were not producing or not mechanically capable of producing as of December 31, 2025.

Non-Producing	Natural Gas Wells		Crude Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	9,184	7,650.3	12,257	11,122.0	21,441	18,772.3
British Columbia	2,378	2,124.1	393	348.1	2,771	2,472.2
Saskatchewan	1,211	1,138.8	3,563	2,891.0	4,774	4,029.8
Manitoba	—	—	158	100.5	158	100.5
Northwest Territories	89	11.2	—	—	89	11.2
Total Canada	12,862	10,924.4	16,371	14,461.6	29,233	25,386.0
North Sea UK Sector	3	3.0	23	23.0	26	26.0
Offshore Africa						
Côte d'Ivoire	—	—	27	15.6	27	15.6
Total Company	12,865	10,927.4	16,421	14,500.2	29,286	25,427.6

Properties With No Attributed Reserves

The following table summarizes the Company's unproved property as of December 31, 2025.

Country (thousands of acres)	Gross	Net
Canada	24,791	20,616
US	1	1
North Sea UK Sector	85	83
Côte d'Ivoire	92	52
South Africa	2,933	587
Total Company	**27,902**	**21,338**

Where the Company holds interests in different formations under the same surface area pursuant to separate leases, the acreage for each lease is included in the gross and net amounts.

Canadian Natural has approximately 466 thousand net acres attributed to the North America properties which are currently expected to expire by December 31, 2026.

SIGNIFICANT FACTORS OR UNCERTAINTIES RELEVANT TO PROPERTIES WITH NO ATTRIBUTED RESERVES

The Company's unproved property holdings are diverse and located in the North America and International regions. The land assets range from discovery areas where tenure to the property is held indefinitely by hydrocarbon test results or production to exploration areas in the early stages of evaluation. The Company continually reviews the economic viability and ranking of these unproved properties on the basis of product pricing, capital availability and allocation and level of infrastructure development in any specific area. From this process, some properties are scheduled for economic development activities while others are temporarily held inactive, sold, swapped or allowed to expire and relinquished back to the mineral rights owner.

FORWARD CONTRACTS

In the ordinary course of business, the Company has a number of delivery commitments to provide crude oil and natural gas under existing contracts and agreements. The Company has sufficient crude oil and natural gas reserves to meet these commitments.

2025 COSTS INCURRED IN CRUDE OIL, NATURAL GAS AND NGLs ACTIVITIES

($ millions)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	3,534	—	—	3,534
Unproved	172	—	—	172
Exploration	36	—	(46)	(10)
Development	4,938	1,223	547	6,708
	8,680	1,223	501	10,404
Add: Net non-cash and other costs [(1)]	(2,684)	(1,207)	(34)	(3,925)
Costs incurred	5,996	16	467	6,479

(1) Non-cash and other costs are comprised primarily of the non-cash gain on remeasurement and gain on disposition related to the AOSP asset swap completed in the fourth quarter of 2025, changes in ARO, and other fair value adjustments.

Exploration and Development Activities

The following table summarizes the crude oil and natural gas drilling activities completed by the Company for the year ended December 31, 2025. Total success rate for 2025, excluding service and stratigraphic test wells, was 99%.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Canada – Exploration and Production				
Crude Oil	2	2.0	366	355.5
Natural Gas	—	—	99	78.1
Dry	1	1.0	1	1.0
Service	—	—	58	58.0
Stratigraphic	—	—	18	18.0
Total	3	3.0	542	510.6
Canada – Oil Sands Mining and Upgrading				
Service	—	—	7	6.9
Stratigraphic	—	—	439	416.1
Total	—	—	446	423.0
Total Canada	3	3.0	988	933.6
Total International	—	—	—	—
Company Total	3	3.0	988	933.6

2026 ACTIVITY

Safe, reliable, effective and efficient operations will continue to be a focus of the Company in 2026. In December 2025, the Company released its 2026 operating capital budget[(1)] of approximately $6,300 million. With this capital, the Company is targeting production growth in 2026, as it invests in short and medium-term production, while commencing front-end engineering and design ("FEED") on potential additional medium and long-term value creation opportunities. In addition, the Company targets approximately $125 million of capital related to carbon capture projects. The Company targets $993 million in abandonment expenditures for 2026. Subsequently on March 5, 2026, the Company utilized its capital flexibility in 2026 by reducing forecasted operating capital expenditures by approximately $310 million, which reflects continuous improvement and efficiency gains on the Company's development program and a deferral of FEED capital on the Company's Jackpine mine expansion opportunity at AOSP. Annual 2026 forecasted operating capital is targeted at $5,990 million and 2026 annual production guidance was increased to be between 1,615,000 BOE/d and 1,665,000 BOE/d. Annual budgets and forecasts are developed and scrutinized throughout the year and can be changed, if necessary, to respond to price volatility, changes in project returns and the balancing of project risks and time horizons. The 2026 updated forecast targets a balanced drilling program throughout the year and will maintain flexibility to manage effective capital allocation.

The 2026 capital budget and production targets constitute forward-looking information. Refer to the "Advisory" section of this AIF for further details on forward-looking information.

(1) The capital budget is based on net capital expenditures (Non-GAAP Financial Measure) and excludes net acquisition costs. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's annual MD&A for the year ended December 31, 2025, dated March 4, 2026 for more details on net capital expenditures.

PRODUCTION ESTIMATES

The following table summarizes the estimated 2026 company gross proved and probable daily production included in the estimates of proved reserves and probable reserves as of December 31, 2025 using forecast prices and costs.

	Light and Medium Crude Oil (bbl/d)	Primary Heavy Crude Oil (bbl/d)	Pelican Lake Heavy Crude Oil (bbl/d)	Thermal Bitumen (bbl/d)	Mining Bitumen (bbl/d)	Synthetic Crude Oil (bbl/d)	Natural Gas (MMcf/d)	Natural Gas Liquids (bbl/d)	Barrels of Oil Equivalent (BOE/d)
Total Proved									
North America	58,870	91,262	42,548	268,876	64,000	495,825	2,255	107,723	1,504,943
Offshore Africa	7,867						6		8,851
Total Company	66,737	91,262	42,548	268,876	64,000	495,825	2,261	107,723	1,513,794
Total Probable									
North America	10,268	7,564	1,662	—	3,000	24,840	299	18,107	115,315
Offshore Africa	93						—		164
Total Company	10,362	7,564	1,662	—	3,000	24,840	300	18,107	115,479

Production History and Netbacks

	2025				
	Q1	Q2	Q3	Q4	Year Ended
North America Production and Netbacks by Product [1]					
Light and Medium Crude Oil [2]					
Average daily production (before royalties) (bbl/d)	48,257	49,010	70,341	71,555	59,883
Average daily sales volumes (before royalties) (bbl/d)	50,143	48,869	70,363	71,974	60,424
Netbacks ($/bbl)					
Sales price [3]	$ 101.64	$ 85.10	$ 84.96	$ 73.79	$ 85.05
Transportation [4]	13.53	10.74	6.38	5.59	8.49
Royalties [5]	14.37	11.88	12.86	10.75	12.34
Production expenses [6]	21.65	19.33	19.96	18.36	19.70
Netback	**$ 52.09**	**$ 43.15**	**$ 45.76**	**$ 39.09**	**$ 44.52**
Primary Heavy Crude Oil [2]					
Average daily production (before royalties) (bbl/d)	85,604	87,288	87,705	90,900	87,888
Average daily sales volumes (before royalties) (bbl/d)	83,479	88,959	87,319	91,568	87,852
Netbacks ($/bbl)					
Sales price [3]	$ 81.76	$ 72.88	$ 75.55	$ 65.69	$ 73.74
Transportation [4]	5.00	6.46	5.16	5.25	5.47
Royalties [5]	14.36	9.98	12.70	11.40	12.06
Production expenses [6]	18.13	17.44	16.46	14.87	16.68
Netback	**$ 44.27**	**$ 39.00**	**$ 41.23**	**$ 34.17**	**$ 39.53**
Pelican Lake Heavy Crude Oil [2]					
Average daily production (before royalties) (bbl/d)	43,175	43,078	42,070	41,577	42,470
Average daily sales volumes (before royalties) (bbl/d)	43,221	43,236	41,906	41,667	42,502
Netbacks ($/bbl)					
Sales price [3]	$ 83.57	$ 73.94	$ 75.94	$ 66.75	$ 75.07
Transportation [4]	4.21	5.42	4.62	4.30	4.64
Royalties [5]	21.25	14.19	17.62	16.14	17.29
Production expenses [6]	9.77	9.01	9.00	9.17	9.24
Netback	**$ 48.34**	**$ 45.32**	**$ 44.70**	**$ 37.14**	**$ 43.90**
Thermal Bitumen [2]					
Average daily production (before royalties) (bbl/d)	284,706	274,789	274,752	266,308	275,086
Average daily sales volumes (before royalties) (bbl/d)	285,844	278,538	267,744	269,778	275,410
Netbacks ($/bbl)					
Sales price [3]	$ 77.96	$ 70.13	$ 74.83	$ 66.61	$ 72.42
Transportation [4]	7.82	9.68	9.57	11.26	9.57
Royalties [5]	17.24	9.59	16.01	11.14	13.50
Production expenses [6]	11.23	11.05	10.35	11.72	11.09
Netback	**$ 41.67**	**$ 39.81**	**$ 38.90**	**$ 32.49**	**$ 38.26**
Natural Gas					
Average daily production (before royalties) (MMcf/d) [7]	2,436	2,398	2,658	2,657	2,538
Netbacks ($/Mcf)					
Sales price [3]	$ 3.06	$ 2.54	$ 1.45	$ 2.89	$ 2.47
Transportation [4]	0.62	0.60	0.56	0.57	0.59
Royalties [5]	0.11	0.08	0.02	0.09	0.08
Production expenses [6]	1.16	1.07	1.14	1.09	1.11
Netback	**$ 1.17**	**$ 0.79**	**$ (0.27)**	**$ 1.14**	**$ 0.69**
Natural Gas Liquids [2]					
Average daily production (before royalties) (bbl/d)	99,496	91,646	109,757	115,157	104,074
Average daily sales volumes (before royalties) (bbl/d)	99,496	91,646	109,757	115,157	104,074
Netbacks ($/bbl)					
Sales price [3]	$ 63.78	$ 52.68	$ 54.32	$ 48.55	$ 54.58
Transportation [4]	2.41	2.30	3.31	1.59	2.40
Royalties [5]	6.40	4.18	5.32	1.85	4.35
Production expenses [6]	8.87	6.47	8.40	8.64	8.15
Netback	**$ 46.10**	**$ 39.73**	**$ 37.29**	**$ 36.47**	**$ 39.68**

		2025				
		Q1	Q2	Q3	Q4	Year Ended
North Sea Production and Netbacks by Product [1]						
Light and Medium Crude Oil						
Average daily production (before royalties) (bbl/d)		11,507	7,761	7,045	7,618	8,468
Average daily sales volumes (before royalties) (bbl/d)		15,665	6,778	3,455	10,804	9,146
Netbacks ($/bbl)						
Sales price [3]	$	107.57 $	90.63 $	90.19 $	89.02 $	97.26
Transportation [4]		1.30	4.99	4.69	3.79	3.04
Royalties [5]		0.14	0.17	0.35	0.09	0.15
Production expenses [6]		117.56	186.50	188.98	115.45	136.47
Netback	**$**	**(11.43) $**	**(101.03) $**	**(103.83) $**	**(30.31) $**	**(42.40)**
Natural Gas						
Average daily production (before royalties) (MMcf/d) [7]		4	3	2	3	3
Netbacks ($/Mcf)						
Sales price [3]	$	16.43 $	10.00 $	8.57 $	8.87 $	11.77
Transportation [4]		2.40	(8.09)	1.15	1.59	(0.49)
Royalties [5]		—	—	—	—	—
Production expenses [6]		10.52	12.78	15.64	11.69	12.18
Netback	**$**	**3.51 $**	**5.31 $**	**(8.22) $**	**(4.41) $**	**0.08**
Offshore Africa Production and Netbacks by Product [1]						
Light and Medium Crude Oil						
Average daily production (before royalties) (bbl/d)		5,943	1,769	2,798	2,348	3,204
Average daily sales volumes (before royalties) (bbl/d)		11,048	500	2,313	4,318	4,520
Netbacks ($/bbl)						
Sales price [3]	$	106.30 $	95.92 $	99.90 $	83.53 $	99.71
Transportation [4]		—	—	—	—	—
Royalties [5]		4.61	4.19	4.60	3.84	4.41
Production expenses [6]		28.26	29.38	52.17	50.50	36.73
Netback	**$**	**73.43 $**	**62.35 $**	**43.13 $**	**29.19 $**	**58.57**
Natural Gas						
Average daily production (before royalties) (MMcf/d) [7]		11	6	8	0	6
Netbacks ($/Mcf)						
Sales price [3]	$	13.65 $	12.47 $	11.87 $	— $	12.77
Transportation [4]		0.13	0.21	0.15	—	0.18
Royalties [5]		0.63	0.57	0.55	—	0.59
Production expenses [6]		6.42	11.94	6.32	—	7.80
Netback	**$**	**6.47 $**	**(0.25) $**	**4.85 $**	**— $**	**4.20**
Total Exploration and Production						
Barrels of Oil Equivalent (BOE) [8]						
Average daily production (before royalties) (BOE/d)		987,232	956,550	1,039,125	1,038,780	1,005,655
Average daily sales volumes (before royalties) (BOE/d)		997,439	959,735	1,027,514	1,048,583	1,008,510
Netbacks ($/BOE) [1]						
Sales price [3]	$	54.95 $	47.17 $	45.31 $	44.85 $	47.98
Transportation [4]		5.34	5.94	5.38	5.56	5.54
Royalties [5]		8.76	5.58	7.53	5.73	6.90
Production expenses [6]		12.23	10.95	10.50	11.08	11.18
Netback	**$**	**28.62 $**	**24.70 $**	**21.90 $**	**22.48 $**	**24.36**

	2025				
	Q1	Q2	Q3	Q4	Year Ended
Oil Sands Mining and Upgrading Production and Netback [1]					
SCO (excluding Mining Bitumen) [9]					
Average daily production (before royalties) (bbl/d)	595,116	463,808	581,136	574,600	553,684
Average daily sales volumes (before royalties) (bbl/d)	602,048	463,586	579,209	578,824	555,917
Netbacks ($/bbl)					
Sales price [3] [10]	$ 95.52	$ 87.22	$ 87.85	$ 77.68	$ 87.10
Transportation [4]	3.21	3.73	3.86	2.74	3.37
Royalties [5] [11]	18.22	11.59	15.80	9.27	13.86
Production expenses [6]	21.88	26.53	21.29	22.15	22.76
Netback	**$ 52.21**	**$ 45.37**	**$ 46.90**	**$ 43.53**	**$ 47.11**
Mining Bitumen[12]					
Average daily production (before royalties) (bbl/d)				45,301	11,418
Average daily sales volumes (before royalties) (bbl/d)				45,301	11,418
Netbacks ($/bbl)					
Sales price [3] [10]			$	53.16	$ 53.16
Transportation [4]				0.28	0.28
Royalties [5] [11]				13.00	13.00
Production expenses [6]				17.95	17.95
Netback			**$**	**21.93**	**$ 21.93**

Notes to Production History and Netback Tables

(1) Netback is a non-GAAP financial measure that represents the net cash flows provided from core activities after the impact of all costs associated with bringing a product to market, on a per unit basis. The Company considers netback a key measure in evaluating its performance as it demonstrates the efficiency and profitability of the Company's activities. The netback calculations include the non-GAAP financial measures: realized price and transportation. Refer to the discussion of netbacks in the "Non-GAAP and Other Financial Measures" section of the Company's annual MD&A for the year ended December 31, 2025, dated March 4, 2026, for additional non-GAAP disclosure.

(2) Component of North America Exploration and Production crude oil and NGLs production and sales.

(3) Calculated as product sales, less blending expenses, divided by respective sales volumes.

(4) Calculated as transportation expense divided by respective sales volumes.

(5) Calculated as royalties divided by respective sales volumes.

(6) Calculated as production expense divided by respective sales volumes.

(7) Natural gas production volumes approximate sales volumes.

(8) Barrels of oil equivalent production and sales include total Exploration and Production crude oil, NGLs, and natural gas sales.

(9) Excludes mined diesel produced and consumed at Horizon as well as Mining Bitumen at AOSP.

(10) SCO and Mined Bitumen sales price is net of feedstock and blending costs.

(11) Royalty expense in the Oil Sands Mining and Upgrading segment is calculated based on bitumen royalties expensed during the period.

(12) Reflects the closing of the AOSP asset swap effective November 1, 2025, which resulted in the Company producing and reporting Mining Bitumen.

Selected Financial Information

($ millions, except per common share amounts)		2025	2024
Product sales [1]		**$ 44,167**	$ 41,509
Crude oil and NGLs		**$ 40,740**	$ 39,084
Natural gas		**$ 2,450**	$ 1,568
Net earnings		**$ 10,820**	$ 6,106
Per common share	– basic	**$ 5.17**	$ 2.87
	– diluted	**$ 5.16**	$ 2.85
Adjusted net earnings from operations [2]		**$ 7,444**	$ 7,414
Per common share	– basic [3]	**$ 3.56**	$ 3.49
	– diluted [3]	**$ 3.55**	$ 3.46
Cash flows from operating activities		**$ 15,106**	$ 13,386
Adjusted funds flow [2]		**$ 15,460**	$ 14,859
Per common share	– basic [3]	**$ 7.39**	$ 6.99
	– diluted [3]	**$ 7.37**	$ 6.94
Total assets		**$ 91,830**	$ 85,359
Long-term debt, net [4]		**$ 15,944**	$ 18,688
Cash flows used in investing activities		**$ 6,687**	$ 14,095
Net capital expenditures [2]		**$ 6,579**	$ 14,431
Abandonment expenditures		**$ 771**	$ 646

Notes to Selected Financial Information

(1) Further details related to product sales are disclosed in note 21 to the Company's audited consolidated financial statements for the years ended December 31, 2025 and December 31, 2024, dated March 4, 2026.

(2) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's annual MD&A for the year ended December 31, 2025, dated March 4, 2026.

(3) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's annual MD&A for the year ended December 31, 2025, dated March 4, 2026.

(4) Capital management measure. Refer to note 15 to the Company's audited consolidated financial statements for the years ended December 31, 2025 and December 31, 2024, dated March 4, 2026.

Dividend History

On January 17, 2001, the Board of Directors approved a dividend policy for the payment of regular quarterly dividends. Dividends have been paid in January, April, July and October of each year since April 2001. The dividend policy of the Company undergoes a periodic review by the Board of Directors and is subject to change at any time depending upon the earnings of the Company, its financial requirements and other factors existing at the time.

The following table shows the aggregate amount of the cash dividends declared per common share of the Company in each of the last three years ended December 31.

	2025	2024	2023
Cash dividends declared per common share [(1)]	**$ 2.35**	$ 2.14	$ 1.85

(1) Common share, per common share and dividend amounts in this table and in the below description have been updated to reflect the two for one common share split. Further details are disclosed under "Description of Capital Structure - Common Shares" in this AIF. The 2024 dividend is rounded to the nearest cent.

On March 4, 2026, the Board of Directors increased the regular quarterly cash dividend declared per common share from $0.5875 to $0.625 beginning with the dividend payable on April 7, 2026.

On March 5, 2025, the Board of Directors increased the regular quarterly cash dividend declared per common share from $0.5625 to $0.5875 beginning with the dividend payable on April 4, 2025.

In 2024, the Board of Directors approved two increases in the regular quarterly cash dividend. The first increase was approved on February 28, 2024 and increased the regular quarterly cash dividend declared per common share from $0.50 to $0.525 beginning with the dividend payable on April 5, 2024. The second increase was approved on October 4, 2024 and increased the regular quarterly cash dividend declared per common share from $0.525 to $0.5625 beginning with the dividend payable on January 3, 2025.

In 2023, the Board of Directors approved two increases in the regular quarterly cash dividend. The first increase was approved on March 1, 2023 and increased the quarterly cash dividend declared per common share from $0.425 to $0.45, beginning with the dividend payable on April 5, 2023. The second increase was declared on November 1, 2023, and increased the regular quarterly cash dividend declared per common share to $0.50 beginning with the dividend payable on January 5, 2024.

Description of Capital Structure

COMMON SHARES

The Company is authorized to issue an unlimited number of common shares, without nominal or par value. Holders of common shares are entitled to one vote per share at a meeting of shareholders of Canadian Natural, to receive such dividends as declared by the Board of Directors on the common shares and to receive pro-rata the remaining property and assets of the Company upon its dissolution or winding-up, subject to any rights having priority over the common shares.

At the Company's Annual and Special Meeting held on May 2, 2024, shareholders passed a Special Resolution approving a two for one common share split effective for shareholders of record as of market close on June 3, 2024. On June 10, 2024, shareholders of record received one additional share for every one common share held, with common shares trading on a split-adjusted basis beginning June 11, 2024. Common share, per common share, dividend, and stock option amounts for periods prior to the two for one common share split have been updated to reflect the common share split.

PREFERRED SHARES

The Company has no preferred shares outstanding. The Company is authorized to issue an unlimited number of preferred shares issuable in one or more series. The directors of the Company are authorized to determine, before the issue thereof, the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attaching to the preferred shares of each series.

CREDIT RATINGS

The following information relating to the Company's credit ratings is provided as it relates to the Company's financing costs, liquidity and operations. Specifically, credit ratings affect the Company's ability to obtain short-term and long-term financing and the cost of such financing. A reduction in the current rating on the Company's debt by its rating agencies or a negative change to the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. In addition, changes to credit ratings may affect the Company's ability to, and the associated costs of, entering into ordinary course derivative or hedging transactions and entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

Credit ratings accorded to the Company's debt securities are not recommendations to purchase, hold or sell the debt securities inasmuch as such ratings do not comment on the current market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant, and if any such rating is so revised or withdrawn, the Company is under no obligation to update this AIF.

	Senior Unsecured Debt Securities	Short-Term	Outlook/Trend [1]
Moody's Investors Service, Inc. ("Moody's")	Baa1	P-2	Stable
Fitch Ratings, Inc. ("Fitch")	BBB+	F2	Stable
DBRS Limited ("DBRS") [2]	A (low)	R-1 (low)	Stable

(1) Moody's and Fitch assign a rating outlook to Canadian Natural and not to individual long-term debt instruments.

(2) On February 27, 2026, DBRS changed its trend from "Negative" to "Stable".

Credit ratings are intended to provide investors with an independent opinion of the Company's ability to meet its financial obligations as they come due.

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of Baa by Moody's is the fourth highest of nine categories and is assigned to obligations that are judged to be medium-grade and are subject to moderate credit risk. Such securities may possess certain speculative characteristics. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through Caa in its corporate bond rating system. 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 that the obligation ranks in the lower end of its generic rating category. A Moody's rating outlook is an opinion regarding the likely rating direction over the medium term. A "Negative", "Positive" or "Developing" outlook indicates a higher likelihood of a rating change over the medium term. A "Stable" outlook indicates a low likelihood of a rating change over the medium term. Moody's credit ratings on commercial paper are on a short-term debt rating scale that ranges from P-1 to NP, representing the range of such securities rated from highest to lowest quality. A rating of P-2 by Moody's is the second highest of four categories and indicates a strong ability to repay short-term obligations.

Fitch's long-term debt 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. The modifiers "+" or "-" may be appended to a rating for AA through CCC, indicating relative differences of probability of default or recovery for issuers within major rating categories. A rating of BBB is 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. A Fitch rating outlook falls into four categories: "Positive", "Negative", "Stable" or "Evolving". Rating outlooks reflect weakening, improving or evolving trends which have not yet brought the credit profile to a level sufficient to trigger a rating change, but which may do so over the next two years. A Positive Rating Outlook indicates an upward trend on the rating scale and a Negative Rating Outlook signals a negative trend on the rating scale. Positive or Negative outlooks do not imply that a rating change is inevitable. Similarly, ratings with Stable outlooks can be raised or lowered without prior revision of the outlook. A Stable Rating Outlook indicates a low likelihood of rating change over a one- to two-year period. Where the fundamental trend has strong, conflicting elements of both positive and negative, the rating outlook may be described as Evolving. 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 F2 for commercial paper is the second highest of seven rating categories for short-term debt issuers. An F2 rating indicates good intrinsic capacity for timely payment of financial commitments. Where a liquidity profile is particularly strong, a "+" is added to the assigned rating.

DBRS' long-term debt credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the DBRS rating system, debt securities rated A are the third highest of eight categories and are considered of good credit quality. The capacity for the payment of financial obligations is substantial, though may be vulnerable to future events and qualifying negative factors are considered manageable. All rating categories from AA to CCC also contain subcategories "(high)" and "(low)" which indicate the relative standing within such rating category. The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. The rating trend is DBRS' opinion regarding the outlook for the rating in question, with rating trends falling into one of three categories "Positive", "Stable", or "Negative". The rating trend indicates the direction in which DBRS considers the rating may move if present circumstances continue, or in certain cases, unless challenges are addressed. DBRS' commercial paper and short-term debt ratings are on a rating scale that ranges from R-1 (high) to D. A rating of R-1 (low) for commercial paper is the third highest of ten rating categories for short-term debt issuers. An R-1 (low) rating indicates good credit quality. The capacity for the payment of financial obligations as they fall due is substantial, though may be vulnerable to future events and qualifying negative factors are considered manageable. The R-1 and R-2 rating categories are further denoted by the subcategories (high), (middle), and (low).

The credit ratings accorded to the Company's debt securities and commercial paper by the rating agencies are not recommendations to purchase, hold or sell the debt securities or commercial paper inasmuch as such ratings do not comment as to current market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant, and if any such rating is so revised or withdrawn, the Company is under no obligation to update this AIF.

The Company has made payments to Moody's, Fitch and DBRS in connection with the assignment of ratings to our long-term and short-term debt and will make payments to Moody's, Fitch and DBRS in connection with the confirmation of such ratings from time to time. The Company has not made any other payments to the listed credit rating organizations in the last two years.

Market for Securities

The Company's common shares are listed and posted for trading on the TSX and the NYSE under the symbol CNQ. Set forth below is the trading activity of the Company's common shares on the TSX in 2025.

	2025 Monthly Historical Trading on TSX			
Month	**High**	**Low**	**Close**	**Volume**
January	$ 48.26	$ 43.36	$ 44.15	155,293,448
February	$ 45.11	$ 39.92	$ 40.85	172,805,797
March	$ 45.34	$ 37.11	$ 44.28	481,288,187
April	$ 45.06	$ 34.92	$ 39.56	258,024,068
May	$ 45.02	$ 38.58	$ 41.67	213,331,752
June	$ 46.92	$ 41.92	$ 42.80	536,623,370
July	$ 44.43	$ 41.75	$ 43.86	231,603,230
August	$ 44.11	$ 40.62	$ 43.49	248,028,515
September	$ 46.12	$ 41.75	$ 44.50	518,396,076
October	$ 46.41	$ 41.67	$ 44.87	251,458,097
November	$ 49.20	$ 43.54	$ 47.29	239,493,334
December	$ 48.92	$ 43.00	$ 46.49	540,014,248

On March 5, 2025, the Board of Directors passed a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of a Normal Course Issuer Bid ("NCIB"), up to 178,738,237 common shares, being 10.0% of the public float (as determined in accordance with the rules of the TSX) as at February 28, 2025 (the "2025 NCIB").

For the year ended December 31, 2025, the Company purchased 33,480,000 common shares at a weighted average price of $43.28 per common share, which includes share repurchases for the period January 1, 2025 through March 12, 2025 that were executed under its prior NCIB, which expired on March 12, 2025. Subsequent to year-end, up to and including March 12, 2026, the Company purchased 3,825,500 shares under the 2025 NCIB at a weighted average price of $52.72 per common share.

On March 4, 2026, the Board of Directors passed a resolution authorizin g the Company to file a Notice of Intention with the TSX to purchase up to 182,396,564 common shares (being 10.0% of the Company's public float as at February 27, 2026 as determined in accordance with the rules of the TSX) by way of NCIB commencing on March 13, 2026 and expiring on March 12, 2027. Any purchases will be made through the facilities of the TSX, alternative Canadian trading platforms, and the NYSE, subject to applicable securities laws.

Directors and Executive Officers

The names, municipalities of residence, offices held with the Company and principal occupations of the Directors and Executive Officers of the Company for the five preceding years, are set forth below. Further detail on the Directors and Named Executive Officers and new Director nominees are found in the Company's Information Circular dated March 18, 2026 incorporated herein by reference.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Catherine M. Best, F.C.P.A., ICD.D Calgary, Alberta Canada	Director [(1)(2)] (age 72)	Corporate director. She has served continuously as a director of the Company since November 2003 and is also currently serving on the board of Superior Plus Corporation and is a member of the board of The Wawanesa Mutual Insurance Company and the Calgary Stampede Foundation.
Shelley A.M. Brown, C.M., F.C.P.A., F.C.A., ICD.D. Saskatoon, Saskatchewan Canada	Director [(1)] (age 69)	Corporate director. She was appointed to the Board of Directors of the Company in November 2025 and also currently serves on the board of directors of Stantec Inc. and InterPipeline Ltd. and was Chair of the Board of Governors for the University of Saskatchewan until 2025. She also serves on the board of various non-profit organizations. Ms. Brown served on the board of directors of Sherritt International Corporation until December 2025.
M. Elizabeth Cannon, Ph.D., O.C. Calgary, Alberta Canada	Director [(3)(5)] (age 63)	Corporate director. She is currently President emerita at the University of Calgary, having previously served at the University of Calgary as Dean of the Schulich School of Engineering from 2006-2010, and then as President and Vice Chancellor from 2010-2018. She was appointed as a director of the Company on November 5, 2019. She is also currently a board member of Mancal Corporation, and various non-profit organizations.
N. Murray Edwards, C.M. St. Moritz, Switzerland	Executive Chair and Director (age 66)	Corporate director and investor. He has served continuously as a director of the Company since September 1988. Currently, he is Chairman and serving on the board of directors of Ensign Energy Services Inc. and Magellan Aerospace Corporation.
Christopher L. Fong Calgary, Alberta Canada	Director [(3)(5)] (age 76)	Corporate director. He has served continuously as a director of the Company since November 2010.
Ambassador Gordon D. Giffin Sarasota, Florida U.S.A.	Director [(1)(4)] (age 76)	Partner and Global Vice Chair emeritus, Dentons US LLP (law firm). He has served continuously as a director of the Company since May 2002. He is also currently serving on the board of CIBC Bank USA and the board of trustees of the Carter Presidential Center.
Wilfred A. Gobert Calgary, Alberta Canada	Director [(1)(2)(4)] (age 78)	Independent businessman. He has served continuously as a director since November 2010. He is also currently serving on the board of directors of Paramount Resources Ltd.
Christine M. Healy Montreal, Quebec Canada	Director [(1)(4)] (age 54)	Corporate director, CEO and President of Northland Power Inc. since February 5, 2025. Prior thereto, President, AMEA (Asia, Middle East and Australia) of AtkinsRealis, a globally-leading design, engineering and project-management company, from 2023. Prior thereto, Senior Vice-President, Carbon Neutrality and Continental Europe for TotalEnergies from 2021 to 2023. She was appointed as a director of the Company effective February 27, 2024.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Steve W. Laut Calgary, Alberta Canada	Director [3][5] (age 68)	Corporate director. He has served continuously as a director of the Company since August 2006.
Honourable Frank J. McKenna P.C., O.C., O.N.B., K.C. Cap Pelé, New Brunswick Canada	Director [2][4] (age 78)	Deputy Chair, TD Bank Group (bank). He has served continuously as a director of the Company since August 2006. He also currently serves on the board of directors of Brookfield Asset Management Inc.
David A. Tuer Calgary, Alberta Canada	Director [1][5] (age 76)	Corporate director. Prior thereto, Chairman, Optiom Inc. (private insurance company) since 2015. He has served continuously as a director of the Company since May 2002.
Scott G. Stauth Calgary, Alberta Canada	President and Director[3][6] (age 60)	Officer of the Company. He was appointed to the Board of Directors on February 27, 2024.
Annette M. Verschuren, O.C. Toronto, Ontario Canada	Director [2][3] (age 69)	Chair and Chief Executive Officer of NRStor Inc., an energy storage project developer of energy storage technologies. She has served as a director of the Corporation continuously since November 2014. She currently is Chancellor Emeritus of Cape Breton University, a director of Liberty Mutual Insurance Group, and a board member of various non-profit organizations. She also currently serves on the board of directors of Air Canada and Saputo Inc. and is Chair of the Board of MaRs Discovery District.
Troy J.P. Andersen Calgary, Alberta Canada	Senior Vice-President, Canadian Conventional Field Operations (age 47)	Officer of the Company.
Brenda G. Balog Calgary, Alberta Canada	Vice-President, Legal and General Counsel (age 57)	Officer of the Company since April 2023. Prior thereto, Manager, Legal, Corporate Operations since 2011.
Calvin J. Bast Calgary, Alberta Canada	Senior Vice-President, Production (age 51)	Officer of the Company.
Victor C. Darel Calgary, Alberta Canada	Chief Financial Officer[6] (age 44)	Officer of the Company since May 2021. Prior thereto, Controller, Corporate Reporting from 2019 to 2021, Vice-President, Finance and Principal Accounting Officer from May 2021 to May 2023, and most recently Senior Vice-President Finance, and Principal Accounting Officer from June 2023 to April 2025.
Jay E. Froc Calgary, Alberta Canada	Chief Operating Officer, Oil Sands (age 60)	Officer of the Company.
Dwayne F. Giggs Calgary, Alberta Canada	Senior Vice-President, Exploration (age 49)	Officer of the Company since April 2021. Prior thereto, Exploration Manager from January 2017 to April 2021, and most recently Vice President - Exploration West from April 2021 to November 2021.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Dean W. Halewich Calgary, Alberta Canada	Senior Vice-President, Safety, Risk Management and Innovation (age 58)	Officer of the Company.
Sheryl L. Kapeluck Calgary, Alberta Canada	Senior Vice-President, Finance (age 50)	Officer of the Company since June 2023. Prior thereto, Director of Tax from 2019 to June 2023, and Vice-President, Finance, Corporate from July 2023 to April 2025.
Ronald K. Laing Calgary, Alberta Canada	Chief Commercial & Corporate Development Officer (age 56)	Officer of the Company.
Devin C. Lowe Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 52)	Officer of the Company.
Erin L. Lunn Calgary, Alberta Canada	Vice-President, Land (age 51)	Officer of the Company since February 2022. Prior thereto Land Manager, Negotiations from July 2016 to February 2022.
Mark A. Overwater Calgary, Alberta Canada	Vice-President, Marketing (age 58)	Officer of the Company since February 2023. Prior thereto Director, Crude Oil Marketing since May 2017.
Kyle G. Pisio Calgary, Alberta Canada	Vice-President, Drilling, Completions and Asset Retirement (age 44)	Officer of the Company since June 2021. Prior thereto Manager, Completions Engineering from July 2016 to June 2021.
Warren P. Raczynski Calgary, Alberta Canada	Senior Vice-President, Thermal (age 53)	Officer of the Company.
Kara L. Slemko Calgary, Alberta Canada	Senior Vice-President, Commercial Operations and Corporate Development (age 56)	Officer of the Company.
Trevor T. Wagil Sturgeon County, Alberta Canada	Senior Vice-President, Oil Sands Mining (age 41)	Officer of the Company.
Robin S. Zabek Calgary, Alberta Canada	Chief Operating Officer, Exploration and Production (age 54)	Officer of the Company.

(1) Member of the Audit Committee.

(2) Member of the Compensation Committee.

(3) Member of the Health, Safety, Asset Integrity and Environmental Committee.

(4) Member of the Nominating, Governance and Risk Committee.

(5) Member of the Reserves Committee.

(6) Mr. Darel was appointed Chief Financial Officer effective April 30, 2025.

All directors stand for election at each Annual Meeting of the Company's Shareholders. All of the current directors, with the exception of Ms. S.A.M. Brown, were elected to the Board at the last Annual and Special Meeting of the Company's Shareholders held on May 8, 2025. Ms. C.M. Best will be retiring in 2026 as she will not be standing for re-election at the Annual Meeting of the Company's Shareholders to be held on May 7, 2026. Subject to her re-election, Ms. S.A.M. Brown will be appointed as the new Chair of the Audit Committee after the next Annual Meeting. In addition, Mr. W.A. Gobert has reached the mandatory age of retirement and will also not be standing for re-election. The Honourable F.J. McKenna also reached the

Board's mandatory age of retirement in 2026. However, due to the significant changes to the Compensation Committee resulting from the retirements of Ms. Best and Mr. Gobert, both of whom were members of the Compensation Committee, the Board, in recognition of Mr. McKenna's unique skills and expertise, has requested that Mr. McKenna extend his tenure on the Board for at least one additional year to support the new Compensation Committee members and ensure that the role of Chair of the Compensation Committee is properly transitioned to his successor.

As of the date hereof, 11 of the 13 directors are independent. The two management directors are Mr. N.M. Edwards and Mr. S.G. Stauth. At the 2026 Annual Meeting of the Company's Shareholders, 12 directors will be standing for election, 10 of whom will be independent. For details on the Director nominees, refer to the Company's Information Circular dated March 18, 2026 incorporated herein by reference.

As at December 31, 2025, the directors and executive officers of the Company, as a group, beneficially owned or controlled or directed, directly or indirectly, in the aggregate, approximately 47 million common shares (approximately 2%) of the total outstanding common shares of 2,081,578,000 (approximately 3% after the exercise of options held by them pursuant to the Company's stock option plan).

There are potential conflicts of interest to which the directors and officers of the Company may become subject in connection with the operations of the Company. Some of the directors and officers have been and will continue to be engaged in the identification and evaluation of businesses and assets with a view to potential acquisition of interests on their own behalf and on behalf of other corporations. Situations may arise where the directors and officers will be in direct competition with the Company. Conflicts, if any, will be subject to the procedures and remedies under the Business Corporations Act (Alberta).

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

From time to time, the Company is the subject of litigation arising out of the Company's normal course of operations. Damages claimed under such litigation may be material and the outcome of such litigation may materially impact the Company's financial condition or results of operations. While the Company assesses the merits of each lawsuit and defends itself accordingly, the Company may be required to incur significant expenses or devote significant resources to defend itself in such litigation. There are currently no legal proceedings to which the Company is or was a party, or that any of its property is or was the subject of, which would be expected to have a material impact on the Company's financial condition and the Company is not aware of any such legal proceedings that are contemplated.

During the year ended December 31, 2025, there were no penalties or sanctions imposed against the Company by a court of competent jurisdiction or other regulatory body relating to securities legislation or by a securities regulatory authority and the Company has not entered into any settlement agreements before a court of competent jurisdiction or other regulatory body relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

TRANSFER AGENTS AND REGISTRAR

The Company's transfer agent and registrar for its common shares is Computershare Trust Company of Canada in the cities of Calgary and Toronto and Computershare Investor Services LLC in the city of New York. The registers for transfers of the Company's common shares are maintained by Computershare Trust Company of Canada.

MATERIAL CONTRACTS

During the most recently completed financial year, the Company 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.

INTERESTS OF EXPERTS

The Company's independent registered public accounting firm is PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have issued a Report of Independent Registered Public Accounting Firm dated March 4, 2026 in respect of the Company's consolidated financial statements as at December 31, 2025 and December 31, 2024 and for each of the three years in the period ended December 31, 2025 and on the effectiveness of internal control over financial reporting as at December 31, 2025. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada, including the Rules of Professional Conduct with Guidance - Chartered Professional Accountants of Alberta and any applicable legislation or regulations, as well as the rules of the US Securities and Exchange Commission and the Public Company Accounting Oversight Board on auditor independence.

Based on information provided by the relevant persons or companies, there are beneficial interests, direct or indirect, in less than 1% of the Company's securities or property or securities or property of our associates or affiliates held by Sproule International Limited or GLJ Ltd., or any partners, employees or consultants of such independent reserves evaluators who participated in and who were in a position to directly influence the preparation of the relevant report, or any such person who, at the time of the preparation of the report was in a position to directly influence the outcome of the preparation of the report.

AUDIT COMMITTEE INFORMATION

Audit Committee Members

The Audit Committee of the Board of Directors is comprised of Ms. C.M. Best, Chair, Messrs. G.D. Giffin, W.A. Gobert and D.A. Tuer, Ms. C.M. Healy and Ms. S.A.M. Brown, each of whom is independent and financially literate as those terms are defined under Canadian securities regulations, National Instrument 52-110 and the NYSE listing standards as they pertain to audit committees of listed issuers. The education and experience of each member of the Audit Committee relevant to their responsibilities as an Audit Committee member is described below.

Ms. C.M. Best is a chartered accountant with over 20 years' experience as a staff member and partner of an international public accounting firm. During her tenure, she was responsible for direct oversight and supervision of a large staff of auditors conducting audits of the financial reporting of significant publicly traded entities, many of which were oil and gas companies. This oversight and supervision required Ms. Best to maintain a current understanding of generally accepted accounting principles, and be able to assess their application in each of her clients. It also required an understanding of internal controls and financial reporting processes and procedures. Ms. Best, who is chair of the Audit Committee, qualifies as an "audit committee financial expert" under the rules issued by the SEC pursuant to the requirements of the Sarbanes-Oxley Act of 2002. Ms. Best will be retiring in 2026 as she will not be standing for re-election to the Board of Directors.

Ambassador G.D. Giffin's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from a law practice of over thirty years, involving complex accounting and audit-related issues associated with complicated commercial transactions and disputes. He has developed extensive practical experience and an understanding of internal controls and procedures for financial reporting from his service on audit committees for several publicly traded issuers and the continued pursuit of extensive professional reading and study on related subjects.

Mr. W.A. Gobert holds an MBA (Finance) degree from McMaster University as well as a Bachelor of Science (Honours) degree from the University of Windsor and holds a Chartered Financial Analyst (CFA) designation. Mr. Gobert was Vice Chair of Peters & Co. Limited, an independent, fully integrated investment dealer specializing in providing comprehensive investment research, and acting as an active underwriter and financial advisor specializing in the Canadian energy sector. During his 27 year career with Peters & Co. Limited, Mr. Gobert developed expertise in connection with the review, analysis and evaluation of financial statements that presented a variety of complex accounting issues and subsequently supervised and oversaw individuals directly engaged in the review, analysis and evaluation of similarly complex financial disclosure. As a result, Mr. Gobert developed an understanding of generally accepted accounting principles, financial statements, internal controls and financial reporting. Mr. Gobert qualifies as an "audit committee financial expert" under the rules issued by the SEC pursuant to the requirements of the Sarbanes-Oxley Act of 2002. Mr. Gobert has reached the mandatory age of retirement and will not be standing for re-election to the Board of Directors.

Mr. D.A. Tuer's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from professional training and a business career as a chief executive officer in a large publicly traded company which provided experience in analyzing and evaluating financial statements and supervising persons engaged in the preparation, analysis and evaluation of financial statements of publicly traded companies. He has gained an understanding of internal controls and procedures for financial reporting through oversight of those functions, and the understanding of audit committee functions through his years of chief executive involvement.

Ms. C.M. Healy holds a B.A. (Hon.), Economics from Memorial University and a Juris Doctor from Osgoode Hall Law School. Ms. Healy's education and experience relevant to the performance of her responsibilities as an audit committee member is derived from her professional training and a 26 year legal/business career in the energy industry in both the public and private sector, which involved complex accounting and audit-related issues associated with strategic development of business assets, portfolio management, mergers and acquisitions and complex commercial issues and transactions associated with resource management and development both domestically and internationally. She gained an understanding of audit committee functions and internal controls for financial reporting through her executive oversight of those functions in various chief executive and senior management roles. Ms. Healy was also Vice Chair of the Board and Chair of the Audit and Risk Committee for Lester B. Pearson United World College of the Pacific. Ms. Healy will be stepping down from the Audit Committee after the Annual Meeting of Shareholders on May 7, 2026.

Ms. S.A.M. Brown is a chartered professional accountant with over 40 years' accounting experience, having served as Director for Audit Services and Regional Managing Partner and Senior Audit Partner of an international public accounting firm. During her tenure, she was responsible for direct oversight and supervision of a large staff of auditors conducting audits of the financial reporting of publicly-traded entities, many of which were mining and oil and natural gas companies. This oversight and supervision required Ms. Brown to maintain a current understanding of generally accepted accounting principles, and be able to assess their application in each of her clients. It also required an understanding of internal controls and financial reporting processes and procedures. Ms. Brown is, or has served as, audit committee chair for four other publicly-traded companies. Ms. Brown qualifies as an "audit committee financial expert" under the rules issued by the SEC pursuant to the requirements of the Sarbanes-Oxley Act of 2002. Subject to election, Ms. Brown will replace Ms. Best as the Chair of the Audit Committee after the Annual Meeting of Shareholders on May 7, 2026.

Dr. G.E. Isaac, a director nominee at the Annual Meeting of Shareholders to be held on May 7, 2026, will, subject to election as a director, be appointed to the Audit Committee. Dr. Grant Isaac has been the President and Chief Operating Officer of Cameco Corporation since 2025. Prior to that he held various officer roles including as Chief Financial Officer of Cameco for 14 years. During his tenure as CFO, Dr. Isaac was responsible for direct oversight and supervision of complex financial transactions and disclosure, preparation of financial statements, internal controls and financial reporting. He is currently responsible for executive oversight of Cameco's commercial, operational and financial strategy. In addition to his extensive business and financial experience, he has held numerous academic positions in Business, Economics and International Trade. Dr. Isaac received a Bachelors of Arts (Economics) and a Masters of Arts (Economics) from the University of Saskatchewan and a Ph.D from the London School of Economics. Dr. Isaac qualifies as an "audit committee financial expert" under the rules issued by the SEC pursuant to the requirements of the Sarbanes-Oxley Act of 2002.

Auditor Service Fees

The Audit Committee of the Board of Directors in 2025 approved specified audit and non-audit services to be performed by PricewaterhouseCoopers LLP ("PwC"). The services provided include: (i) the annual audit of the Company's consolidated financial statements and internal controls over financial reporting, reviews of the Company's quarterly unaudited consolidated financial statements, audits of certain of the Company's subsidiary companies' annual financial statements as well as other audit services provided in connection with statutory and regulatory filings as set out in "Audit fees" in the table below; (ii) audit related services including Crown Royalty Statements, and pension reporting as set out in "Audit related fees" below; (iii) tax services related to corporate tax return matters as set out in "Tax fees" in the table below; and (iv) non-audit services related to French translation services and accessing resource materials through PwC's accounting literature library as set out in "All other fees" in the table below.

Auditor service (000's)	**2025**	2024
Audit fees	**$ 2,702**	$ 2,557
Audit related fees	**490**	1,284
Tax fees	**421**	413
All other fees	**107**	63
Total	**$ 3,720**	$ 4,317

The Charter of the Audit Committee of the Company is attached as Schedule “C” to this AIF.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on the SEDAR+ website at www.sedarplus.ca and on EDGAR at www.sec.gov.

Additional information including Directors' and Executive Officers' remuneration and indebtedness, Director nominees standing for re-election, principal holders of the Company's securities, options to purchase the Company's securities and the interest of insiders in material transactions is contained in the Company's Notice of Annual Meeting and Information Circular dated March 18, 2026 in connection with the Annual Meeting of Shareholders of Canadian Natural to be held on May 7, 2026 which information is incorporated herein by reference. Additional financial information and discussion of the affairs of the Company and the business environment in which the Company operates is provided in the Company's MD&A, comparative Consolidated Financial Statements and Supplementary Oil & Gas Information for the most recently completed fiscal year ended December 31, 2025 respectively, as set forth in the 2025 Annual Report to the Shareholders, which information is incorporated herein by reference.

For additional copies of this AIF, please contact prior to June 2026:

Corporate Secretary of the Corporation at:
2100, 855 - 2nd Street S.W.
Calgary, Alberta T2P 4J8

And from June 2026 onward, please contact:

Corporate Secretary of the Corporation at:
400 - 4th Avenue S.W.
Calgary, Alberta T2P 0J4

SCHEDULE "A"

FORM 51-101F2

REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Report on Reserves Data

To the Board of Directors of Canadian Natural Resources Limited (the "Company"):

1. We have evaluated and reviewed the Company's North America, United Kingdom and Offshore Africa petroleum and natural gas reserves data as at December 31, 2025. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2025, 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 and review.
3. We carried out our evaluation and review 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 and review to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation and review 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 total 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 and reviewed for the year ended December 31, 2025, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation/Review 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
Sproule International Limited	December 31, 2025	Canada and USA	—	84,843	6,301	91,145
Sproule International Limited	December 31, 2025	United Kingdom and Offshore Africa	—	1,473	—	1,473
Total			—	86,316	6,301	92,618

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 as of December 31, 2025.
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 reports referred to above:

Sproule International Limited
Calgary, Alberta, Canada,

Original Signed by Gary R. Finnis, P. Eng.
Gary R. Finnis, P.Eng.
Principal Reservoir Engineer
Date: March 4, 2026
APEGA ID 62965

Sproule International Limited
Calgary, Alberta, Canada,

Original Signed by Ilia Chaikine, P. Eng.
Ilia Chaikine, P.Eng.
Senior Reservoir Engineer
DATE: March 4, 2026
APEGA ID 138300

Original Signed by Alexey Romanov, Ph.D., P.Geo
Alexey Romanov, Ph.D., P.Geo
Principal Geoscientist
Date: March 4, 2026
APEGA ID 112313

Sproule International Limited
APEGA Permit #06151

Original Signed by Steven Golko, P.Eng.
Steven Golko, P.Eng.
Senior Vice President, Reserves & Resources
Date: March 4, 2026
RM APEGA ID 80169

Sproule International Limited
APEGA Permit #06151

Original Signed By Meghan Klein, P.Eng.
Meghan Klein, P.Eng.
Head of Reservoir Engineering, Americas
Date: March 4, 2026
RM APEGA ID 84981

FORM 51-101F2

REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Report on Reserves Data

To the Board of Directors of Canadian Natural Resources Limited (the "Company"):

1. We have evaluated the Company's Canadian Oil Sands Mining and Upgrading reserves data as at December 31, 2025. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2025, 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 total 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, 2025, 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 or Auditor	Effective Date of Evaluation/Review 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, 2025	Canada	—	98,394	—	98,394
Total			**—**	**98,394**	**—**	**98,394**

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 4, 2026

Original Signed By

SIGNED "TRACY K. BELLINGHAM"

Tracy K. Bellingham, P.Eng.
Executive Vice President & COO

SCHEDULE “B”

FORM 51-101F3

REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

Report of Management and Directors on Reserves Data and Other Information

Management of Canadian Natural Resources Limited (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 and reviewed the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves 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 Reserves 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 Reserves 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.

Original Signed By

SIGNED "SCOTT G. STAUTH"
Scott G. Stauth
President

Original Signed By

SIGNED "VICTOR C. DAREL"
Victor C. Darel
Chief Financial Officer

Original Signed By

SIGNED "DAVID A. TUER"
David A. Tuer
Independent Director and Chair of the Reserves Committee

Original Signed By

SIGNED "CATHERINE M. BEST"
Catherine M. Best
Independent Director and Chair of the Audit Committee

Dated this 4th day of March, 2026

SCHEDULE “C”

CANADIAN NATURAL RESOURCES LIMITED
(the “Corporation”)
Charter of the Audit Committee

I Audit Committee Purpose

The Audit Committee is appointed by the Board of Directors (the "Board") to assist the Board in fulfilling its responsibility for the stewardship of the Corporation in overseeing the business and affairs of the Corporation. Although the Audit Committee has the powers and responsibilities set forth in this Charter, the role of the Audit Committee is oversight. The Audit Committee's primary duties and responsibilities are to:

1. ensure that the Corporation's management implements and maintains an effective system of internal controls over financial reporting;
2. monitor and oversee the integrity of the Corporation's financial statements, financial reporting processes and systems of internal controls regarding financial, accounting and compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material facts;
3. consider and recommend to the Board, jointly with the Health, Safety, Asset Integrity and Environmental Committee, the accounting firm to be retained by the Corporation to complete an independent assurance review of the Corporation's GHG emissions reporting and establish the fees and other compensation to be paid in respect thereof;
4. select and recommend for appointment by the shareholders, the Corporation's independent auditors, pre-approve all audit and non-audit services to be provided to the Corporation by the Corporation's independent auditors consistent with all applicable laws, and establish the fees and other compensation to be paid to the independent auditors;
5. monitor the independence, qualifications and performance of the Corporation's independent auditors and oversee the audit and review of the Corporation's financial statements;
6. monitor the performance of the Corporation's internal audit function, internal control of financial reporting programs, Sarbanes-Oxley Compliance program as well as the cybersecurity measures implemented in response to the Corporation's assessment of cyber risk, including risks related to the use of artificial intelligence;
7. establish procedures for the receipt, retention, response to and treatment of complaints, including confidential, anonymous submissions by the Corporation's employees, regarding accounting, internal controls or auditing matters; and
8. provide an avenue of communication among the independent auditors, management, the internal auditing function and the Board.

II Audit Committee Composition, Procedures and Organization

1. The Audit Committee shall consist of at least three (3) directors as determined by the Board, each of whom shall be independent, non-executive directors, free from any relationship that would interfere with the exercise of his or her independent judgment. Audit Committee members shall meet the independence and experience requirements of the regulatory bodies to which the Corporation is subject to. All members of the Audit Committee shall have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements at the time of their appointment to the Audit Committee. At least one member of the Audit Committee shall have accounting or related financial management expertise and qualify as a "financial expert" or similar designation in accordance with the requirements of the regulatory bodies to which the Corporation may be subject to.
2. The Board at its organizational meeting held in conjunction with each annual general meeting of the shareholders shall appoint the members of the Audit Committee for the ensuing year. The Board may at any time remove or replace any member of the Audit Committee and may fill any vacancy in the Audit Committee.
3. The Board shall appoint a member of the Audit Committee as chair of the Audit Committee. If an Audit Committee Chair is not designated by the Board, or is not present at a meeting of the Audit Committee, the members of the Audit Committee may designate a chair by majority vote of the Audit Committee membership.
4. The Secretary or the Assistant Secretary of the Corporation shall be secretary of the Audit Committee unless the Audit Committee appoints a secretary of the Audit Committee.
5. The quorum for meetings shall be one half (or where one half of the members of the Audit Committee is not a whole number, the whole number which is closest to and less than one half) of the members of the Audit Committee subject to a minimum of two members of the Audit Committee present in person or by telephone or other telecommunications device that permits all persons participating in the meeting to speak and to hear each other.
6. Meetings of the Audit Committee shall be conducted as follows:
    (a) the Audit Committee shall meet at least four (4) times annually at such times and at such locations as may be requested by the Chair of the Audit Committee;

(b) the Audit Committee shall meet privately in executive sessions at each meeting with management, the manager of internal auditing, the independent auditors, and as a committee to discuss any matters that the Audit Committee or each of these groups believe should be discussed.

7. The independent auditors and internal auditors shall have a direct line of communication to the Audit Committee through its chair and may bypass management if deemed necessary. Any employee may bring before the Audit Committee directly and may bypass management if deemed necessary any matter involving questionable, illegal or improper financial practices or transactions.

III Audit Committee Duties and Responsibilities

1. The overall duties and responsibilities of the Audit Committee shall be as follows:
   (a) to assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and its approval of the Corporation's annual and quarterly consolidated financial statements;
   (b) to establish and maintain a direct line of communication with the Corporation's internal auditors and independent auditors and assess their performance;
   (c) to ensure that the management of the Corporation has implemented and is maintaining an effective system of internal controls over financial reporting;
   (d) to report regularly to the Board on the fulfillment of its duties and responsibilities; and,
   (e) to review annually the Audit Committee Charter and recommend any changes to the Nominating, Governance and Risk Committee for approval by the Board.
2. The duties and responsibilities of the Audit Committee as they relate to the independent auditors shall be as follows:
   (a) to select and recommend to the Board of Directors for appointment by the shareholders, the Corporation's independent auditors, review the independence and monitor the performance of the independent auditors and approve any discharge of auditors when circumstances warrant;
   (b) to approve the fees and other significant compensation to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors;
   (c) to review and discuss with management and the independent auditors prior to the annual audit the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department and oversee the audit of the Corporation's financial statements;
   (d) to pre-approve all proposed non-audit services to be provided by the independent auditors except those non-audit services prohibited by legislation;
   (e) on an annual basis, obtain and review a report by the independent auditors describing (i) the independent auditor's internal quality control procedures; (ii) any material issues raised by the most recent quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the firm; and, (iii) any steps taken to address any such issues arising from the review, inquiry or investigation, and, receive a written statement from the independent auditors outlining all significant relationships they have with the Corporation that could impair the auditor's independence. The Corporation's independent auditors may not be engaged to perform prohibited activities under the Sarbanes-Oxley Act of 2002, the rules of the Public Company Accounting Oversight Board, or any other regulatory body which the Corporation is governed by;
   (f) to review and discuss with the independent auditors, upon completion of their audit and prior to the filing or releasing annual financial statements:
      (i) contents of their report, including:
         A. all critical accounting policies and practices used;
         B. all alternative treatments of financial information within GAAP that have been discussed with management, ramifications of the use of such treatments and the treatment preferred by the independent auditor;
         C. other material written communications between the independent auditor and management;
      (ii) scope and quality of the audit work performed;
      (iii) adequacy of the Corporation's financial and auditing personnel;
      (iv) cooperation received from the Corporation's personnel during the audit;
      (v) internal resources used;
      (vi) significant transactions outside of the normal business of the Corporation;

(vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems;

(viii) the non-audit services provided by the independent auditors; and,

(ix) consider the independent auditor's judgments about the quality and appropriateness of the Corporation's accounting principles and critical accounting estimates as applied in its financial reporting.

(g) to review and approve a report to shareholders as required, to be included in the Corporation's Information Circular and Proxy Statement, disclosing any non-audit services approved by the Audit Committee.

(h) to review and approve the Corporation's hiring policies regarding current or former partners and employees of the present and former independent auditors of the Corporation.

3. The duties and responsibilities of the Audit Committee as they relate to the internal auditors shall be as follows:

(a) to review the budget, internal audit function with respect to the organization structure, staffing, effectiveness and qualifications of the Corporation's internal audit department;

(b) to review the internal audit plan; and

(c) to review significant internal audit findings and recommendations together with management's response and follow-up thereto.

4. The duties and responsibilities of the Audit Committee as they relate to the internal control procedures of the Corporation shall be as follows:

(a) to review the appropriateness and effectiveness of the Corporation's policies and business practices which impact the financial integrity of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems, use of artificial intelligence, financial controls, management reporting (including financial reporting) and the management of risks related thereto;

(b) to review any unresolved issues between management and the independent auditors that could affect the financial reporting or internal controls of the Corporation; and

(c) to periodically review the extent to which recommendations made by the internal audit staff or by the independent auditors have been implemented.

5. Other duties and responsibilities of the Audit Committee shall be as follows:

(a) to review and discuss with management, the internal audit group and the independent auditors, the Corporation's unaudited quarterly consolidated financial statements and related Management Discussion & Analysis including the impact of unusual items and changes in accounting principles and estimates, the earnings press releases before disclosure to the public and report to the Board with respect thereto;

(b) to review and discuss with management, the internal audit group and the independent auditors, the Corporation's audited annual consolidated financial statements and related Management Discussion & Analysis including the impact of unusual items and changes in accounting principles and estimates, the earnings press releases before disclosure to the public and report to the Board with respect thereto;

(c) to ensure adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements, other than the quarterly and annual earnings press releases, and periodically assess the adequacy of those procedures;

(d) to review management's report on the appropriateness of the policies and procedures used in the preparation of the Corporation's consolidated financial statements and other required disclosure documents and consider recommendations for any material change to such policies;

(e) to review with management, the independent auditors and legal counsel, if necessary, any litigation, claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the consolidated financial statements;

(f) to review and consider management's assessment and report on the Corporation's cyber risk, including risks associated with the use of artificial intelligence and the measures implemented by the Corporation in response to those risks;

(g) to establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

(h) to co-ordinate meetings with the Reserves Committee of the Corporation, the Corporation's senior engineering management, independent evaluating engineers and auditors as required and consider such further inquiries as are necessary to approve the consolidated financial statements;

(i) to develop a calendar of activities to be undertaken by the Audit Committee for each ensuing year and to submit the calendar in the appropriate format to the Board following each annual meeting of shareholders;

(j) to perform any other activities consistent with this Charter, the Corporation's By-laws and governing law, as the Audit Committee or the Board deems necessary or appropriate;

(k) to maintain minutes of meetings, and to regularly report to the Board on any significant results of the foregoing activities; and

(l) review, evaluate, approve, ratify, modify, disapprove and monitor jointly with the Nominating, Governance and Risk Committee any Related Party Transaction involving the Corporation and any of the following four categories (A) director, (B) executive officer, (C) person or entity that beneficially owns 5% or more of the Company's voting securities, or (D) any immediate family member of any of the foregoing (each, a "Related Party"), to determine whether (a) the terms are fair and reasonable, on an arms' length basis and otherwise in the best interest of the Corporation; and (b) the transaction is otherwise in accordance with applicable securities laws and the listing requirements of any applicable stock exchanges. "Related Party Transaction" means any transaction, arrangement, or relationship (or series of related transactions) in which:

(i) the Corporation or any subsidiary is a participant;

(ii) the amount involved exceeds the threshold that triggers disclosure as prescribed by applicable securities legislation or the listing standards of any applicable stock exchange; and

(iii) a Related Party has, or will have, a direct or indirect material interest, as determined with reference to applicable securities laws and the requirements of any applicable stock exchange.

The Audit Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to the independent auditors as well as officers and employees of the Corporation. The Audit Committee has the authority to retain, at the Corporation's expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties. The Corporation shall at all times make adequate provisions for the payment of all fees and other compensation approved by the Audit Committee, to the Corporation's independent auditors in connection with the issuance of its audit report, or to any consultants or experts employed by the Audit Committee.



CANADIAN NATURAL RESOURCES LIMITED

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2025 AND 2024

March 4, 2026

Consolidated Financial Statements

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Management's Report

The accompanying consolidated financial statements of Canadian Natural Resources Limited (the "Company") and all other information contained elsewhere in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards") as appropriate in the circumstances. The financial information presented elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized and recorded, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to audit and provide their independent audit opinions on the following:

- the Company's consolidated financial statements as at and for the year ended December 31, 2025; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2025.

Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board, which is comprised entirely of independent directors. The Audit Committee meets with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

SIGNED "SCOTT G. STAUTH"	SIGNED "VICTOR C. DAREL"
SCOTT G. STAUTH	**VICTOR C. DAREL, CPA**
President	Chief Financial Officer

Calgary, Alberta, Canada
March 4, 2026

Management's Assessment of Internal Control over Financial Reporting

Management of Canadian Natural Resources Limited (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rules 13a-15(f) and 15d-15(f) under the United States Securities Exchange Act of 1934, as amended.

Management, including the Company's President and the Company's Chief Financial Officer, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on the assessment, management has concluded that the Company's internal control over financial reporting was effective as at December 31, 2025. Management recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2025, as stated in their accompanying Report of Independent Registered Public Accounting Firm.

SIGNED "SCOTT G. STAUTH"

SCOTT G. STAUTH
President

SIGNED "VICTOR C. DAREL"

VICTOR C. DAREL, CPA
Chief Financial Officer

Calgary, Alberta, Canada
March 4, 2026

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Canadian Natural Resources Limited

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Canadian Natural Resources Limited and its subsidiaries (the "Company") as of December 31, 2025 and 2024, and the related consolidated statements of earnings, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

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, 2025 and 2024, and its financial performance and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards"). Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework (2013) issued by the COSO.

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 Assessment of Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and 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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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 (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) 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.

Determination of the fair value of the interests in the Athabasca Oil Sands Project ("AOSP") Mines in the AOSP Asset Swap Transaction

As described in Notes 1, 3 and 6 to the Company's consolidated financial statements, on November 1, 2025, the Company completed the AOSP asset swap transaction. The AOSP assets include the AOSP mines, the Scotford Upgrader ("Scotford") and the Quest Carbon Capture and Storage facility ("Quest"), all of which are presented as property, plant and equipment. As a result of the transaction, the Company acquired the remaining 10% interest in the AOSP mines and associated reserves, resulting in the Company owning a 100% interest in such assets. The transaction was accounted for as a business combination achieved in stages using the acquisition method of accounting as a result of obtaining control of the AOSP mines. The Company was deemed to have disposed of its pre-existing interests in the AOSP mines and re-acquired them at fair value, as determined in accordance with IFRS Accounting Standards, at the acquisition date, with any gains on remeasurement recognized in net earnings. Management determined the acquisition date fair value of the 100% interest in the AOSP mines, using an estimated 18% discount rate based on comparable market transactions, was $15,488 million, and recognized a $4,508 million non-cash gain on the remeasurement of its pre-existing interests in the AOSP mines as a result. Management determined the fair value of the interests in the AOSP mines by using a discounted estimate of future cash flows approach which required the use of estimates and judgments by management, including developing key assumptions related to discount rate, estimated future prices, expected future rates of production, quantity of reserves, production expense, capital expenditures, and allocation of fair value between the AOSP mines, Scotford and Quest. Management utilizes third party specialists, specifically independent qualified reserves evaluators ("Management's Specialists") to evaluate its estimated quantity of reserves.

The principal considerations for our determination that performing procedures relating to the determination of the fair value of the interests in the AOSP mines in the AOSP Asset Swap Transaction is a critical audit matter are the significant judgments required by management, including the use of Management's Specialists, when determining the fair value of the interests in the AOSP mines. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures and evaluating evidence obtained related to the key assumptions used in developing the fair value, at the acquisition date, of the interests in the AOSP mines, including discount rate, estimated future prices, expected future rates of production, quantity of reserves, production expense, capital expenditures, and allocation of fair value between the AOSP mines, Scotford and Quest. The audit effort also involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's determination of the fair value, at the acquisition date, of the interests in the AOSP mines. These procedures also included, among others, testing management's process for determining the fair value, at the acquisition date, of the interests in the AOSP mines, including (i) evaluating the appropriateness of the method used by management in making the estimate, (ii) testing the completeness and accuracy of underlying data used in management's determination of the fair value, and (iii) evaluating the reasonableness of key assumptions used by management related to discount rate, estimated future prices, expected future rates of production, quantity of reserves, production expense, capital expenditures, and allocation of fair value between the AOSP mines, Scotford and Quest. Evaluating the key assumptions related to estimated future prices, expected future rates of production, production expense, capital expenditures, and allocation of fair value between the AOSP mines, Scotford and Quest involved assessing whether they were reasonable considering the past performance of the AOSP mines, external market and industry data and whether they were consistent with evidence obtained in other areas of the audit, as applicable. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of the present value of estimated future cash flows from the AOSP mines and the reasonableness of the discount rate. The work of Management's Specialists was used in performing procedures to evaluate the reasonableness of the estimated quantity of reserves. As a basis for using this work, Management's Specialists' qualifications were understood and the Company's relationship with Management's Specialists was assessed. The procedures performed also included evaluating the methods and assumptions used by Management's Specialists, testing the completeness and accuracy of the data used by Management's Specialists, and evaluating Management's Specialists' findings. Professionals with specialized skill and knowledge assisted in this evaluation, as applicable.

The Impact of Crude Oil and Natural Gas Reserves on Property, Plant and Equipment Assets in the North America Exploration and Production Segment

As described in Notes 1, 3 and 6 to the Company's consolidated financial statements, the property, plant and equipment ("PP&E") balance in the North America Exploration and Production segment was $27.0 billion as of December 31, 2025. Depletion, depreciation and amortization ("DD&A") expense for the North America Exploration and Production segment was $4.5 billion for the year ended December 31, 2025. In accordance with the Company's accounting policies, crude oil and natural gas properties in the North America Exploration and Production segment, excluding certain major components, are depleted

using the unit-of-production method based on proved reserves. Estimates of the Company's crude oil and natural gas reserves are based on estimated future prices and production costs, expected future rates of production and the timing and amount of future development expenditures. Management utilizes third party specialists, specifically independent qualified reserve evaluators, to evaluate its estimates of crude oil and natural gas reserves. These estimates are utilized for the calculation of DD&A expense.

The principal considerations for our determination that performing procedures relating to the impact of crude oil and natural gas reserves on PP&E assets in the North America Exploration and Production segment is a critical audit matter are the significant judgments required by management, including the use of Management's Specialists, when developing the estimates, specifically related to the estimates of crude oil and natural gas reserves in the North America Exploration and Production segment. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures and evaluating evidence obtained related to the assumptions used in developing the estimates, including estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of internal controls in the North America Exploration and Production segment relating to management's estimates of the Company's crude oil and natural gas reserves and the calculation of DD&A expense. The work of Management's Specialists was used in performing the procedures to evaluate the reasonableness of the estimates of crude oil and natural gas reserves used to determine DD&A expense for the North America Exploration and Production segment. As a basis for using this work, Management's Specialists' qualifications were understood, and the Company's relationship with Management's Specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by Management's Specialists, tests of data used by Management's Specialists and an evaluation of Management's Specialists' findings. Professionals with specialized skill and knowledge assisted in this evaluation, as applicable. The procedures performed also included, among others, evaluating whether the assumptions used by Management's Specialists related to estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures were reasonable considering the current and past performance of the Company, consistency with industry pricing forecasts, and whether they were consistent with evidence obtained in other areas of the audit, as applicable. Additionally, these procedures also included testing the unit-of-production rates used to calculate DD&A expense.

/s/ PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada

March 4, 2026

We have served as the Company's auditor since 1973.

Consolidated Balance Sheets

As at December 31, (millions of Canadian dollars)	Note	2025	2024
ASSETS			
Current assets			
Cash and cash equivalents		**$ 673**	$ 131
Accounts receivable		**3,999**	4,126
Inventory	4	**2,621**	2,793
Prepaids and other		**301**	279
Current portion of other long-term assets	9	**70**	76
		7,664	7,405
Exploration and evaluation assets	5	**2,651**	2,526
Property, plant and equipment	6	**77,645**	73,414
Lease assets	7	**3,001**	1,394
Other long-term assets	9	**869**	620
		$ 91,830	$ 85,359
LIABILITIES			
Current liabilities			
Accounts payable		**$ 1,105**	$ 1,079
Accrued liabilities		**4,255**	4,525
Current income taxes payable		**597**	92
Current portion of long-term debt	10	**441**	2,400
Current portion of other long-term liabilities	11	**1,665**	1,535
		8,063	9,631
Long-term debt	10	**16,176**	16,419
Other long-term liabilities	11	**11,936**	9,302
Deferred income taxes	12	**11,289**	10,539
		47,464	45,891
SHAREHOLDERS' EQUITY			
Share capital	13	**11,421**	11,064
Retained earnings		**32,726**	28,103
Accumulated other comprehensive income	14	**219**	301
		44,366	39,468
		$ 91,830	$ 85,359

Commitments and contingencies (note 19)

Approved by the Board of Directors on March 4, 2026.

SIGNED "CATHERINE M. BEST"	SIGNED "N. MURRAY EDWARDS"
CATHERINE M. BEST	**N. MURRAY EDWARDS**
Chair of the Audit Committee and Director	Executive Chairman of the Board of Directors and Director

Consolidated Statements of Earnings

For the years ended December 31, (millions of Canadian dollars, except per common share amounts)	Note	2025	2024	2023
Product sales	21	**$ 44,167**	$ 41,509	$ 40,835
Less: royalties		**(5,405)**	(5,853)	(4,867)
Revenue		**38,762**	35,656	35,968
Expenses				
Production		**9,155**	8,093	8,480
Blending and feedstock [1]		**8,071**	7,931	7,732
Transportation [1]		**2,751**	2,053	1,570
Depletion, depreciation and amortization [2]	5,6,7	**9,384**	6,681	6,413
Administration		**615**	503	452
Share-based compensation	11	**180**	279	491
Asset retirement obligation accretion	11	**380**	389	366
Interest and other financing expense	17	**834**	592	636
Risk management (gain) loss	18	**(18)**	177	(2)
Foreign exchange (gain) loss		**(762)**	955	(279)
Gain on acquisitions, disposition, and remeasurement	6	**(5,069)**	—	—
Gain from investment	8	**—**	(56)	(56)
		25,521	27,597	25,803
Earnings before taxes		**13,241**	8,059	10,165
Current income tax expense	12	**1,911**	1,531	1,879
Deferred income tax expense	12	**510**	422	53
Net earnings		**$ 10,820**	$ 6,106	$ 8,233
Net earnings per common share [3]				
Basic	16	**$ 5.17**	$ 2.87	$ 3.77
Diluted	16	**$ 5.16**	$ 2.85	$ 3.74

(1) During 2025, the Company revised its presentation of transportation, blending and feedstock costs, showing the expenses on a disaggregated basis. The comparative periods presented have been updated to reflect the revision (note 1).

(2) Depletion, depreciation and amortization expense for the year ended December 31, 2025 includes a $ 1,462 million (2024 – $ 160 million; 2023 – $ 436 million) non-cash recoverability charge for revisions to abandonment and decommissioning costs in the North Sea, a $269 million non-cash recoverability charge related to the decision to not pursue an extension of the Company's Production Sharing Contract ("PSC") for the Espoir field in Offshore Africa, and a $46 million non-cash derecognition of exploration and evaluation assets related to the decision to not pursue development of Kossipo in Offshore Africa (notes 5 and 6).

(3) Common share, per common share, dividend, and stock option amounts for 2023 have been updated to reflect the two for one common share split (note 1).

Consolidated Statements of Comprehensive Income

For the years ended December 31, (millions of Canadian dollars)		2025		2024		2023
Net earnings	**$**	**10,820**	$	6,106	$	8,233
Items that may be reclassified subsequently to net earnings						
Net change in derivative financial instruments designated as cash flow hedges						
Unrealized income, net of taxes of $2 million (2024 – $nil; 2023 – $nil)		**18**		2		2
Reclassification to net earnings, net of taxes of $2 million (2024 – $nil; 2023 – $nil)		**(22)**		(4)		(5)
		(4)		(2)		(3)
Foreign currency translation adjustment						
Translation of net investment		**(78)**		131		(34)
Other comprehensive (loss) income, net of taxes		**(82)**		129		(37)
Comprehensive income	**$**	**10,738**	$	6,235	$	8,196

Consolidated Statements of Changes in Equity

For the years ended December 31, (millions of Canadian dollars)	Note		2025		2024		2023
Share capital	13						
Balance – beginning of year		**$**	**11,064**	$	10,712	$	10,294
Issued upon exercise of stock options			**264**		280		372
Previously recognized liability on stock options exercised for common shares			**273**		358		435
Purchase of common shares under Normal Course Issuer Bid			**(180)**		(286)		(389)
Balance – end of year			**11,421**		11,064		10,712
Retained earnings							
Balance – beginning of year			**28,103**		28,948		27,672
Net earnings			**10,820**		6,106		8,233
Dividends on common shares	13		**(4,910)**		(4,537)		(4,028)
Purchase of common shares under Normal Course Issuer Bid, including tax	13		**(1,287)**		(2,414)		(2,929)
Balance – end of year			**32,726**		28,103		28,948
Accumulated other comprehensive income	14						
Balance – beginning of year			**301**		172		209
Other comprehensive (loss) income, net of taxes			**(82)**		129		(37)
Balance – end of year			**219**		301		172
Shareholders' equity		**$**	**44,366**	$	39,468	$	39,832

Consolidated Statements of Cash Flows

For the years ended December 31, (millions of Canadian dollars)	Note	2025	2024	2023
Operating activities				
Net earnings		**$ 10,820**	$ 6,106	$ 8,233
Non-cash items				
Depletion, depreciation and amortization	5,6,7	**9,384**	6,681	6,413
Share-based compensation		**180**	279	491
Asset retirement obligation accretion		**380**	389	366
Unrealized risk management loss		**71**	9	12
Unrealized foreign exchange (gain) loss		**(870)**	888	(260)
Gain on acquisitions, disposition, and remeasurement	6	**(5,069)**	—	—
Gain from investment	8	**—**	(50)	(34)
Deferred income tax expense		**510**	422	53
Realized foreign exchange on financing activities [(1)]		**54**	135	—
Abandonment expenditures	11	**(771)**	(646)	(509)
Other		**(255)**	(84)	5
Net change in non-cash working capital	20	**672**	(743)	(2,417)
Cash flows from operating activities		**15,106**	13,386	12,353
Financing activities				
(Repayment) issuance of bank credit facilities and commercial paper, net	10,20	**(1,395)**	5,466	—
Issuance of other long-term debt	10,20	**1,634**	2,639	—
Repayment of other long-term debt	10,20	**(1,699)**	(1,008)	(416)
Payment of lease liabilities	7,20	**(361)**	(325)	(285)
Issuance of common shares on exercise of stock options	13	**264**	280	372
Dividends on common shares		**(4,871)**	(4,429)	(3,891)
Purchase of common shares under Normal Course Issuer Bid	13	**(1,449)**	(2,660)	(3,318)
Cash flows used in financing activities		**(7,877)**	(37)	(7,538)
Investing activities				
Net expenditures on exploration and evaluation assets	5,21	**(115)**	(92)	(44)
Net expenditures on property, plant and equipment	6,21	**(6,676)**	(5,291)	(4,865)
Cash from AOSP asset swap	6	**212**	—	—
Acquisition of Chevron's assets	5,6,21	**—**	(9,163)	—
Net proceeds from investment	8	**—**	575	—
Net change in non-cash working capital	20	**(108)**	(124)	51
Cash flows used in investing activities		**(6,687)**	(14,095)	(4,858)
Increase (decrease) in cash and cash equivalents		**542**	(746)	(43)
Cash and cash equivalents – beginning of year		**131**	877	920
Cash and cash equivalents – end of year		**$ 673**	$ 131	$ 877
Interest paid on long-term debt		**$ 978**	$ 586	$ 602
Income taxes paid, net		**$ 1,722**	$ 1,144	$ 3,317

(1) Realized foreign exchange on financing activities primarily relates to the repayment of US dollar denominated debt.

Notes to the Consolidated Financial Statements

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

1. Accounting Policies

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire in Offshore Africa.

The Oil Sands Mining and Upgrading segment produces synthetic crude oil through bitumen mining and upgrading operations at Horizon Oil Sands ("Horizon") and through the Company's interest in the Athabasca Oil Sands Project ("AOSP").

Within Western Canada in the Midstream and Refining segment, the Company maintains certain activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("NWRP"), a general partnership formed to upgrade and refine bitumen in the Province of Alberta.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855 - 2 Street S.W., Calgary, Alberta, Canada.

The Company's consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards"). The accounting policies adopted by the Company under the IFRS Accounting Standards are set out below. The Company has consistently applied the same accounting policies throughout all periods presented, except where the IFRS Accounting Standards permit new accounting standards to be adopted prospectively.

During 2025, the Company revised its presentation of transportation expense and blending and feedstock costs, showing the expenses on a disaggregated basis in the consolidated statements of earnings. Previously, the Company aggregated transportation, blending and feedstock costs. The revision provides users with more information to evaluate the Company's performance. The consolidated financial statements and related notes have been updated for all periods presented.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost basis, unless otherwise required.

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships. Subsidiaries include all entities over which the Company has control. Subsidiaries are consolidated from the date on which the Company obtains control. They are deconsolidated from the date that control ceases.

Certain of the Company's activities are conducted through joint arrangements in which two or more parties have joint control. Where the Company has determined that it has a direct ownership interest in jointly controlled assets and obligations for the liabilities (a "joint operation"), the assets, liabilities, revenue, and expenses related to the joint operation are included in the consolidated financial statements in proportion to the Company's interest. Where the Company has determined that it has an interest in jointly controlled entities (a "joint venture"), it uses the equity method of accounting. Under the equity method, the Company's initial and subsequent investments are recognized at cost and subsequently adjusted for the Company's share of the joint venture's income or loss, less distributions received. If the Company's share of the joint venture's loss equals or exceeds its interest in the joint venture, the Company discontinues recognizing its share of further losses. The Company resumes recognizing profits when its share of profits exceeds the accumulated share of losses not recognized.

Joint ventures accounted for using the equity method of accounting are tested for impairment whenever objective evidence indicates that the carrying amount of the investment may not be recoverable. Indications of impairment include a history of losses, significant capital expenditure overruns, liquidity concerns, financial restructuring of the investee or significant adverse changes in the technological, economic, or legal environment. The amount of the impairment is measured as the difference between the carrying amount of the investment and the higher of its fair value less costs of disposal and its value in use. Impairment losses are reversed in subsequent periods if the amount of the loss decreases, and the decrease can be related objectively to an event occurring after the impairment was recognized.

(B) INVENTORY

Inventory is primarily comprised of product inventory, materials and supplies and other inventory, including emissions credits, and is carried at the lower of cost and net realizable value. Product inventory is comprised of crude oil held for sale, including pipeline linefill and crude oil stored in floating production, storage and offloading vessels ("FPSO"). Cost of product inventory consists of purchase costs, direct production costs, directly attributable overhead, and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value for product inventory is determined by reference to forward prices. Cost for materials and supplies consists of purchase costs and is based on a first-in, first-out or an average cost basis. Net realizable value for materials and supplies and other inventory, including emissions credits, is determined by reference to current market prices and regulated compliance rates. Emissions credit inventory generated in the normal course of business is initially measured in accordance with the Company's accounting policy for government grants.

(C) EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves.

E&E costs are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area. These costs are recognized in net earnings.

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. An E&E asset is derecognized upon disposal or when no future economic benefits are expected to arise from its use. Any gain or loss arising on derecognition of the asset is recognized in net earnings within depletion, depreciation and amortization.

E&E assets are also tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of the related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks.

(D) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and recoverability charges. Assets under construction are not depleted or depreciated until available for their intended use.

Exploration and Production

The cost of an asset comprises its acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

When significant components of an item of property, plant and equipment, including crude oil and natural gas interests, have different useful lives, they are accounted for separately.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves, except for certain major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

Oil Sands Mining and Upgrading

Capitalized costs for the Oil Sands Mining and Upgrading segment are reported separately from the Company's North America Exploration and Production segment. Capitalized costs include acquisition costs, construction and development costs, overburden removal costs incurred during the initial development of a mine at Horizon and AOSP, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset, with any gains or losses resulting from the difference in the re-measured fair value compared to the carrying value of the consideration recognized in net earnings.

Mine-related costs are depleted using the unit-of-production method based on proved reserves. Capitalized overburden removal costs are depleted over the life of the mining reserves that directly benefit from overburden removal activity. Costs of the upgraders and related infrastructure located on the Horizon and AOSP sites are depreciated on the unit-of-production method based on the estimated productive capacity of the respective upgraders and related infrastructure. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 20 years.

Midstream, Refining and Head Office

The Company capitalizes all costs that expand the capacity or extend the useful life of the midstream, refining and head office assets. Midstream and Refining assets are depreciated on a straight-line basis over their estimated useful lives ranging from 5 to 30 years. Head office assets are depreciated on a declining balance basis.

Useful lives

The depletion rates and expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in depletion rates and useful lives accounted for prospectively.

Derecognition

A property, plant and equipment asset is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is recognized in net earnings within depletion, depreciation and amortization.

Major maintenance expenditures

Inspection costs associated with major turnarounds are capitalized and depreciated over the period to the next major turnaround. Maintenance costs are expensed as incurred.

Impairment

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGUs, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and a recoverability charge is taken through depletion, depreciation and amortization expense.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized recoverability charges may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The revised recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, had no recoverability charge been recognized for the asset in prior periods. A reversal of a recoverability charge is recognized in net earnings. After a reversal, the depletion, depreciation and amortization charge is adjusted in future periods to allocate the asset's revised carrying amount over its remaining useful life.

(E) BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition. Any excess of the consideration paid over the fair value of the net assets acquired is recognized as an asset. Any excess of the fair value of the net assets acquired over the consideration paid is recognized in net earnings. For business combinations where the Company obtains control over an acquiree or acquiree's assets in which the Company has previously held interests, the acquisition is accounted for as a business combination achieved in stages. In these instances, the Company's previously held interests are re-measured to fair value as at the acquisition date with any gains or losses resulting from the difference in the fair value compared to the carrying value of the previously held interests recognized in net earnings.

(F) LEASES

The Company recognizes a lease asset and a lease liability at the commencement date of the lease contract. The lease asset is initially measured at cost. The cost of a lease asset includes the amount of the initial measurement of the lease liability, lease payments made prior to the commencement date, initial direct costs and estimates of the asset retirement obligation, if any. Subsequent to initial recognition, the lease asset is depreciated using the straight-line method over the earlier of the end of the useful life of the lease asset or the lease term.

Lease liabilities are initially measured at the present value of lease payments discounted at the rate implicit in the lease, or if not readily determinable, the Company's incremental borrowing rate. Lease liabilities are remeasured if there are changes in the lease term or if the Company changes its assessment of whether it is reasonably certain it will exercise a purchase, extension or termination option. Lease liabilities are also remeasured if there are changes in the estimate of the amounts payable under the lease due to changes in indices or rates, or residual value guarantees. The Company reassesses its lease commitments and existing contracts when events or changes in circumstances indicate changes in business activities or expected use of the underlying assets.

Lease assets are reported in a separate caption in the consolidated balance sheets. Lease liabilities are reported within other long-term liabilities in the consolidated balance sheets.

Where the Company acts as the operator of a joint operation, the Company recognizes 100% of the related lease asset and lease liability. As the Company recovers its joint operation partners' share of the costs of the lease contract, these recoveries are recognized as other income in the consolidated statements of earnings.

(G) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on all of its property, plant and equipment and certain exploration and evaluation assets based on current legislation and operating practices. Provisions for asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Provisions are measured at the present value of management's best estimate of expenditures required to settle the obligation as at the date of the balance sheets. Subsequent to the initial measurement, the obligation is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense, whereas changes due to discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

(H) FOREIGN CURRENCY TRANSLATION

Functional and presentation currency

Items included in the financial statements of the Company's subsidiary companies and partnerships are measured using the currency of the primary economic environment in which the subsidiary operates (the "functional currency").

When the Company disposes of its entire interest in a foreign operation, the foreign currency gains or losses accumulated in other comprehensive income related to the foreign operation are recognized in net earnings.

(I) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the sale of crude oil and natural gas liquids ("NGLs") and natural gas products is recognized when performance obligations in the sales contract are satisfied and it is probable that the Company will collect the consideration to which it is entitled. Performance obligations are generally satisfied at the point in time when the product is delivered to a location specified in a contract and control passes to the customer. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Contracts for sale of the Company's products generally have terms of less than a year, with certain contracts extending beyond one year. Contracts in North America generally specify delivery of crude oil and NGLs and natural gas throughout the term of the contract. Contracts in the North Sea and Offshore Africa generally specify delivery of crude oil at a point in time.

Sales of the Company's crude oil and NGLs and natural gas products to customers are made pursuant to contracts based on prevailing commodity pricing at or near the time of delivery and volumes of product delivered. Revenues are typically collected in the month following delivery and accordingly, the Company has elected to apply the practical expedient to not adjust consideration for the effects of a financing component. Purchases and sales of crude oil and NGLs and natural gas with the same counterparty, made to facilitate sales to customers or potential customers, that are entered into in contemplation of one another, are combined and recorded as non-monetary exchanges and measured at the net settlement amount.

Revenue in the consolidated statements of earnings represents the Company's share of product sales net of royalty payments to governments and other mineral interest owners. The Company discloses the disaggregation of revenues from sales of crude oil and NGLs and natural gas in the segmented information in note 21. Related costs of goods sold are comprised of production, transportation, blending and feedstock, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

(J) PRODUCTION SHARING CONTRACTS

Production generated from Côte d'Ivoire in Offshore Africa is shared under the terms of various Production Sharing Contracts ("PSCs"). Product sales are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective government state oil company (the "Government"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the respective PSCs.

(K) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases.

Deferred income tax assets and liabilities are calculated using the substantively enacted income tax rates that are expected to apply when the asset or liability is recovered. Deferred income tax assets or liabilities are not recognized when they arise on the initial recognition of an asset or liability in a transaction (other than in a business combination or a transaction that, on initial recognition, gives rise to equal taxable and deductible temporary differences) that, at the time of the transaction, affects neither accounting nor taxable profit. Deferred income tax assets or liabilities are also not recognized on possible future distributions of retained earnings of subsidiaries where the timing of the distribution can be controlled by the Company and it is probable that a distribution will not be made in the foreseeable future, or when distributions can be made without incurring income taxes.

Deferred income tax assets for deductible temporary differences and tax loss carryforwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized. The carrying amount of deferred income tax assets is reviewed at each reporting date and is reduced if it is no longer probable that sufficient future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized.

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date.

(L) SHARE-BASED COMPENSATION

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are remeasured each reporting period for subsequent changes in the fair value of the liability. Fair value is determined using the Black-Scholes valuation model under a graded vesting method. Expected volatility is estimated based on historic results. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by the employee and any previously recognized liability associated with the stock options are recorded as share capital.

The Performance Share Unit ("PSU") Plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met. PSUs vest three years from original grant date. The liability for PSUs is initially measured in reference to the Company's share price and the number of awards expected to vest and is remeasured at each reporting period for changes in the fair value of the liability.

(M) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: financial assets at amortized cost; financial liabilities at amortized cost; and fair value through profit or loss. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash and cash equivalents, accounts receivable and certain other long-term assets are classified as financial assets at amortized cost since it is the Company's intention to hold these assets to maturity and the related cash flows are solely comprised of payments of principal and interest. Investments in publicly traded shares are classified as fair value through profit or loss. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as financial liabilities at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

Financial assets and liabilities are also categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs in respect of financial instruments at fair value through profit or loss are recognized in net earnings. Transaction costs in respect of other financial instruments are included in the initial measurement of the financial instrument.

Impairment of financial assets

At each reporting date, on a forward-looking basis, the Company assesses the expected credit losses associated with its financial assets carried 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 receivable, the Company applies the simplified approach permitted by IFRS 9, which requires expected lifetime credit losses to be recognized from initial recognition of the receivables. To measure expected credit losses, accounts receivable are grouped based on the number of days the receivables have been outstanding and 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 12-month expected credit loss. Changes in the provision for expected credit loss are recognized in net earnings.

(N) RISK MANAGEMENT ACTIVITIES

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted forward commodity prices and volatility, interest rate yield curves, foreign exchange rates, and other volatility factors. The carrying amount of a risk management asset and liability is adjusted for the Company's own credit risk.

The Company documents all derivative financial instruments that are formally designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales and purchases of crude oil and natural gas in order to protect its cash flow for its capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in net earnings in the same period or periods in which the commodity is sold or purchased. The ineffective portion of changes in the fair value of these designated contracts is recognized in risk management activities in net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not closely related to the host contract, except when the host contract is an asset.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income and amortized into net earnings in the periods in which the underlying hedged items are recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized in net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in net earnings.

Foreign currency forward contracts are periodically used to manage foreign currency cash requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange gains and losses when the hedged item is recognized in net earnings. Changes in the fair value of non-designated foreign currency forward contracts are recognized in risk management activities in net earnings.

The Company periodically enters into foreign currency put option contracts to manage its exposure to foreign currency exchange rate risk. The Company periodically sells put option contracts which grant the purchaser the right, but not the obligation, to exercise the contract on the expiry date (European option) and are designated as derivatives held for trading. The amount that may be payable upon exercise is initially recognized as a liability valued at the amount paid by the counterparty. The option is remeasured to fair value at each reporting date with gains and losses recognized in risk management activities in net earnings. If the option expires unexercised, the remaining liability is derecognized.

(O) GOVERNMENT GRANTS

The Company receives or is eligible for government grants, including emissions credits. Government grants are recognized in net earnings when there is reasonable assurance that the Company will comply with the conditions attached to the grant and the grant will be received. Emissions performance and offset credits generated under the Alberta Technology Innovation and Emissions Reduction ("TIER") regulation are initially recorded at the value prescribed by the Alberta TIER fund compliance rates in effect at the time the credits are recognized.

(P) PER COMMON SHARE AMOUNTS

The Company calculates basic earnings per common share by dividing net earnings by the weighted average number of common shares outstanding during the period. As the Company's Option Plan allows for the settlement of stock options in either cash or shares at the option of the holder, diluted earnings per common share is calculated using the more dilutive of cash settlement or share settlement under the treasury stock method.

(Q) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are included in equity as a deduction from proceeds, net of tax. When the Company acquires its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value, including tax, is recognized as a reduction of retained earnings. Shares are cancelled upon purchase.

(R) COMMON SHARE SPLIT AND COMPARATIVE FIGURES

At the Company's Annual and Special Meeting held on May 2, 2024, shareholders passed a Special Resolution approving a two for one common share split effective for shareholders of record as of market close on June 3, 2024. On June 10, 2024, shareholders of record received one additional share for every one common share held, with common shares trading on a split-adjusted basis beginning June 11, 2024. Common share, per common share, dividend, and stock option amounts for periods prior to the two for one common share split have been updated to reflect the common share split.

2. Accounting Standards Issued But Not Yet Applied

In April 2024, the IASB issued IFRS 18 "Presentation and Disclosure in Financial Statements", which provides presentation and disclosure requirements for the primary financial statements and related notes, replacing IAS 1 "Presentation of Financial Statements". IFRS 18 introduces defined categories for income and expenses and requires disclosure of new defined subtotals, including operating profit. The new standard also requires additional notes for management-defined performance measures and disclosure of certain expenses by nature. There are some associated changes to the statement of cash flows, including the starting point for the calculation of cash flows from operating activities and the categorization of interest and dividends. IFRS 18 is effective January 1, 2027, with early adoption permitted. The new standard is required to be adopted retrospectively. The Company continues to assess the impact of IFRS 18 on the Company's consolidated financial statements.

In May 2024, the IASB issued amendments to IFRS 9 "Financial Instruments" and IFRS 7 "Financial Instruments: Disclosures" to clarify the date of recognition and derecognition of some financial assets and liabilities, with a new exception for some financial liabilities settled using an electronic payment system. The amendments also clarify the classification of certain financial assets, and add disclosure requirements for financial instruments with certain contingent features and for equity investments designated at fair value through other comprehensive income. The amendments are effective January 1, 2026, and are required to be adopted retrospectively with early adoption permitted. The Company will adopt the amendments retrospectively without restating comparative information, as the impact of applying these amendments is not expected to be material to the consolidated financial statements.

3. Critical Accounting Estimates and Judgements

The Company has made estimates, assumptions, and judgements regarding certain assets, liabilities, revenues, and expenses in the preparation of the consolidated financial statements, primarily related to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates, assumptions, and judgements that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

(A) CRUDE OIL AND NATURAL GAS RESERVES

Purchase price allocations, depletion, depreciation and amortization, asset retirement obligations, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserves estimates, evaluated by the Company's Independent Qualified Reserves Evaluators, are based on estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations, and judgements including the potential impact of climate related matters and in accordance with related government regulations. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information.

(B) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on its property, plant and equipment based on current legislation and operating practices. Estimated future costs include assumptions of dates of future abandonment, technological advances, and estimates of future inflation and discount rates. Actual costs may vary from the estimated provision due to changes in environmental legislation, the impact of inflation, changes in technology, changes in operating practices, revisions to work scope, changes in the date of abandonment due to changes in reserves life, and the potential impact of climate related matters and in accordance with related government regulations. These differences may have a material impact on the estimated provision.

(C) INCOME TAXES

The Company is subject to income taxes in numerous legal jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

(D) FAIR VALUE OF DERIVATIVES AND OTHER FINANCIAL INSTRUMENTS

The fair value of financial instruments that are not traded in an active market are determined using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted forward commodity prices and volatility, interest rate yield curves, discount rates, foreign exchange rates, and other volatility factors.

(E) PURCHASE PRICE ALLOCATIONS

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions, and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties, derived from the present value of estimated future cash flows from the assets, together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation and amortization expense and impairment tests.

(F) SHARE-BASED COMPENSATION

The Company has made various assumptions in estimating the fair values of stock options granted under its Option Plan including expected volatility, expected exercise timing, and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the estimated fair value of the liability.

(G) IDENTIFICATION OF CGUs

CGUs are defined as 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 classification of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, shared infrastructures, and the way in which management monitors the Company's operations.

(H) IMPAIRMENT OF ASSETS

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGUs' or the assets' fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available, including information on future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, after-tax discount rates (currently ranging from 10% to 12%), and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

(I) LEASES

Purchase, extension, and termination options are included in certain of the Company's leases to provide operational flexibility. To measure the lease liability, the Company uses judgement to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options may have changed. The Company also uses estimates to determine its incremental borrowing costs if the interest rate implicit in the lease is not readily determinable.

(J) CONTINGENCIES

Contingencies are subject to measurement uncertainty as the related financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies requires the application of judgements and estimates including the determination of whether a present obligation exists and the reliable estimation of the timing and amount of cash flows required to settle the contingency.

4. Inventory

		2025		2024
Product inventory	$	**736**	$	986
Materials, supplies and other		**1,885**		1,807
	$	**2,621**	$	2,793

During 2025, approximately $33 billion of purchased and produced inventory was recorded as an expense (2024 – approximately $ 30 billion).

5. Exploration and Evaluation Assets

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2023	$ 2,031	$ —	$ 100	$ 77	$ 2,208
Additions, net	102	—	6	—	108
Acquisition of Chevron's assets [1]	320	—	—	—	320
Transfers to property, plant and equipment	(45)	—	—	(7)	(52)
Derecognitions and other [2]	—	—	(62)	—	(62)
Foreign exchange adjustments	—	—	4	—	4
At December 31, 2024	2,408	—	48	70	2,526
Additions/Acquisitions, net [1]	**207**	**—**	**—**	**1**	**208**
Transfers to property, plant and equipment	**(21)**	**—**	**—**	**(14)**	**(35)**
Derecognitions and other [3]	**—**	**—**	**(46)**	**—**	**(46)**
Foreign exchange adjustments	**—**	**—**	**(2)**	**—**	**(2)**
At December 31, 2025	**$ 2,594**	**$ —**	**$ —**	**$ 57**	**$ 2,651**

(1) Refer to note 6 for further details on acquisitions completed in 2024 and 2025.

(2) In connection with the Company's notice of withdrawal from Block 11B/12B in South Africa in 2024, the Company derecognized $ 62 million of exploration and evaluation assets through depletion, depreciation and amortization expense.

(3) In connection with the Company's decision in 2025 to not pursue development of Kossipo in Offshore Africa, the Company derecognized $ 46 million of exploration and evaluation assets through depletion, depreciation and amortization expense.

6. Property, Plant and Equipment

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2023	$ 83,483	$ 8,606	$ 4,409	$ 49,375	$ 484	$ 566	$ 146,923
Additions	3,440	352	205	2,103	11	41	6,152
Acquisition of Chevron's assets	2,585	—	—	6,316	—	—	8,901
Transfers from exploration and evaluation assets	45	—	—	7	—	—	52
Derecognitions [1]	(589)	(18)	—	(456)	—	—	(1,063)
Foreign exchange adjustments and other	—	791	409	—	—	—	1,200
At December 31, 2024	88,964	9,731	5,023	57,345	495	607	162,165
Additions/Acquisitions, net	**4,447**	**1,223**	**547**	**1,841**	**8**	**92**	**8,158**
Transfers from exploration and evaluation assets	**21**	**—**	**—**	**14**	**—**	**—**	**35**
Derecognitions [1]	**(536)**	**(1,207)**	**—**	**(814)**	**—**	**—**	**(2,557)**
AOSP mines acquisition (100%) [2]	**—**	**—**	**—**	**15,488**	**—**	**—**	**15,488**
AOSP mines disposition (90%) [2]	**—**	**—**	**—**	**(12,087)**	**—**	**—**	**(12,087)**
Scotford and Quest disposition (10%) [2]	**—**	**—**	**—**	**(1,217)**	**—**	**—**	**(1,217)**
Foreign exchange adjustments and other	**—**	**(477)**	**(254)**	**—**	**—**	**—**	**(731)**
At December 31, 2025	**$ 92,896**	**$ 9,270**	**$ 5,316**	**$ 60,570**	**$ 503**	**$ 699**	**$ 169,254**
Accumulated depletion and depreciation							
At December 31, 2023	$ 58,840	$ 8,382	$ 3,358	$ 11,105	$ 213	$ 444	$ 82,342
Expense	3,741	96	192	2,086	16	26	6,157
Derecognitions [1]	(589)	(18)	—	(456)	—	—	(1,063)
Recoverability charge	—	160	—	—	—	—	160
Foreign exchange adjustments and other	18	772	335	30	—	—	1,155
At December 31, 2024	62,010	9,392	3,885	12,765	229	470	88,751
Expense	**4,470**	**92**	**97**	**2,538**	**17**	**31**	**7,245**
Derecognitions [1]	**(536)**	**(1,207)**	**—**	**(814)**	**—**	**—**	**(2,557)**
AOSP mines disposition (90%) [2]	**—**	**—**	**—**	**(2,656)**	**—**	**—**	**(2,656)**
Scotford and Quest disposition (10%) [2]	**—**	**—**	**—**	**(206)**	**—**	**—**	**(206)**
Recoverability charges	**—**	**1,462**	**269**	**—**	**—**	**—**	**1,731**
Foreign exchange adjustments and other	**(4)**	**(469)**	**(216)**	**(10)**	**—**	**—**	**(699)**
At December 31, 2025	**$ 65,940**	**$ 9,270**	**$ 4,035**	**$ 11,617**	**$ 246**	**$ 501**	**$ 91,609**
Net book value							
At December 31, 2025	**$ 26,956**	**$ —**	**$ 1,281**	**$ 48,953**	**$ 257**	**$ 198**	**$ 77,645**
At December 31, 2024	$ 26,954	$ 339	$ 1,138	$ 44,580	$ 266	$ 137	$ 73,414

(1) An asset is derecognized when no future economic benefits are expected to arise from its continued use.

(2) Components of the AOSP asset swap are discussed below.

AOSP ASSET SWAP TRANSACTION

On November 1, 2025, pursuant to a 2017 agreement with Shell Canada Limited and affiliates ("Shell") and following the satisfaction of certain conditions, the Company completed the AOSP asset swap with Shell. As a result of the transaction, the Company acquired from Shell, the remaining 10% interest in the AOSP mines, associated reserves, and additional working interests in a number of other non-producing oil sands leases, and in exchange to Shell, a 10% non-operated working interest in the Scotford Upgrader ("Scotford") and Quest Carbon Capture and Storage ("Quest") facilities. As a result, the Company owns and operates 100% of the AOSP mines and retains an 80% non-operated working interest in Scotford and Quest. The transaction had an effective date of March 1, 2025.

The allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities exchanged as at the acquisition date. As a result of obtaining control of the AOSP mines, the transaction was accounted for as a business combination achieved in stages using the acquisition method of accounting. In accordance with IFRS Accounting Standards, at the acquisition date, the Company was deemed to have disposed of its pre-existing interest in the AOSP mines and re-acquired them at fair value, with any gains on remeasurement recognized in net earnings. As a result of the disposition of a 10% non-operated working interest in Scotford and Quest, the Company remeasured the 10% working interest to fair value at the acquisition date, with a gain on disposition recognized in net earnings.

a) Net Assets Acquired and Consideration Exchanged

The following provides a summary of 100% of the identifiable net assets acquired, and the fair value of the consideration exchanged:

($ millions)	Net assets acquired	Purchase consideration/previously held interests	Net
Fair value of the Company's interests in the AOSP mines [1] [2]	$ 15,488	$ (13,939)	$ 1,549
Asset retirement obligation	(685)	616	(69)
Fair value, net of asset retirement obligation	14,803	(13,323)	1,480
Fair value of a 10% interest in Scotford and Quest [2]	—	(1,475)	(1,475)
Cash	153	59	212
Other working capital	8	60	68
Lease assets	1,510	—	1,510
Lease liabilities	(1,510)	—	(1,510)
Deferred income tax liability	(268)	—	(268)
	$ 14,696	$ (14,679)	$ 17
Non-cash gain on disposition of a 10% interest in Scotford and Quest			464
Non-cash gain on remeasurement of the Company's 90%, pre-existing interest in the AOSP mines			4,508
Gain on acquisition, disposition, and remeasurement			$ 4,989

(1) Net assets acquired represent a 100% interest in the AOSP mines, and purchase consideration and previously held interests represent a 90% interest in the AOSP mines.

(2) The Company determined the fair value of the AOSP mines, Scotford and Quest, using an estimate of future cash flows discounted at approximately 18%, with reference to comparable market transactions.

b) Gain on Acquisition, Disposition, and Remeasurement

The Company recognized a $4,989 million gain related to the transaction, comprised of a $ 17 million gain on acquisition representing the excess of the fair value of the net assets acquired compared to the total purchase consideration and previously held interests, a non-cash gain on remeasurement of $4,508 million ($3,471 million after-tax) related to the remeasurement of the previously held interest in the AOSP mines to fair value, and a non-cash gain on disposition of $464 million ($357 million after-tax) related to the disposition of the 10% interest in Scotford and Quest.

The fair value of the Company's interest in the AOSP mines, and non-operated interest in Scotford and Quest was determined in accordance with IFRS Accounting Standards, using an estimate of future cash flows discounted at approximately 18%, with reference to comparable market transactions, including the Company's acquisition of Chevron's assets in December 2024. The valuation incorporated asset-specific assumptions and required the use of level 3 fair value inputs. Key assumptions used in the valuation included the discount rate, estimated future prices, expected future rates of production, quantity of reserves, production expense, capital expenditures, and allocation of fair value between the AOSP mines, Scotford and Quest.

The Company determined that the acquisition date fair value of the previously held interest in the AOSP mines, net of asset retirement obligations, was $13,323 million and utilized this estimate in its measurement of the purchase price consideration. The carrying value of the AOSP mines prior to the gain on remeasurement recorded in the transaction was $8,815 million, net of asset retirement obligations. The Company also determined that the acquisition date fair value of the previously held 10% interest in Scotford and Quest was $ 1,475 million and the associated carrying value prior to the gain on disposition recorded in the transaction was $1,011 million, both net of asset retirement obligations.

In accordance with IFRS Accounting Standards, no value was attributed to potential entity-specific operational synergies. Additionally, the Company has not assigned reserves or attributed any fair value to the additional working interests in non-producing oil sands leases acquired.

c) Actual and Pro Forma Results for AOSP Asset Swap Transaction

As a result of the AOSP asset swap, in the fourth quarter of 2025, revenue increased by approximately $ 143 million and net operating income (comprised of revenue less production, blending and feedstock, and transportation expense) increased by approximately $46 million. Including the impact of interest expense and depletion, depreciation and amortization from operations, earnings before tax increased as a result of the AOSP asset swap by approximately $19 million for the fourth quarter of 2025. Depletion, depreciation and amortization also increased by an additional $24 million for the fourth quarter of 2025 as a result of the gain on remeasurement of its 90% previously held interest in the AOSP mines.

If the AOSP asset swap had been completed on January 1, 2025, the Company estimates that pro forma revenue would have increased by approximately $804 million and pro forma net operating income (comprised of revenue less production, blending and feedstock, and transportation expense) would have increased by approximately $115 million for the year ended December 31, 2025. Including the impact of depletion, depreciation and amortization from operations, the Company estimates pro forma earnings before taxes would have increased by approximately $97 million for the year ended December 31, 2025. Pro forma depletion, depreciation and amortization would have also increased by an additional $145 million in 2025 as a result of the gain on remeasurement of its 90% previously held interest in the AOSP mines. If the Company had accounted for the Corridor pipeline as a lease as of January 1, 2025, pro forma transportation expense would have decreased by $154 million, and pro forma interest expense and depletion, depreciation and amortization would have increased by $ 136 million.

Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2025, or of future results. Pro forma results are based on historical information and reflect actual production in the period available for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

NORTH AMERICA EXPLORATION AND PRODUCTION ACQUISITIONS IN 2025

During 2025, the Company acquired a number of producing and non-producing crude oil and NGLs, and natural gas assets in the North America Exploration and Production segment. These transactions were accounted for using the business combination method of accounting and are summarized below.

a) Grande Prairie NGLs and Natural Gas Acquisition

During 2025, the Company acquired certain producing and non-producing NGLs and natural gas assets in the Grande Prairie area in the North America Exploration and Production segment for cash consideration of $752 million, subject to final closing adjustments. Net assets acquired include exploration and evaluation assets of $36 million, property, plant and equipment of $ 733 million, and other assets of $ 3 million. The Company also assumed associated asset retirement obligations of $20 million. No net deferred tax liabilities were recognized on this transaction.

b) Palliser Block Crude Oil and NGLs, and Natural Gas Acquisition

During 2025, the Company acquired certain producing and non-producing crude oil and NGLs, and natural gas assets in the Palliser Block in the North America Exploration and Production segment, including exploration and evaluation assets of $119 million, property, plant and equipment of $457 million, net working capital of $ 76 million, deferred income tax assets of $ 80 million, and assumed asset retirement obligations of $350 million. Total cash consideration was approximately $ 302 million and is subject to final closing adjustments. The Company recognized a gain on acquisition of $80 million, representing the excess of the fair value of the net assets acquired compared to total purchase consideration.

c) Actual and Pro Forma Results for Grande Prairie and Palliser Block Acquisitions

As a result of the Grande Prairie acquisition, revenue increased by approximately $ 166 million and net operating income (comprised of revenue less production and transportation expense) increased by approximately $89 million for the period subsequent to the acquisition. Including the impact of depletion, depreciation and amortization, earnings before tax increased by approximately $28 million for the period subsequent to the acquisition.

As a result of the Palliser Block acquisition, revenue increased by approximately $ 279 million and net operating income (comprised of revenue less production and transportation expense) increased by approximately $147 million for the period subsequent to the acquisition. Including the impact of depletion, depreciation and amortization, earnings before tax increased by approximately $61 million for the period subsequent to the acquisition.

If the Grande Prairie and Palliser Block acquisitions had been completed on January 1, 2025, the Company estimates that pro forma revenue would have increased by approximately $961 million and pro forma net operating income (comprised of revenue less production and transportation expense) would have increased by approximately $520 million for the year ended December 31, 2025. Including the impact of depletion, depreciation and amortization, the Company estimates pro forma earnings before taxes would have increased by approximately $241 million for the year ended December 31, 2025. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisitions actually occurred on January 1, 2025, or of future results. Pro forma results are based on historical information and reflect actual production in the period available for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition dates.

d) Other Acquisitions

For the year ended December 31, 2025, the Company also acquired a number of other producing and non-producing crude oil and NGLs, and natural gas assets in the North America Exploration and Production segment comprised of exploration and evaluation assets of $17 million, property, plant and equipment of $160 million, and assumed asset retirement and other obligations of $ 51 million for total cash consideration of $126 million.

In February 2026, subsequent to year end, the Company acquired certain producing and non-producing crude oil and NGLs, and natural gas assets in the Peace River area in the North America Exploration and Production segment for cash consideration of approximately $765 million, subject to final closing adjustments. Net assets acquired primarily include exploration and evaluation assets and property, plant and equipment. The Company also assumed associated asset retirement obligations.

INTERNATIONAL MATTERS

a) North Sea

The Company is advancing abandonment and decommissioning activities in the North Sea. Following a 2025 competitive tender for the Ninian South Platform, estimated abandonment costs were higher than originally budgeted. Accordingly, the Company updated its abandonment and decommissioning cost estimates for the Ninian Central and South Platforms and T-Block (Tiffany, Toni, and Thelma fields). Additionally, based on current and forecasted economic conditions, including commodity prices and market egress, the Company determined that the T-Block assets were no longer economically viable. Cessation of production has been accelerated to the first quarter of 2027 and associated crude oil reserves were de-booked.

As a result, during 2025, the Company recognized a non-cash charge of $ 836 million (2024 – $21 million; 2023 – $113 million) comprised of a recoverability charge recognized in depletion, depreciation and amortization expense of $1,462 million (2024 – $160 million; 2023 – $436 million), net of deferred tax recoveries of $626 million (2024 – $139 million; 2023 – $323 million).

The Company's estimate of its asset retirement obligations, including its long-term abandonment projects in the North Sea and associated tax recoveries, are subject to revision in future periods as abandonment activities progress.

b) Offshore Africa

During 2025, the Company determined that it would not pursue an extension of its PSC for the Espoir Field, Block CI-26, in Offshore Africa, and de-booked associated crude oil reserves. The Company is working with the Government of Côte d'Ivoire to facilitate the transition of operatorship in the second half of 2026. As a result, as at December 31, 2025 the Company recognized a non-cash recoverability charge in depletion, depreciation and amortization expense of $269 million.

OTHER MATTERS

As at December 31, 2025, the Company determined that there were no indicators of impairment with respect to its property, plant and equipment and exploration and evaluation assets in the North America Exploration and Production and Oil Sands Mining and Upgrading segments. Although there were no indicators of impairment in these segments, the Company completed its normal course assessment of the recoverability of its property, plant and equipment and exploration and evaluation assets, and determined the carrying amounts of all its CGUs to be recoverable. The recoverability of the International CGUs is discussed in 'International Matters' above.

As at December 31, 2025, as a result of development activities and acquisitions undertaken since the establishment of its CGUs upon adoption of IFRS Accounting Standards, the Company reassessed its CGU structure within the North America Exploration and Production and Oil Sands Mining and Upgrading segments. This reassessment concluded that certain CGUs, which were located in adjacent geographic areas, produce similar products, and which were individually immaterial, should be aggregated into a single CGU. The aggregation of these CGUs did not have any impact on the recoverability of these CGUs under either the previous or revised CGU groupings. There were no changes to the Oil Sands Mining and Upgrading CGUs as a result of the AOSP asset swap, other than for the changing of ownership interest described in 'AOSP Asset Swap Transaction' above.

As at December 31, 2025, property, plant and equipment included project costs, not subject to depletion and depreciation, of $ 466 million in the Oil Sands Mining and Upgrading segment (2024 – $272 million in the Oil Sands Mining and Upgrading segment).

ACQUISITION OF CHEVRON'S ASSETS

In December 2024, the Company completed the acquisition of Chevron's assets for total cash consideration of $ 9,163 million. The acquisition included a 70% operated working interest in the light crude oil and liquids-rich Duvernay asset play in Alberta and a 20% working interest in AOSP. As a result of the acquisition of Chevron's assets, the Company held a 90% direct and indirect working interest in AOSP, which includes the Muskeg River and Jackpine mines, the Scotford Upgrader, and the Quest Carbon Capture and Storage facility. The acquisition also included various working interests in a number of other non-producing oil sands leases. The Company consolidates its interests in the assets, liabilities, revenue, and expenses of both the AOSP and Duvernay joint operations.

The following provides a summary of the net assets acquired relating to the acquisition:

Property, plant and equipment	$ 8,901
Exploration and evaluation assets	320
Working capital	115
Asset retirement obligations	(173)
Net assets acquired	$ 9,163

7. Leases

LEASE ASSETS

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2023	$ 840	$ 482	$ 71	$ 65	$ 1,458
Additions	5	118	40	68	231
Depreciation	(96)	(135)	(51)	(20)	(302)
Foreign exchange adjustments and other	3	3	4	(3)	7
At December 31, 2024	752	468	64	110	1,394
Additions [1]	**1,554**	**413**	**45**	**43**	**2,055**
Depreciation	**(100)**	**(208)**	**(30)**	**(24)**	**(362)**
Derecognitions	**(3)**	**(29)**	**(29)**	**—**	**(61)**
Foreign exchange adjustments and other	**(4)**	**(10)**	**(7)**	**(4)**	**(25)**
At December 31, 2025	**$ 2,199**	**$ 634**	**$ 43**	**$ 125**	**$ 3,001**

(1) During 2025, in connection with the AOSP asset swap (note 6), the Company became the sole contracted shipper on the Corridor pipeline and recognized $ 1,510 million of lease assets, with an associated reduction in the Company's product transportation, purchases, and processing commitments (note 19).

LEASE ASSETS, BY SEGMENT

As at December 31, 2025 and 2024, the Company had the following lease assets by segment:

	2025	2024
Exploration and Production		
North America	**$ 370**	$ 257
North Sea	**32**	25
Offshore Africa	**35**	93
Oil Sands Mining and Upgrading	**2,457**	932
Head Office	**107**	87
	$ 3,001	$ 1,394

LEASE LIABILITIES

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at December 31, 2025 and 2024 were as follows:

		2025		2024
Lease liabilities	**$**	**3,106**	$	1,464
Less: current portion		**373**		255
	$	**2,733**	$	1,209

In addition to the lease assets disclosed above, on an ongoing basis the Company enters into short-term leases related to its Exploration and Production and Oil Sands Mining and Upgrading activities.

Other amounts included in net earnings and cash flows during 2025 and 2024 are provided below:

		2025		2024
Expenses relating to short-term leases [(1)]	**$**	**306**	$	337
Interest expense on lease liabilities	**$**	**74**	$	69
Variable lease payments not included in the measurement of lease liabilities	**$**	**24**	$	59
Total cash outflows for leases [(2)]	**$**	**1,458**	$	1,333

(1) During 2025, the Company capitalized $693 million (2024 – $ 543 million) of short-term leases as additions to property, plant and equipment.

(2) Comprised of cash outflows relating to lease liabilities, short-term leases, and variable lease payments.

8. Investments

INVESTMENT IN PRAIRIESKY ROYALTY LTD.

During 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. ("PrairieSky") for $ 25.65 per common share with net proceeds at close, after fees and expenses, of $575 million. The Company's investment did not constitute significant influence, and was accounted for at fair value through profit or loss, measured at each reporting date. For the year ended December 31, 2024, the Company recognized a gain from investment of $56 million (2023 – $56 million gain) comprised of a fair value gain from investment of $ 50 million (2023 – $34 million gain) and dividend income of $ 6 million (2023 – $22 million).

9. Other Long-Term Assets

		2025		2024
Long-term prepayments, contracts and other [(1)]	**$**	**419**	$	313
Prepaid cost of service tolls		**229**		166
Long-term inventory		**291**		204
Risk management (note 18)		**—**		13
		939		696
Less: current portion		**70**		76
	$	**869**	$	620

(1) Includes physical product sales contracts, interest on Petroleum Revenue Tax ("PRT") and corporate tax recoveries in the North Sea (note 6), and the unamortized cost of contributions to the Company's employee bonus program.

INVESTMENT IN NORTH WEST REDWATER PARTNERSHIP

The Company has a 50% equity investment in NWRP. NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 barrels per day. The refinery processes approximately 50,000 barrels per day of bitumen feedstock, including 12,500 barrels per day of bitumen feedstock for the Company (25% toll payer) and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058 (note 19). Sales of diesel and other refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 21).

As at December 31, 2025, NWRP had $ 1,583 million (December 31, 2024 – $ 1,459 million) outstanding under its unsecured commercial paper program. NWRP has a $1,900 million syndicated credit facility that reserves capacity for amounts outstanding under its commercial paper program and for a debt service reserve equal to six months of anticipated facility interest and fees. As at December 31, 2025, the facility was undrawn.

During 2025, NWRP repaid and cancelled $ 250 million of the non-revolving portion of the syndicated credit facility.

During 2024, NWRP amended its syndicated credit facility to extend the revolving portion originally maturing June 2025 to June 2027, and reduce the authorized limit on the revolving portion by $275 million to $1,900 million. In 2024, NWRP repaid $657 million on its non-revolving facility, and reduced the authorized limit to $250 million.

As at December 31, 2025, NWRP had $8,750 million in long-term notes outstanding (December 31, 2024 – $ 8,750 million).

During 2024, NWRP repaid $500 million of 3.20% series A bonds. Additionally, in 2024 NWRP issued $ 700 million of 4.85% series P bonds due June 2034 and $600 million of 5.08% series Q bonds due June 2054.

NWRP also has short-term borrowings under a $300 million syndicated credit facility ("demand operating facility") (December 31, 2024 – $300 million). As at December 31, 2025, NWRP had borrowings of $50 million under the demand operating facility (December 31, 2024 – $103 million).

The assets, liabilities, partners' equity, product sales, and equity income related to NWRP at December 31, 2025 and 2024 were comprised as follows:

		2025		2024
Current assets	**$**	**493**	$	535
Non-current assets	**$**	**10,298**	$	10,286
Current liabilities	**$**	**2,953**	$	2,082
Non-current liabilities	**$**	**8,829**	$	9,757
Partners' equity	**$**	**(991)**	$	(1,018)
Partners' equity at Company's 50% interest	**$**	**(496)**	$	(509)
Revenue [(1)]	**$**	**1,365**	$	1,490
Net income [(2)]	**$**	**26**	$	92

(1) Included in NWRP's revenue for 2025 is $315 million (2024 – $325 million) related to the Company's 25% share of the refining toll.

(2) Included in the net income for 2025 is the impact of depreciation and amortization expense of $ 265 million (2024 – $346 million) and interest and other financing expense of $ 457 millior (2024 – $502 million).

The carrying value of the Company's interest in NWRP is $ nil, and as at December 31, 2025, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $496 million (2024 – $509 million). The Company's recovery of unrecognized equity losses from NWRP for 2025 was $13 million (2024 – recovery of its share of unrecognized equity losses of $ 46 million; 2023 – unrecognized equity loss of $4 million).

10. Long-Term Debt

		2025		2024
Canadian dollar denominated debt, unsecured				
Medium-term notes				
3.42% debentures due December 1, 2026	**$**	**441**	$	441
2.50% debentures due January 17, 2028		**225**		225
3.30% debentures due December 8, 2028		**550**		—
3.75% debentures due February 8, 2031		**550**		—
4.15% debentures due December 15, 2031		**500**		500
4.55% debentures due February 8, 2036		**550**		—
4.85% debentures due May 30, 2047		**300**		300
		3,116		1,466
US dollar denominated debt, unsecured				
Bank credit facilities (December 31, 2025 – US$ 2,860 million; December 31, 2024 – US$3,393 million)		**3,922**		4,888
Commercial paper (December 31, 2025 – US$ nil; December 31, 2024 – US$ 467 million)		**—**		672
US dollar debt securities				
3.90% due February 1, 2025 (US$ 600 million)		**—**		864
2.05% due July 15, 2025 (US$ 600 million)		**—**		864
3.85% due June 1, 2027 (US$ 1,250 million)		**1,715**		1,801
5.00% due December 15, 2029 (US$ 750 million)		**1,029**		1,080
2.95% due July 15, 2030 (US$ 500 million)		**685**		720
7.20% due January 15, 2032 (US$ 400 million)		**548**		576
6.45% due June 30, 2033 (US$ 350 million)		**480**		504
5.40% due December 15, 2034 (US$ 750 million)		**1,029**		1,080
5.85% due February 1, 2035 (US$ 350 million)		**480**		504
6.50% due February 15, 2037 (US$ 450 million)		**617**		649
6.25% due March 15, 2038 (US$ 1,100 million)		**1,509**		1,585
6.75% due February 1, 2039 (US$ 400 million)		**548**		576
4.95% due June 1, 2047 (US$ 750 million)		**1,029**		1,080
		13,591		17,443
Long-term debt before transaction costs and original issue discounts, net		**16,707**		18,909
Less: original issue discounts, net [1]		**14**		12
transaction costs [1] [2]		**76**		78
		16,617		18,819
Less: current portion of commercial paper		**—**		672
current portion of long-term debt [1] [2]		**441**		1,728
	$	**16,176**	$	16,419

(1) The Company has included unamortized original issue discounts and premiums, and directly attributable transaction costs in the carrying amount of the outstanding debt.

(2) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency, and other professional fees.

BANK CREDIT FACILITIES AND COMMERCIAL PAPER

As at December 31, 2025, the Company had undrawn bank credit facilities of $ 5,668 million, and a fully drawn non-revolving term credit facility of $4,000 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $500 million revolving credit facility, maturing June 2027;
- a $4,000 million non-revolving term credit facility, maturing December 2027;
- a $2,425 million revolving syndicated credit facility, maturing June 2028; and
- a $2,565 million revolving syndicated credit facility, with $ 140 million maturing June 2027, and $2,425 million maturing June 2029.

During 2025, the Company increased its $2,425 million revolving syndicated facility to $2,565 million, and extended $2,425 million originally due June 2027 to June 2029. The remaining $140 million outstanding under this facility will mature in June 2027. Each of the revolving credit facilities are extendible annually at the mutual agreement of the Company and lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

During 2024, the Company extended its $500 million revolving credit facility from February 2025 to February 2026. During 2025, the Company extended its $500 million revolving credit facility originally maturing February 2026 to June 2027.

During 2024, the Company extended its $2,425 million revolving syndicated credit facility originally maturing June 2025 to June 2028.

During 2024 and in connection with the acquisition of Chevron's assets, the Company entered into a $ 4,000 million non-revolving term credit facility maturing December 2027.

Borrowings under the Company's credit facilities may be made by way of pricing referenced to CORRA, SOFR, US base rate or Canadian prime rate.

The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$ 2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2025 was 5.0% (December 31, 2024 – 5.4%), and on total long-term debt outstanding for the year ended December 31, 2025 was 5.0% (December 31, 2024 – 4.9%).

As at December 31, 2025, letters of credit and guarantees aggregating to $ 840 million were outstanding (December 31, 2024 – $ 1,542 million).

MEDIUM-TERM NOTES

During 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $ 3,000 million of medium-term notes in Canada, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

During 2025, the Company issued $550 million of 3.30% medium-term notes due December 2028, $ 550 million of 3.75% medium-term notes due February 2031, and $550 million of 4.55% medium-term notes due February 2036. After issuing these securities, the Company had $1,350 million remaining on its base shelf prospectus.

During 2024, the Company repaid $320 million of 3.55% medium-term notes.

During 2024, the Company issued $500 million of 4.15% medium-term notes due December 2031.

US DOLLAR DEBT SECURITIES

During 2025, the Company repaid US$600 million of 3.90% US dollar debt securities due February 2025.

During 2025, the Company repaid US$600 million of 2.05% US dollar debt securities due July 2025.

During 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$ 4,500 million of debt securities in the United States, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

During 2025, the Company filed a prospectus supplement to the base shelf prospectus. Under the base shelf prospectus, the Company completed the exchange of US$747 million of the outstanding restricted 5.00% US dollar debt securities due December 2029 and US$ 750 million of the outstanding restricted 5.40% US dollar debt securities due December 2034. The exchanged notes were not subject to transfer restrictions and did not impact the Company's level of indebtedness. After the exchange of these securities, the Company had US$3,003 million remaining on its base shelf prospectus.

During 2024, the Company repaid US$500 million of 3.80% US dollar debt securities.

During 2024, the Company issued US$ 750 million of 5.00% notes due December 2029 and US$ 750 million of 5.40% notes due December 2034.

SCHEDULED DEBT REPAYMENTS

Scheduled debt repayments are as follows:

Year		Repayment
2026	$	441
2027	$	5,637
2028	$	775
2029	$	1,029
2030	$	685
Thereafter	$	8,140

11. Other Long-Term Liabilities

		2025		2024
Asset retirement obligations	**$**	**9,743**	$	8,607
Lease liabilities (note 7)		**3,106**		1,464
Share-based compensation		**433**		620
Transportation and processing contracts		**186**		58
Risk management (note 18)		**65**		8
Other		**68**		80
		13,601		10,837
Less: current portion		**1,665**		1,535
	$	**11,936**	$	9,302

ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 4.9% (2024 – 4.8%; 2023 – 5.2%) and inflation rates of up to 2% (2024 – up to 2%; 2023 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

		2025		2024		2023
Balance – beginning of year	**$**	**8,607**	$	7,690	$	6,908
Liabilities incurred		**34**		28		25
Liabilities acquired, net		**489**		171		—
Liabilities settled		**(771)**		(646)		(509)
Asset retirement obligation accretion		**380**		389		366
Revision of cost, inflation, and timing estimates [(1)]		**1,233**		417		621
Change in discount rates		**(129)**		419		314
Foreign exchange adjustments		**(100)**		139		(35)
Balance – end of year [(2)]		**9,743**		8,607		7,690
Less: current portion		**956**		787		634
	$	**8,787**	$	7,820	$	7,056

(1) Includes normal course revisions of cost, inflation, and timing estimates, as well as revisions to decommissioning timing and costs in the North Sea and Offshore Africa (note 6).

(2) The Company's estimate of its total undiscounted and uninflated asset retirement obligations as at December 31, 2025 was $ 17.6 billion (2024 – $ 16.1 billion; 2023 – $ 15.5 billion).

Segmented Asset Retirement Obligations

		2025		2024
Exploration and Production				
North America	$	**4,937**	$	4,783
North Sea		**2,629**		1,724
Offshore Africa		**275**		197
Oil Sands Mining and Upgrading		**1,901**		1,902
Midstream and Refining		**1**		1
	$	**9,743**	$	8,607

Asset Retirement Obligations Sensitivity

Changes in the Company's discount and inflation rates used to estimate its expected future cash outflow required to settle its asset retirement obligations would have the following impact:

		2025		2024
Discount rate				
1% increase	$	**(896)**	$	(883)
1% decrease	$	**1,135**	$	1,132
Inflation rate				
1% increase	$	**1,171**	$	1,166
1% decrease	$	**(934)**	$	(920)

SHARE-BASED COMPENSATION

The liability for share-based compensation includes costs incurred under the Company's Stock Option and PSU Plans. The Company's Stock Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The PSU Plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined with reference to the value of the Company's shares, by individual employee performance, and the extent to which certain other performance measures are met.

The Company recognizes a liability for potential cash settlements under these plans. The current portion of the liability represents the maximum amount of the liability payable within the next twelve month period if all vested stock options and PSUs are settled in cash.

		2025		2024		2023
Balance – beginning of year	$	**620**	$	780	$	832
Share-based compensation expense		**180**		279		491
Cash payment for stock options surrendered and PSUs vested		**(94)**		(84)		(110)
Transferred to common shares		**(273)**		(358)		(435)
Other		**—**		3		2
Balance – end of year		**433**		620		780
Less: current portion		**312**		463		538
	$	**121**	$	157	$	242

Included within share-based compensation liability as at December 31, 2025 was $ 47 million (2024 – $99 million; 2023 – $96 million) related to PSUs granted to certain executive employees.

The fair value of stock options outstanding was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

		2025		2024		2023 [1]
Fair value	**$**	**9.73**	$	13.15	$	17.96
Share price	**$**	**46.49**	$	44.38	$	43.41
Expected volatility		**25.7%**		26.4%		30.9%
Expected dividend yield		**5.1%**		5.1%		4.6%
Risk free interest rate		**2.7%**		2.9%		3.6%
Expected forfeiture rate		**5.3%**		5.2%		5.4%
Expected stock option life [2]		**3.9 years**		4.1 years		4.2 years

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split (note 1).

(2) At original time of grant.

The intrinsic value of vested stock options at December 31, 2025 was $ 121 million (2024 – $181 million; 2023 – $164 million).

12. Income Taxes

The provision for income tax was as follows:

Expense (recovery)		2025		2024		2023
Current corporate income tax – North America [1]	**$**	**2,193**	$	1,654	$	1,853
Current corporate income tax – North Sea		**(124)**		(41)		(6)
Current corporate income tax – Offshore Africa		**16**		57		73
Current PRT [2] – North Sea		**(184)**		(134)		(58)
Other taxes		**10**		(5)		17
Current income tax		**1,911**		1,531		1,879
Deferred corporate income tax		**887**		520		267
Deferred PRT [2] – North Sea		**(377)**		(98)		(214)
Deferred income tax		**510**		422		53
Income tax	**$**	**2,421**	$	1,953	$	1,932

(1) Includes North America Exploration and Production, Oil Sands Mining and Upgrading, and Midstream and Refining segments.

(2) Petroleum Revenue Tax.

For the year ended December 31, 2025, in connection with the AOSP asset swap, the Company recognized deferred corporate income tax of $1,037 million related to the gain on remeasurement of the previously held interest in the AOSP mines, and deferred corporate income tax of $107 million related to the gain on disposition of the 10% interest in Scotford and Quest. Refer to note 6 for further details on the transaction.

For the year ended December 31, 2025, the Company recognized deferred tax recoveries comprised of a deferred corporate income tax recovery of $165 million (2024 – $50 million; 2023 – $118 million) and a deferred PRT recovery of $461 million (2024 – $89 million; 2023 – $205 million) in connection with the increase in the Company's

estimate of future abandonment costs for the planned decommissioning activities at the Ninian field and T-Block in the North Sea (note 6).

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

		2025		2024		2023
Canadian statutory income tax rate		**23.1%**		23.2%		23.3%
Income tax provision at statutory rate	**$**	**3,064**	$	1,870	$	2,364
Effect on income taxes of:						
UK PRT and other taxes		**(551)**		(237)		(255)
Impact of UK PRT and other taxes on corporate income tax		**225**		95		105
Foreign and domestic tax rate differentials		**(94)**		(112)		(104)
Non-taxable portion of capital losses (gains)		**(93)**		114		(35)
Stock options exercised for common shares		**25**		41		91
Revisions arising from prior year tax filings		**1**		43		(174)
Change in unrecognized capital loss carryforward asset		**(93)**		114		(35)
Other		**(63)**		25		(25)
Income tax	**$**	**2,421**	$	1,953	$	1,932

The following table summarizes the temporary differences that give rise to the net deferred income tax liability:

		2025		2024
Deferred income tax liabilities				
Property, plant and equipment and exploration and evaluation assets	**$**	**13,620**	$	12,647
Lease assets		**754**		316
Investment in North West Redwater Partnership		**880**		908
Taxable PRT for corporate income tax		**457**		336
Other		**161**		92
		15,872		14,299
Deferred income tax assets				
Asset retirement obligations		**(2,580)**		(2,437)
Lease liabilities		**(777)**		(332)
Share-based compensation		**(29)**		(35)
Loss carryforwards		**(4)**		(36)
Unrealized foreign exchange loss on long-term debt		**(52)**		(125)
Deferred PRT		**(1,126)**		(795)
Other		**(15)**		—
		(4,583)		(3,760)
Net deferred income tax liability	**$**	**11,289**	$	10,539

Movements in deferred tax assets and liabilities recognized in net earnings during the year were as follows:

		2025		2024		2023
Property, plant and equipment and exploration and evaluation assets	$	**667**	$	443	$	196
Lease assets		**62**		(22)		1
Unrealized foreign exchange on long-term debt		**73**		(86)		28
Unrealized risk management activities		**(14)**		(1)		—
Asset retirement obligations		**(73)**		(279)		(292)
Lease liabilities		**(67)**		26		(3)
Share-based compensation		**6**		(4)		2
Loss carryforwards		**47**		381		235
Investments		**—**		(54)		(2)
Investment in North West Redwater Partnership		**(28)**		4		1
Deferred PRT		**139**		58		86
Taxable PRT for corporate income tax		**(377)**		(98)		(214)
Other		**75**		54		15
	$	**510**	$	422	$	53

The following table summarizes the movements of the net deferred income tax liability during the year:

		2025		2024		2023
Balance – beginning of year	$	**10,539**	$	10,183	$	10,114
Deferred income tax expense		**510**		422		53
Foreign exchange adjustments		**52**		(66)		16
Acquisitions (note 6)		**188**		—		—
Balance – end of year	$	**11,289**	$	10,539	$	10,183

Current income taxes recognized in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's reported results of operations, financial position or liquidity.

The Company has reviewed the Organization for Economic Co-operation and Development's Pillar Two model rules and has concluded it does not have a significant impact.

Deferred income tax assets are recognized for temporary differences to the extent that the realization of the related tax benefit through future taxable profits is probable. Deferred PRT assets will be recovered from the UK Government, directly or through other third parties, as related abandonment expenditures are made. The Company has not recognized deferred income tax assets with respect to taxable capital loss carryforwards in excess of $1,000 million in North America, which can be carried forward indefinitely and only applied against future taxable capital gains. In addition, the Company has not recognized deferred income tax assets related to North American tax pools of approximately $950 million, which can only be claimed against income from certain oil and gas properties.

Deferred income tax liabilities have not been recognized on the unremitted net earnings of wholly controlled subsidiaries. The Company is able to control the timing and amount of distributions and no taxes are payable on distributions from these subsidiaries provided that the distributions remain within certain limits.

13. Share Capital

AUTHORIZED

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	2025		2024	
ISSUED COMMON SHARES	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**2,102,996**	**$ 11,064**	2,144,815	$ 10,712
Issued upon exercise of stock options	**12,062**	**264**	13,531	280
Previously recognized liability on stock options exercised for common shares	**—**	**273**	—	358
Purchase of common shares under Normal Course Issuer Bid	**(33,480)**	**(180)**	(55,350)	(286)
Balance – end of year	**2,081,578**	**$ 11,421**	2,102,996	$ 11,064

PREFERRED SHARES

Preferred shares are issuable in a series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions, and conditions attached to the shares will be determined by the Board of Directors of the Company.

DIVIDENDS

The Company has paid regular quarterly dividends in each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 4, 2026, the Board of Directors approved a 6% increase in the quarterly dividend to $ 0.625 per common share, beginning with the dividend payable on April 7, 2026.

On March 5, 2025, the Board of Directors approved a 4% increase in the quarterly dividend to $ 0.5875 per common share.

On October 7, 2024, the Board of Directors approved a 7% increase in the quarterly dividend to $ 0.5625 per common share. On February 28, 2024, the Board of Directors approved a 5% increase in the quarterly dividend to $ 0.525[(1)] per common share.

NORMAL COURSE ISSUER BID

On March 10, 2025, the Company's application was approved for a Normal Course Issuer Bid ("NCIB") to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 178,738,237 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2025 and ending March 12, 2026.

For the year ended December 31, 2025, the Company purchased 33,480,000 common shares at a weighted average price of $ 43.28 per common share for a total cost, including tax, of $1,467 million. Retained earnings were reduced by $ 1,287 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2025, up to and including March 3, 2026, the Company purchased 3,300,000 common shares at a weighted average price of $ 51.12 per common share for a total cost, including tax, of $ 169 million.

On March 4, 2026, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of Normal Course Issuer Bid, up to 10% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares. Subject to acceptance of the Notice of Intention by the TSX, and applicable securities law, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

SHARE-BASED COMPENSATION – STOCK OPTIONS

The Company's Stock Option Plan provides for the granting of stock options to employees. Stock options granted under the Stock Option Plan have terms ranging from five to six years to expiry and vest over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the TSX on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or 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 of surrender of the stock option.

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split (note 1).

The Stock Option Plan is a "rolling 7%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 7% of the common shares outstanding from time to time.

The following table summarizes information relating to stock options outstanding at December 31, 2025 and 2024:

	2025		2024	
	Stock options (thousands)	**Weighted average exercise price**	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	**50,806**	**$ 33.90**	52,410	$ 26.80
Granted	**19,457**	**$ 43.53**	15,906	$ 44.82
Exercised for common shares	**(12,062)**	**$ 21.86**	(13,531)	$ 20.69
Surrendered for cash settlement	**(524)**	**$ 22.65**	(384)	$ 22.19
Forfeited	**(2,943)**	**$ 38.57**	(3,595)	$ 29.69
Outstanding – end of year	**54,734**	**$ 39.83**	50,806	$ 33.90
Exercisable – end of year	**11,942**	**$ 36.58**	10,033	$ 26.67

The range of exercise prices of stock options outstanding and exercisable at December 31, 2025 was as follows:

	Stock options outstanding			**Stock options exercisable**	
Range of exercise prices	**Stock options outstanding** (thousands)	**Weighted average remaining term** (years)	**Weighted average exercise price**	**Stock options exercisable** (thousands)	**Weighted average exercise price**
$10.38 – $14.99	2,935	0.20	$ 14.56	876	$ 14.36
$15.00 – $19.99	61	0.08	$ 19.36	61	$ 19.36
$20.00 – $24.99	1,105	0.79	$ 20.42	757	$ 20.30
$25.00 – $29.99	481	1.86	$ 27.12	240	$ 27.12
$30.00 – $34.99	4,668	1.49	$ 32.47	1,717	$ 32.41
$35.00 – $39.99	11,278	2.18	$ 39.25	4,285	$ 39.01
$40.00 – $44.99	27,965	4.08	$ 43.10	2,606	$ 42.38
$45.00 – $49.99	5,938	3.76	$ 47.94	1,396	$ 48.51
$50.00 – $52.98	303	4.31	$ 52.98	4	$ 52.98
	54,734	**3.14**	**$ 39.83**	**11,942**	**$ 36.58**

14. Accumulated Other Comprehensive Income

The components of accumulated other comprehensive income, net of taxes, were as follows:

	2025	2024
Derivative financial instruments designated as cash flow hedges	**$ 66**	$ 70
Foreign currency translation adjustment	**153**	231
	$ 219	$ 301

15. Capital Disclosures

The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the ratio of current and long-term debt less cash and cash equivalents divided by the sum of the carrying value of shareholders' equity plus current and long-term debt less cash and cash equivalents. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. As at December 31, 2025, the ratio was within the target range at 26%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS Accounting Standards and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

		2025		2024
Long-term debt	**$**	**16,617**	$	18,819
Less: cash and cash equivalents		**673**		131
Long-term debt, net	**$**	**15,944**	$	18,688
Total shareholders' equity	**$**	**44,366**	$	39,468
Debt to book capitalization		**26%**		32%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2025, the Company was in compliance with this covenant.

16. Net Earnings Per Common Share

			2025		2024		2023 [(1)]
Weighted average common shares outstanding – basic (thousands of shares)			**2,091,134**		2,125,804		2,182,623
Effect of dilutive stock options (thousands of shares)			**6,772**		14,625		21,625
Weighted average common shares outstanding – diluted (thousands of shares)			**2,097,906**		2,140,429		2,204,248
Net earnings		**$**	**10,820**	$	6,106	$	8,233
Net earnings per common share	– basic	**$**	**5.17**	$	2.87	$	3.77
	– diluted	**$**	**5.16**	$	2.85	$	3.74

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split (note 1).

In 2025, the Company excluded 29,366,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share (2024 – 12,144,000; 2023 – 6,461,000).

17. Interest and Other Financing Expense

		2025		2024		2023
Interest expense on long-term debt	**$**	**965**	$	604	$	627
Interest expense on lease liabilities		**74**		69		64
Interest expense on long-term debt and lease liabilities		**1,039**		673		691
Interest (income) and other expense		**(205)**		(81)		(55)
Interest and other financing expense	**$**	**834**	$	592	$	636

18. Financial Instruments

The Company's financial instruments are comprised of cash and cash equivalents, accounts receivable, risk management assets and liabilities, accounts payable, accrued liabilities, lease liabilities, and long-term debt. These financial instruments, with the exception of risk management assets and liabilities, are classified as financial assets and liabilities at amortized cost. Risk management assets and liabilities are classified as derivatives held for trading, cash flow hedges, or embedded derivatives.

The estimated fair values of derivative financial instruments in Level 2 and Level 3 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications, including quoted forward prices for commodities, foreign exchange rates, interest yield curves, and other volatility factors.

The changes in estimated fair values of derivative financial instruments included in the risk management asset (liability) were recognized in the financial statements as follows:

Asset (liability)	**2025**	2024
Balance – beginning of year	**$ 5**	$ 9
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities [1]	**(68)**	(6)
Foreign exchange	**(1)**	1
Other comprehensive income	**(1)**	1
Balance – end of year	**(65)**	5
Less: current portion	**(8)**	5
	$ (57)	$ —

(1) Risk management assets and liabilities are disclosed in note 9 and note 11, respectively.

Net (gain) loss from risk management activities for the years ended December 31, were as follows:

	2025	2024	2023
Net realized risk management (gain) loss	**$ (89)**	$ 168	$ (14)
Net unrealized risk management loss	**71**	9	12
	$ (18)	$ 177	$ (2)

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The Company's financial instruments are categorized as Level 1 with the exception of risk management assets and liabilities, which are categorized as Level 2, and embedded derivatives, which are categorized as Level 3. There were no transfers between Level 1, 2, and 3 financial instruments. The fair values of the Company's fixed rate long-term debt is outlined below:

	2025		2024	
	Carrying amount	**Level 1 Fair Value**	Carrying amount	Level 1 Fair Value
Fixed rate long-term debt [1] [2]	**$ 12,695**	**$ 12,941**	$ 13,259	$ 13,186

(1) The fair value of fixed rate long-term debt has been determined based on quoted market prices.

(2) Includes the current portion of fixed rate long-term debt.

RISK MANAGEMENT

The Company periodically uses derivative financial instruments to manage its commodity price, interest rate, and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)		**2025**		2024
Derivatives held for trading				
Natural gas financial instruments [1] [2] [3]	**$**	**(4)**	$	7
Natural gas embedded derivative [4]		**(57)**		—
Foreign currency forward contracts		**(4)**		(2)
	$	**(65)**	$	5
Included within:				
Current portion of other long-term assets	**$**	**—**	$	13
Current portion of other long-term liabilities		**(8)**		(8)
Other long-term liabilities		**(57)**		—
	$	**(65)**	$	5

(1) In 2025, the Company entered into fixed price financial contracts to buy 12,500 MMBtu/d of natural gas at US$1.30 AECO for the period of August to December 2025, and 25,000 MMBtu/d of natural gas at US$2.16 AECO for the period of January to December 2026.

(2) In 2024, the Company entered into fixed price financial contracts to buy 12,500 MMBtu/d of natural gas at US$1.47 AECO, and 25,000 MMBtu/d of natural gas at US$1.82 AECO for the period of January to December 2025.

(3) In 2023, the Company entered into fixed price financial contracts to buy 50,000 MMBtu/d of natural gas at US$1.82 AECO for the period of January to December 2024.

(4) In 2025, the Company entered into a long-term natural gas supply agreement that contains an embedded derivative.

Embedded Derivative Contract

During 2025, the Company entered into a long-term natural gas supply agreement to supply 140,000 MMBtu/d of natural gas for a term of 15 years, with delivery anticipated to begin in 2030 as all conditions precedent have been waived by the counterparty. Under the terms of the agreement, the Company will deliver natural gas to its counterparty in Illinois, USA and receive a Japan Korea Marker ("JKM") index price less deductions for transportation and liquefaction. The contract includes an embedded derivative as a result of the pricing structure, and the host contract is the natural gas sales agreement with a Chicago Citygate price.

The natural gas embedded derivative contract is categorized as Level 3 within the fair value hierarchy, as the fair value is determined using a discounted estimated cash flow model which incorporates significant unobservable inputs, including future natural gas pricing and a discount rate.

			Range of significant unobservable inputs	
	Remaining term	Fair value ($ millions)	Forward Prices [1] (US$/MMBtu)	Discount Rate
Natural gas embedded derivative liability	2030 – 2045	$ 57	$3.10 – $7.53	4.6 %

(1) Forward prices refers to the differential between JKM and Chicago Citygate prices.

The Company recognizes a (gain) loss on risk management activities in the statements of earnings related to its natural gas embedded derivative. The (gain) loss is determined by the relative movements in fair value compared to the prior period balance sheet date.

The Level 3 fair value measurements of the embedded derivative could be materially impacted by a change in the discount rate and movements in natural gas prices. The following table summarizes the impacts to the fair value of the embedded derivative resulting from changes in the specified variable over the 15-year contract. These sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities.

	JKM price		**Discount rate**	
	US$0.10/MMBtu increase	US$0.10/MMBtu decrease	1% increase	1% decrease
Fair value – increase/(decrease)	$ 52	$ (52)	$ (90)	$ 105

FINANCIAL RISK FACTORS

The Company's financial risks are consistent with those disclosed in notes 1 and 3.

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange rate risk.

COMMODITY PRICE RISK MANAGEMENT

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production, and with natural gas purchases. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

INTEREST RATE RISK MANAGEMENT

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. As at December 31, 2025, the Company had no interest rate swap contracts outstanding.

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper, and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts, foreign currency forward contracts, foreign exchange option contracts, SOFR loans, and commercial paper to mitigate its foreign currency exchange rate risk.

As at December 31, 2025, the Company had US$ 1,500 million of foreign currency forward contracts outstanding (December 31, 2024 – US$2,187 million), with original terms of up to 90 days, all of which were designated as derivatives held for trading (December 31, 2024 – US$1,521 million), and US$nil were designated as cash flow hedges (December 31, 2024 – US$ 666 million).

As at December 31, 2025, the Company had no foreign currency put option contracts outstanding. The Company periodically sells put option contracts which grant the purchaser the right, but not the obligation, to exercise the contract on the expiry date (European option) and are designated as derivatives held for trading. The amount that may be payable upon exercise is initially recognized as a liability valued at the amount paid by the counterparty. The option is remeasured to fair value at each reporting date with gains and losses recognized in risk management activities in net earnings. If the option expires unexercised, the remaining liability is derecognized.

FINANCIAL INSTRUMENT SENSITIVITIES

The following table summarizes the annualized sensitivities of the Company's 2025 net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2025, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those disclosed in the Company's other continuous disclosure documents, are limited to the impact of changes in a specified variable applied to financial instruments only, and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear. These sensitivities exclude the impacts of the Company's embedded derivative, disclosed above.

	2025		2024	
	Increase (decrease) to net earnings	**Increase (decrease) to other comprehensive income**	Increase (decrease) to net earnings	Increase (decrease) to other comprehensive income
Interest rate risk				
Increase interest rate 1%	**$ (33)**	**$ —**	$ (46)	$ —
Decrease interest rate 1%	**$ 33**	**$ —**	$ 46	$ —
Foreign currency exchange rate risk				
Weakening of the Canadian dollar by US$ 0.01	**$ (189)**	**$ —**	$ (255)	$ —
Strengthening of the Canadian dollar by US$ 0.01	**$ 184**	**$ —**	$ 248	$ —

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

COUNTERPARTY CREDIT RISK MANAGEMENT

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and, where appropriate, ensuring that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at December 31, 2025, the Company had 2 customers (2024 – 1; 2023 – 3), that are major international energy companies with investment grade ratings, that individually accounted for more than 10% of the Company's annual sales. As at December 31, 2025, substantially all of the Company's accounts receivable were due within normal trade terms, and the average expected credit loss was approximately 2% of the Company's accounts receivable balance (December 31, 2024 – 2%).

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. As at December 31, 2025, the Company had net risk of $nil with specific counterparties related to derivative financial instruments (December 31, 2024 – $11 million). The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper, and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates of the Company's financial liabilities were as follows:

As at December 31, 2025	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	**$ 1,105**	**$ —**	**$ —**	**$ —**
Accrued liabilities	**$ 4,255**	**$ —**	**$ —**	**$ —**
Long-term debt [1]	**$ 441**	**$ 5,637**	**$ 2,489**	**$ 8,140**
Other long-term liabilities [2]	**$ 381**	**$ 268**	**$ 659**	**$ 1,863**
Interest and other financing expense [3]	**$ 971**	**$ 910**	**$ 1,860**	**$ 3,678**

As at December 31, 2024	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 1,079	$ —	$ —	$ —
Accrued liabilities	$ 4,525	$ —	$ —	$ —
Long-term debt [1]	$ 2,400	$ 941	$ 7,494	$ 8,074
Other long-term liabilities [2]	$ 263	$ 187	$ 405	$ 617
Interest and other financing expense [3]	$ 1,024	$ 951	$ 1,978	$ 3,574

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, $ 373 million (2024 – $ 255 million); one to less than two years, $268 million (2024 – $ 187 million); two to less than five years, $ 654 million (2024 – $ 405 million); and thereafter, $ 1,811 million (2024 – $ 617 million).

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2025 and December 31, 2024, respectively.

19. Commitments and Contingencies

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2025:

	2026	2027	2028	2029	2030	Thereafter
Product transportation, purchases, and processing [1] [2] [3] [4]	$ 2,241	$ 2,223	$ 2,065	$ 1,912	$ 1,758	$ 18,025
North West Redwater Partnership service toll [5]	$ 116	$ 95	$ 96	$ 95	$ 95	$ 3,878
Offshore vessels and equipment	$ 99	$ —	$ —	$ —	$ —	$ —
Field equipment and power [4]	$ 50	$ 26	$ 26	$ 24	$ 24	$ 170
Other	$ 122	$ 50	$ 19	$ 18	$ 18	$ 177

(1) The Company's commitment for its 20-year product transportation agreement ending in 2044 on the Trans Mountain Expansion ("TMX") pipeline reflects interim tolls approved by the Canada Energy Regulator in 2023, and is subject to change pending the approval of final tolls.

(2) In 2025, in connection with the AOSP asset swap (note 6), the Company became the sole contracted shipper on the Corridor pipeline. Previously, the Company recognized a commitment associated with the pipeline, however, following the completion of the AOSP asset swap the contract has been recorded as a lease.

(3) During 2024, the Company increased its total committed capacity on the TMX pipeline to 169,000 bbl/d, an incremental 75,000 bbl/d over the 20-year term.

(4) During 2024, the acquisition of Chevron's assets included approximately $ 1,292 million of product transportation and processing commitments and approximately $ 75 million of field equipment and power commitments.

(5) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $ 1,792 million of interest payable over the 40-year tolling period, ending in 2058 (note 9).

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement, and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

20. Supplemental Disclosure of Cash Flow Information

	2025	2024	2023
Changes in non-cash working capital:			
Accounts receivable	**$ 125**	$ (940)	$ 368
Inventory	**166**	(616)	(219)
Prepaids and other	**(22)**	(42)	(23)
Accounts payable	**84**	(340)	78
Accrued liabilities	**(316)**	851	(812)
Current income tax liabilities	**504**	326	(1,558)
Other long-term liabilities	**23**	(106)	(200)
Net changes in non-cash working capital	**$ 564**	$ (867)	$ (2,366)
Relating to:			
Operating activities	**$ 672**	$ (743)	$ (2,417)
Investing activities	**(108)**	(124)	51
	$ 564	$ (867)	$ (2,366)

The following table summarizes movements in the Company's liabilities arising from financing activities for the years ended December 31, 2025 and 2024:

	Long-term debt	Lease liabilities	Liabilities from financing activities
At December 31, 2023	$ 10,799	$ 1,555	$ 12,354
Changes from financing cash flows:			
Issuance of bank credit facilities and commercial paper, net [1]	5,466	—	5,466
Issuance of other long-term debt [1]	2,639	—	2,639
Repayment of other long-term debt [1]	(1,008)	—	(1,008)
Payment of lease liabilities	—	(325)	(325)
Non-cash changes:			
Lease additions	—	231	231
Changes in foreign exchange and fair value [2]	923	3	926
At December 31, 2024	$ 18,819	$ 1,464	$ 20,283
Changes from financing cash flows:			
Repayment of bank credit facilities and commercial paper, net [1]	**(1,395)**	**—**	**(1,395)**
Issuance of other long-term debt [1]	**1,634**	**—**	**1,634**
Repayment of other long-term debt [1]	**(1,699)**	**—**	**(1,699)**
Payment of lease liabilities	**—**	**(361)**	**(361)**
Non-cash changes:			
Lease additions	**—**	**2,055**	**2,055**
Lease derecognitions	**—**	**(61)**	**(61)**
Changes in foreign exchange and fair value [2]	**(742)**	**9**	**(733)**
At December 31, 2025	**$ 16,617**	**$ 3,106**	**$ 19,723**

(1) Includes original issue discounts and premiums, and directly attributable transaction costs.

(2) Includes foreign exchange (gains) losses, the amortization of original issue discounts and premiums and directly attributable transaction costs .

21. Segmented Information

The Company's exploration and production activities are conducted in three geographic segments: North America, North Sea and Offshore Africa. These activities include the exploration, development, production, and marketing of crude oil, natural gas liquids, and natural gas. The Company's Oil Sands Mining and Upgrading activities are reported in a separate segment from exploration and production activities. Midstream and Refining activities include the Company's pipeline operations, an electricity co-generation system, and NWRP.

Segmented revenue and segmented results include transactions between business segments. Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers are based on the location of the seller.

	North America			North Sea			Offshore Africa		
(millions of Canadian dollars)	**2025**	2024	2023	**2025**	2024	2023	**2025**	2024	2023
Segmented product sales									
Crude oil and NGLs [1] [2]	**$ 19,102**	$ 18,740	$ 17,375	**$ 325**	$ 467	$ 435	**$ 164**	$ 434	$ 577
Natural gas [1]	**2,287**	1,415	2,375	**13**	7	7	**30**	42	51
Other income and revenue	**92**	6	10	**—**	4	—	**1**	4	9
Total segmented product sales	**21,481**	20,161	19,760	**338**	478	442	**195**	480	637
Less: royalties	**(2,529)**	(2,876)	(2,443)	**(1)**	(1)	(1)	**(8)**	(24)	(57)
Segmented revenue	**18,952**	17,285	17,317	**337**	477	441	**187**	456	580
Segmented expenses									
Production	**3,567**	3,249	3,617	**469**	440	342	**79**	109	141
Blending and feedstock [2] [3]	**4,344**	4,643	4,568	**—**	—	—	**—**	—	—
Transportation [3]	**2,032**	1,541	1,240	**10**	10	7	**—**	1	1
Depletion, depreciation and amortization [4]	**4,582**	3,831	3,679	**1,573**	279	494	**432**	297	213
Asset retirement obligation accretion	**221**	231	234	**64**	65	46	**9**	9	8
Risk management loss (commodity derivatives)	**66**	7	24	**—**	—	—	**—**	—	—
Gain on acquisitions, disposition, and remeasurement	**(80)**	—	—	**—**	—	—	**—**	—	—
Total segmented expenses	**14,732**	13,502	13,362	**2,116**	794	889	**520**	416	363
Segmented earnings (loss)	**$ 4,220**	$ 3,783	$ 3,955	**$ (1,779)**	$ (317)	$ (448)	**$ (333)**	$ 40	$ 217
Non-segmented expenses									
Administration									
Share-based compensation									
Interest and other financing expense									
Risk management (gain) loss (other)									
Foreign exchange (gain) loss									
Gain from investment									
Total non-segmented expenses									
Earnings before taxes									
Current income tax									
Deferred income tax									
Net earnings									

(1) Product sales in the North America Exploration and Production and Oil Sands Mining and Upgrading segments originate in Canada.

(2) Includes blending and feedstock costs associated with the processing of third party bitumen and other purchased feedstock in the Oil Sands Mining and Upgrading segment.

(3) During 2025, the Company revised its presentation of transportation, blending and feedstock costs, showing the expenses on a disaggregated basis. The comparative periods presented have been updated to reflect the revision (note 1).

(4) Includes a $1,462 million (2024 – $160 million; 2023 – $436 million) non-cash recoverability charge for revisions to abandonment and decommissioning costs in the North Sea, a $269 million non-cash recoverability charge related to the decision to not pursue an extension of the Company's PSC for the Espoir field in Offshore Africa, and a $ 46 million non-cash derecognition of exploration and evaluation assets related to the decision to not pursue development of Kossipo in Offshore Africa (notes 5 and 6).

Inter-segment Elimination and Other includes internal and corporate transportation and electricity charges. Production, processing, and other purchasing and selling activities, that are not included in the preceding segments are also reported in the segmented information as Inter-segment Elimination and Other.

Operating segments have been determined based on the nature of the Company's activities and the geographic locations in which the Company operates, and are consistent with the level of information regularly provided to and reviewed by the Company's chief operating decision makers.

Oil Sands Mining and Upgrading			Midstream and Refining			Inter-segment Elimination and Other			Total		
2025	2024	2023	**2025**	2024	2023	**2025**	2024	2023	**2025**	2024	2023
$ 20,112	$ 19,263	$ 18,661	**$ 91**	$ 82	$ 76	**$ 946**	$ 98	$ 176	**$ 40,740**	$ 39,084	$ 37,300
—	—	—	**—**	—	—	**120**	104	142	**2,450**	1,568	2,575
204	16	5	**670**	813	926	**10**	14	10	**977**	857	960
20,316	19,279	18,666	**761**	895	1,002	**1,076**	216	328	**44,167**	41,509	40,835
(2,867)	(2,952)	(2,366)	**—**	—	—	**—**	—	—	**(5,405)**	(5,853)	(4,867)
17,449	16,327	16,300	**761**	895	1,002	**1,076**	216	328	**38,762**	35,656	35,968
4,693	3,921	3,989	**284**	315	332	**63**	59	59	**9,155**	8,093	8,480
2,218	2,462	2,253	**503**	669	646	**1,006**	157	265	**8,071**	7,931	7,732
684	497	310	**42**	16	18	**(17)**	(12)	(6)	**2,751**	2,053	1,570
2,780	2,258	2,011	**17**	16	16	**—**	—	—	**9,384**	6,681	6,413
86	84	78	**—**	—	—	**—**	—	—	**380**	389	366
—	—	—	**—**	—	—	**—**	—	—	**66**	7	24
(4,989)	—	—	**—**	—	—	**—**	—	—	**(5,069)**	—	—
5,472	9,222	8,641	**846**	1,016	1,012	**1,052**	204	318	**24,738**	25,154	24,585
$ 11,977	$ 7,105	$ 7,659	**$ (85)**	$ (121)	$ (10)	**$ 24**	$ 12	$ 10	**$ 14,024**	$ 10,502	$ 11,383
									615	503	452
									180	279	491
									834	592	636
									(84)	170	(26)
									(762)	955	(279)
									—	(56)	(56)
									783	2,443	1,218
									13,241	8,059	10,165
									1,911	1,531	1,879
									510	422	53
									$ 10,820	$ 6,106	$ 8,233

CAPITAL EXPENDITURES [1]

	2025			2024		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ 115**	**$ 71**	**$ 186**	$ 406	$ (29)	$ 377
Offshore Africa	**—**	**(46)**	**(46)**	6	(62)	(56)
Oil Sands Mining and Upgrading	**—**	**(13)**	**(13)**	—	(7)	(7)
	115	**12**	**127**	412	(98)	314
Property, plant and equipment						
Exploration and Production						
North America [3]	**4,249**	**(317)**	**3,932**	5,627	(146)	5,481
North Sea	**16**	**—**	**16**	39	295	334
Offshore Africa	**467**	**80**	**547**	197	8	205
	4,732	**(237)**	**4,495**	5,863	157	6,020
Oil Sands Mining and Upgrading [3] [4]	**1,844**	**1,381**	**3,225**	8,104	(134)	7,970
Midstream and Refining	**8**	**—**	**8**	11	—	11
Head Office	**92**	**—**	**92**	41	—	41
	6,676	**1,144**	**7,820**	14,019	23	14,042
	$ 6,791	**$ 1,156**	**$ 7,947**	$ 14,431	$ (75)	$ 14,356

(1) This table provides a reconciliation of capitalized costs, reported in note 5 and note 6, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

(2) Derecognitions, asset retirement obligations, transfer of exploration and evaluation assets, and other fair value adjustments.

(3) Includes cash consideration paid of $320 million for exploration and evaluation assets and $ 2,553 million for property, plant and equipment within the North America Exploration and Production segment, and $6,175 million for property, plant and equipment within the Oil Sands Mining and Upgrading segment acquired from Chevron in 2024 (note 6).

(4) Includes the non-cash gain on remeasurement and gain on disposition related to the AOSP asset swap completed in 2025 (note 6).

SEGMENTED ASSETS

	2025	2024
Exploration and Production		
North America	**$ 33,462**	$ 32,670
North Sea	**789**	702
Offshore Africa	**1,398**	1,412
Other	**35**	31
Oil Sands Mining and Upgrading	**54,699**	49,221
Midstream and Refining	**1,142**	1,099
Head Office	**305**	224
	$ 91,830	$ 85,359

22. Remuneration of Directors and Senior Management

REMUNERATION OF NON-MANAGEMENT DIRECTORS

		2025	2024	2023
Fees earned	**$**	**3**	$ 3	$ 3

REMUNERATION OF SENIOR MANAGEMENT[1]

		2025	2024	2023
Salary	**$**	**2**	$ 2	$ 2
Common stock option based awards		**7**	11	13
Annual incentive plans		**6**	6	5
Long-term incentive plans		**19**	20	19
	$	**34**	$ 39	$ 39

(1) Senior management identified above are consistent with the disclosure on Named Executive Officers provided in the Company's Information Circular to shareholders for the respective years.



CANADIAN NATURAL RESOURCES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2025

MARCH 4, 2026

Management's Discussion and Analysis

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Definitions and Abbreviations

AECO	Alberta natural gas reference location
AIF	Annual Information Form
AOSP	Athabasca Oil Sands Project
API	specific gravity measured in degrees on the American Petroleum Institute scale
ARO	asset retirement obligations
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Bitumen	a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons that are too heavy or thick to flow at reservoir conditions, and recoverable at economic rates using thermal in situ recovery methods
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
Brent	Dated Brent
C$	Canadian dollars
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
CORRA	Canadian Overnight Repo Rate Average
Crude oil	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, thermal bitumen, and synthetic crude oil
E&P	Exploration and Production
FASB	Financial Accounting Standards Board
FPSO	Floating Production, Storage and Offloading Vessel
GHG	greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Horizon	Horizon Oil Sands
IFRS Accounting Standards	International Financial Reporting Standards as issued by the International Accounting Standards Board
Mbbl	thousand barrels
Mbbl/d	thousand barrels per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMBtu/d	million British thermal units per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MOU	Memorandum of Understanding between the Government of Canada and the Government of Alberta.
NGLs	natural gas liquids
NWRP	North West Redwater Partnership
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OPEC+	Organization of the Petroleum Exporting Countries Plus
PRT	Petroleum Revenue Tax
SCO	synthetic crude oil. Includes all crude oil blends (including mining bitumen) produced from Horizon, AOSP mines and Scotford Upgrader.
SEC	United States Securities and Exchange Commission
SOFR	Secured Overnight Financing Rate
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US$	United States dollars
WCS	Western Canadian Select
WCS Heavy Differential	WCS Heavy Differential from WTI
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate reference location at Cushing, Oklahoma

Advisory

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "focus", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration", or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to the Company's strategy or strategic focus, capital budget, expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, forecast and anticipated abandonment expenditures, income tax expenses, and other targets provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, including the strength of the Company's balance sheet, the sources and adequacy of the Company's liquidity, and the flexibility of the Company's capital structure, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to: the Company's assets at Horizon, AOSP, the Primrose thermal oil projects ("Primrose"), the Pelican Lake water and polymer flood projects ("Pelican Lake"), the Kirby thermal oil sands project ("Kirby"), the Jackfish thermal oil sands project ("Jackfish") and the North West Redwater bitumen upgrader and refinery; construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, NGLs, or SCO that the Company may be reliant upon to transport its products to market; the maintenance of the Company's facilities and any expected return to service dates; the construction, expansion, or maintenance of third-party facilities that process the Company's products; the abandonment and decommissioning of certain assets and the timing thereof; the development and deployment of technology and technological innovations; the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long-term; and the materiality of the impact of tax interpretations and litigation on the Company's results, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives, or expectations upon which they are based will occur. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas, and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates, and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance, or achievements of the Company to be materially different from any future results, performance, or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of the actions of OPEC+, the impact of conflicts in the Middle East, in Ukraine and in Venezuela, the restriction or disruption of global trade routes, the impact of changes to US economic policy, increased inflation, and the risk of decreased economic activity resulting from a global recession) which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil, natural gas and NGLs prices; the impact of the ramp-up of LNG Canada on commodity prices; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; changes and uncertainties in the international trade environment, including with respect to tariffs, export restrictions, embargoes, and key trade agreements (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded); uncertainty in the regulatory framework governing GHG emissions including, among other things, financial and other support from various levels of government for climate related initiatives and potential emissions or production caps, and the implementation of the MOU in November 2025; civil unrest and political uncertainty, including changes in government, actions of or against terrorists, insurgent groups, or other conflict including conflict between states; the ability of the Company to prevent and recover from a cyberattack, other cyber-related crime, and other cyber-related incidents; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling, and other equipment; ability of the Company to complete capital programs; the Company's ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting, or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in the mining, extracting, or upgrading the Company's bitumen products; availability and cost of financing; the Company's success of exploration and development

activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets, including the acquisition of the remaining interest in the AOSP mines and other acquisitions that occurred in 2025; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; changes to future abandonment and decommissioning costs; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety, competition, environmental laws and regulations, and the impact of climate change initiatives on capital expenditures and production expenses); interpretations of applicable tax and competition laws and regulations; asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short-, medium-, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; the impact of legal proceedings to which the Company is party; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial, state, and local laws and regulations such as restrictions on production or emissions, the imposition of tariffs, embargoes, or export restrictions on the Company's products (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded), changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations (including the implementation of the MOU). Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this MD&A could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity, and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements in this MD&A, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A includes references to non-GAAP measures, which include non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure ("NI 52-112"). Non-GAAP measures are used by the Company to evaluate its financial performance, financial position, or cash flow. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided in the 'Non-GAAP and Other Financial Measures' section of this MD&A.

SPECIAL NOTE REGARDING COMMON SHARE SPLIT AND COMPARATIVE FIGURES

At the Company's Annual and Special Meeting held on May 2, 2024, shareholders passed a Special Resolution approving a two for one common share split effective for shareholders of record as of market close on June 3, 2024. On June 10, 2024, shareholders of record received one additional share for every one common share held, with common shares trading on a split-adjusted basis beginning June 11, 2024. Common share, per common share, dividend, and stock option amounts for periods prior to the two for one common share split have been updated to reflect the common share split.

SPECIAL NOTE REGARDING AMENDMENTS TO THE *COMPETITION ACT* (CANADA)

On June 20, 2024, amendments to the *Competition Act* (Canada) came into force with the adoption of Bill C-59, *An Act to Implement Certain Provisions of the Fall Economic Statement*, which impact environmental and climate disclosures by businesses. As a result of these amendments, certain public representations by a business regarding the benefits of the work it is doing to protect or restore the environment or mitigate the environmental and ecological causes or effects of climate change may violate the *Competition Act's* deceptive marketing practices provisions. Subsequently, on November 4, 2025, the federal government tabled the 2025 Budget, which proposed further amendments to the *Competition Act*, namely removing the requirement that businesses substantiate their environmental representations about a business or business activity based on an internationally recognized methodology, and eliminating private rights of action under the revised business-activity greenwashing provision. Uncertainty surrounding the interpretation and enforcement of this legislation, which includes the status of any proposed or future amendments, may expose the Company to increased litigation and financial penalties, the outcome and impacts of which can be difficult to assess or quantify and may have a material adverse effect on the Company's business, reputation, financial condition, and results.

SPECIAL NOTE REGARDING CURRENCY, FINANCIAL INFORMATION, PRODUCTION AND RESERVES

This MD&A should be read in conjunction with the Company's audited consolidated financial statements for the year ended December 31, 2025. It should also be read in conjunction with the Company's MD&A for the three months and year ended December 31, 2025. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's audited consolidated financial statements for the year ended December 31, 2025 and this MD&A have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards").

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalties" or "company gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, thermal bitumen, and SCO (including mining bitumen). Production on an "after royalties" or "company net" basis is also presented for information purposes only.

The following discussion and analysis refers primarily to the Company's 2025 financial results compared to 2024 and 2023, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2026. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its quarterly MD&A for the three months and year ended December 31, 2025, its Annual Information Form for the year ended December 31, 2025, and its audited consolidated financial statements for the year ended December 31, 2025, is available on SEDAR+ at www.sedarplus.ca, and on EDGAR at www.sec.gov. Information on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated March 4, 2026.

Objectives and Strategy

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value on a per common share basis through the economic and sustainable development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives and its commitments to environmental stewardship and safety excellence.

The Company endeavors to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments, and focuses on creating long-term shareholder value, including through its dividend and share buyback programs, in accordance with its capital allocation policy. The Company allocates its capital by maintaining:

- Balance among its products, namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil [(1)], thermal bitumen, SCO, and natural gas;
- A large, balanced, diversified, high quality, long life low decline asset base;
- Balance among acquisitions, development and exploration;
- Balance between sources and terms of debt financing and a strong financial position; and
- Commitment to environmental stewardship throughout the decision-making process.

The Company's three-phase crude oil marketing strategy includes:

- Blending various crude oil streams with diluents to create more attractive feedstock;
- Expanding market access for crude oil and natural gas by supporting and participating in pipeline and infrastructure projects that add incremental transportation capacity to existing and new markets; and
- Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil and thermal bitumen.

Operational discipline, safe, effective and efficient operations, and cost control are fundamental to the Company and embrace the key piece of the Company's mission statement: "doing it right". By consistently managing costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are attained by developing area knowledge, and by maintaining high working interests and operator status in the Company's properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to develop its reserves, execute on growth projects and take advantage of favourable acquisition opportunities. Additionally, the Company periodically utilizes its risk management hedging program to reduce the risk of volatility in commodity prices and foreign exchange rates, and corresponding cash flows.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt and equity financing to selectively acquire properties generating future cash flows in its core areas. The Company's financial discipline, commitment to a strong balance sheet, and capacity to internally generate cash flows provide the means to responsibly and sustainably grow in the long term.

(1) Pelican Lake heavy crude oil is 12–17º API oil, which receives medium quality crude netbacks due to lower production expense and lower royalty rates.

Financial and Operational Highlights

($ millions, except per common share amounts)			2025		2024		2023 [1]
Product sales [2]		$	**44,167**	$	41,509	$	40,835
Crude oil and NGLs		$	**40,740**	$	39,084	$	37,300
Natural gas		$	**2,450**	$	1,568	$	2,575
Net earnings		$	**10,820**	$	6,106	$	8,233
Per common share	– basic	$	**5.17**	$	2.87	$	3.77
	– diluted	$	**5.16**	$	2.85	$	3.74
Adjusted net earnings from operations [3]		$	**7,444**	$	7,414	$	8,533
Per common share	– basic [4]	$	**3.56**	$	3.49	$	3.91
	– diluted [4]	$	**3.55**	$	3.46	$	3.87
Cash flows from operating activities		$	**15,106**	$	13,386	$	12,353
Adjusted funds flow [3]		$	**15,460**	$	14,859	$	15,274
Per common share	– basic [4]	$	**7.39**	$	6.99	$	7.00
	– diluted [4]	$	**7.37**	$	6.94	$	6.93
Dividends declared per common share [5]		$	**2.35**	$	2.14	$	1.85
Total assets		$	**91,830**	$	85,359	$	75,955
Long-term debt, net [6]		$	**15,944**	$	18,688	$	9,922
Cash flows used in investing activities		$	**6,687**	$	14,095	$	4,858
Net capital expenditures [3]		$	**6,579**	$	14,431	$	4,909
Abandonment expenditures		$	**771**	$	646	$	509
Average realized price							
Crude oil and NGLs – Exploration and Production ($/bbl) [4]		$	**71.54**	$	77.76	$	72.36
Natural gas – Exploration and Production ($/Mcf) [7]		$	**2.51**	$	1.86	$	3.10
SCO – Oil Sands Mining and Upgrading ($/bbl) [4]		$	**86.41**	$	98.03	$	100.06
Daily production, before royalties (BOE/d)			**1,570,757**		1,363,496		1,332,105
Crude oil and NGLs (bbl/d)			**1,146,175**		1,005,603		973,530
Natural gas (MMcf/d) [8]			**2,547**		2,147		2,151

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split. Further details are disclosed in the 'Advisory' section of this MD&A and in note 1 to the Company's audited consolidated financial statements.

(2) Further details related to product sales are disclosed in note 21 to the Company's audited consolidated financial statements.

(3) Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(4) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(5) On March 4, 2026, the Board of Directors approved a 6% increase in the quarterly dividend to $0.625 per common share, beginning with the dividend payable on April 7, 2026. On March 5, 2025, the Board of Directors approved a 4% increase in the quarterly dividend to $0.5875 per common share. On October 7, 2024, the Board of Directors approved a 7% increase in the quarterly dividend to $0.5625 per common share. On February 28, 2024, the Board of Directors approved a 5% increase in the quarterly dividend to $0.525 per common share. On November 1, 2023, the Board of Directors approved an 11% increase in the quarterly dividend to $0.50 per common share. On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.45 per common share.

(6) Capital management measure. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(7) Calculated as natural gas sales divided by sales volumes.

(8) Natural gas production volumes approximate sales volumes.

CONSOLIDATED NET EARNINGS AND ADJUSTED NET EARNINGS FROM OPERATIONS

For 2025, the Company reported net earnings of $10,820 million compared with $6,106 million for 2024 (2023 – $8,233 million). Net earnings for 2025 included non-operating income, net of tax, of $3,376 million compared with non-operating losses of $1,308 million for 2024 (2023 – non-operating losses of $300 million) related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on financing activities, the gain from investment, the gain on acquisitions, disposition, and remeasurement, and recoverability charges related to the North Sea and Offshore Africa. Excluding these items, adjusted net earnings from operations for 2025 were $7,444 million compared with $7,414 million for 2024 (2023 – $8,533 million).

The increase in net earnings and adjusted net earnings from operations for 2025 compared with 2024 primarily reflected:

- higher sales volumes in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGLs sales volumes in the North America Exploration and Production segment; and
- higher realized natural gas pricing and sales volumes in the North America Exploration and Production segment;

partially offset by:

- lower realized SCO pricing[(1)] in the Oil Sands Mining and Upgrading segment; and
- lower realized crude oil and NGLs pricing[(1)] in the North America Exploration and Production segment.

A detailed reconciliation of the changes in the Company's product sales is provided in the 'Analysis of Changes in Product Sales' section of this MD&A.

The impacts of depletion, depreciation and amortization, share-based compensation, risk management activities, foreign exchange (gain) loss, the gain on acquisitions, disposition, and remeasurement, the gain from investme nt, and recoverability charges related to the North Sea and Offshore Africa also contributed to the increase in net earnings for 2025 from 2024. These items are discussed in detail in the relevant sections of this MD&A. The AOSP asset swap is discussed below, and the recoverability charges related to the North Sea and Offshore Africa are discussed in detail in the 'Adjusted Depletion, Depreciation and Amortization – Exploration and Production' section of this MD&A.

AOSP ASSET SWAP TRANSACTION

On November 1, 2025, the Company completed the AOSP asset swap with Shell Canada Limited and affiliates ("Shell"). As a result of the transaction, the Company acquired from Shell, the remaining 10% interest in the AOSP mines, associated reserves, and additional working interests in a number of other non-producing oil sands leases, and in exchange to Shell, a 10% non-operated working interest in the Scotford Upgrader ("Scotford") and Quest Carbon Capture and Storage ("Quest") facilities. As a result, the Company owns and operates 100% of the AOSP mines and retains an 80% non-operated working interest in Scotford and Quest. The transaction had an effective date of March 1, 2025.

The Company recognized a $4,989 million gain related to the transaction, comprised of a $17 million gain on acquisition representing the excess of the fair value of the net assets acquired compared to the total purchase consideration and previously held interests, a non-cash gain of $4,508 million ($3,471 million after-tax) related to the remeasurement of the previously held interest in the AOSP mines to fair value, and a non-cash gain on disposition of $464 million ($357 million after-tax) related to the disposition of the 10% interest in Scotford and Quest. Further details are disclosed in note 6 to the Company's audited consolidated financial statements.

CASH FLOWS FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

Cash flows from operating activities for 2025 were $15,106 million compared with $13,386 million for 2024 (2023 – $12,353 million). The increase in cash flows from operating activities for 2025 from 2024 were primarily due to the factors previously noted related to the fluctuations in adjusted net earnings from operations, together with the impact of net changes in non-cash working capital.

Adjusted funds flow for 2025 was $15,460 million ($7.39 per common share) compared with $14,859 million ($6.99 per common share) for 2024 (2023 – $15,274 million; $7.00 per common share[(2)]). The increase in adjusted funds flow for 2025 from 2024 was primarily due to the factors noted above related to the increase in cash flows from operating activities, excluding the impact of the net change in non-cash working capital, abandonment expenditures, and movements in other long-term assets, including the unamortized cost of contributions to the Company's employee bonus program, interest on PRT and corporate tax recoveries, and prepaid cost of service tolls.

PRODUCTION VOLUMES

Record crude oil and NGLs production before royalties for 2025 of 1,146,175 bbl/d increased 14% from 1,005,603 bbl/d in 2024 (2023 – 973,530 bbl/d). Natural gas production before royalties for 2025 averaged 2,547 MMcf/d, an increase of 19% from 2,147 MMcf/d in 2024 (2023 – 2,151 MMcf/d). Total production before royalties for 2025 of 1,570,757 BOE/d increased 15% from 1,363,496 BOE/d in 2024 (2023 – 1,332,105 BOE/d). Crude oil and NGLs and natural gas production volumes are discussed in detail in the 'Daily Production' section of this MD&A.

(1) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(2) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split. Further details are disclosed in the 'Advisory' section of this MD&A and in note 1 to the Company's audited consolidated financial statements.

PRODUCT PRICES

In the Company's Exploration and Production segments, the 2025 realized crude oil and NGLs pric es decreased 8% to average $71.54 per bbl from $77.76 per bbl in 2024 (2023 – $72.36 per bbl), and the 2025 realized natural gas pric e increased 35% to average $2.51 per Mcf from $1.86 per Mcf in 2024 (2023 – $3.10 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2025 realized SCO sales price averaged $86.41 per bbl, a decrease of 12% from $98.03 per bbl in 2024 (2023 – $100.06 per bbl). The Company's realized product pricing is reflective of the prevailing benchmark pricing. Crude oil and NGLs and natural gas prices are discussed in detail in the 'Business Environment and Outlook', 'Realized Product Prices – Exploration and Production', and the 'Realized Product Prices, Royalties and Transportation – Oil Sands Mining and Upgrading' sections of this MD&A.

PRODUCTION EXPENSE

In the Company's Exploration and Production segments, the 2025 crude oil and NGLs production expense [(1)] averaged $14.33 per bbl, comparable with $14.72 per bbl in 2024 (2023 – $16.12 per bbl), and natural gas production expense[(1)] averaged $1.14 per Mcf in 2025, a decrease of 7% from $1.22 per Mcf in 2024 (2023 – $1.30 per Mcf). In the Oil Sands Mining and Upgrading segment, the 2025 production expense[(1)] averaged $22.66 per bbl, comparable with $22.88 per bbl in 2024 (2023 – $24.32 per bbl). Crude oil and NGLs and natural gas production expense is discussed in detail in the 'Production Expense – Exploration and Production' and the 'Production Expense – Oil Sands Mining and Upgrading' sections of this MD&A.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

The following is a summary of the Company's quarterly financial results for the eight most recently completed quarters:

($ millions, except per common share amounts)

2025	**Total**	**Dec 31**	**Sep 30**	**Jun 30**	**Mar 31**
Product sales [(1)]	**$ 44,167**	**$ 10,710**	**$ 11,070**	**$ 9,675**	**$ 12,712**
Crude oil and NGLs	**$ 40,740**	**$ 9,666**	**$ 10,468**	**$ 8,874**	**$ 11,732**
Natural gas	**$ 2,450**	**$ 735**	**$ 399**	**$ 600**	**$ 716**
Net earnings	**$ 10,820**	**$ 5,303**	**$ 600**	**$ 2,459**	**$ 2,458**
Net earnings per common share					
– basic	**$ 5.17**	**$ 2.55**	**$ 0.29**	**$ 1.17**	**$ 1.17**
– diluted	**$ 5.16**	**$ 2.54**	**$ 0.29**	**$ 1.17**	**$ 1.17**

2024	Total	Dec 31	Sep 30	Jun 30	Mar 31[(2)]
Product sales [(1)]	$ 41,509	$ 11,064	$ 10,401	$ 10,622	$ 9,422
Crude oil and NGLs	$ 39,084	$ 10,381	$ 9,943	$ 10,084	$ 8,676
Natural gas	$ 1,568	$ 451	$ 257	$ 331	$ 529
Net earnings	$ 6,106	$ 1,138	$ 2,266	$ 1,715	$ 987
Net earnings per common share					
– basic	$ 2.87	$ 0.54	$ 1.07	$ 0.80	$ 0.46
– diluted	$ 2.85	$ 0.54	$ 1.06	$ 0.80	$ 0.46

(1) Further details related to product sales are disclosed in note 21 to the Company's audited consolidated financial statements.

(2) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split. Further details are disclosed in the 'Advisory' section of this MD&A and in note 1 to the Company's audited consolidated financial statements.

Volatility in the quarterly net earnings over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – Fluctuations in global supply/demand including crude oil production levels from OPEC+ and its impact on world supply, the impact of geopolitical and market uncertainties (including those due to the conflicts in the Middle East, Ukraine and Venezuela, and the impacts of ongoing tariff and trade uncertainty) on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the start-up of the Trans Mountain Expansion ("TMX") pipeline in 2024, the impact of the WCS Heavy Differential from WTI in North America, and the impact of the differential between WTI and Brent benchmark pricing in the International segments.
- **Natural gas pricing** – Fluctuations in both the demand for natural gas and inventory storage levels, the impact of third-party pipeline maintenance and outages, the impact of geopolitical and market uncertainties, the impact of seasonal conditions, the impact of liquefied natural gas ("LNG") demand and exports, and the impact of shale gas production in the US.

(1) Calculated as respective production expense divided by respective sales volumes.

- **Crude oil and NGLs sales volumes** – Fluctuations in production from Kirby and Jackfish, fluctuations in production due to the cyclic nature of Primrose, fluctuations in the Company's drilling program in the North America Exploration and Production segment, natural field declines, the impact of turnarounds in the Oil Sands Mining and Upgrading segment, the impact and timing of acquisitions (including the acquisition of working interests in AOSP and Duvernay assets in 2024, the acquisition of assets in the Palliser block and the Grande Prairie area in 2025, and the AOSP asset swap in 2025), wildfires, and maintenance activities in the North America Exploration and Production segment. Sales volumes in the International segments also reflected fluctuations due to the timing of liftings, planned abandonment activities in the North Sea, and temporary suspension of production at Baobab in Offshore Africa for planned FPSO maintenance.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's drilling program in the North America Exploration and Production segment, the impact and timing of acquisitions (including the acquisition of a working interest in the Duvernay assets in 2024, and the acquisition of assets in the Palliser block and the Grande Prairie area in 2025), natural field declines, the impact of seasonal conditions, and wildfires in the North America Exploration and Production segment.
- **Production expense** – Fluctuations primarily due to the impacts of the demand and cost for services, fluctuations in product mix and production volumes, seasonal conditions, carbon tax, fluctuating energy costs, inflationary cost pressures, cost optimizations across all segments, turnarounds in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Depletion, depreciation and amortization expense** – Fluctuations due to changes in sales volumes, timing of acquisitions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, the impact of turnarounds in the Oil Sands Mining and Upgrading segment, and recoverability charges related to the North Sea and Offshore Africa.
- **Share-based compensation** – Fluctuations due to the measurement of fair market value of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Interest expense** – Fluctuations due to changing long-term debt levels and lease liabilities, the impact of movements in benchmark interest rates on outstanding floating rate long-term debt, and interest on PRT and corporate tax recoveries.
- **Foreign exchange** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt and working capital.
- **Gain on acquisitions, disposition, and remeasurement** – A gain on acquisitions representing the excess of the fair value of the net assets acquired compared to total purchase consideration and previously held interests, a gain on remeasurement to fair value of the Company's pre-existing 90% interest in the AOSP mines as part of the AOSP asset swap, and a gain on disposition of the 10% interest in Scotford and Quest disposed of as part of the AOSP asset swap.

Business Environment and Outlook

Global crude oil benchmark pricing declined through the fourth quarter of 2025 as increasing global supply outpaced relatively modest demand growth, which remained subdued amid ongoing tariff and trade uncertainty. Late in the fourth quarter of 2025, escalating geopolitical tensions contributed to heightened concerns regarding potential crude oil supply disruptions entering into 2026. Natural gas benchmark pricing increased during the fourth quarter of 2025, driven by seasonal demand factors and continued strength in LNG export activity out of the US Gulf Coast. In Canada, AECO benchmark pricing improved due to robust export volumes out of the WCSB. The ongoing ramp-up of LNG Canada is expected to further increase LNG demand and support AECO pricing in 2026.

During 2025, the US government announced tariffs on certain Canadian goods. While these actions have contributed to market volatility, including commodity price and foreign currency volatility, these tariffs have not had a material impact on the Company's financial results as of the date of this MD&A. The duration of these trade actions remains uncertain, and broader changes to US economic policy may have a material effect on the Company's business, financial conditions, or results in future periods. The Company will continue to monitor and assess the implications of any current or emerging US economic policies.

BENCHMARK COMMODITY PRICES

(Yearly average)		2025		2024		2023
WTI benchmark price (US$/bbl)	**$**	**64.77**	$	75.72	$	77.61
Dated Brent benchmark price (US$/bbl)	**$**	**69.02**	$	80.75	$	82.61
WCS Heavy Differential from WTI (US$/bbl)	**$**	**11.10**	$	14.73	$	18.62
SCO price (US$/bbl)	**$**	**64.42**	$	75.09	$	79.64
Condensate benchmark price (US$/bbl)	**$**	**63.32**	$	72.94	$	76.55
NYMEX benchmark price (US$/MMBtu)	**$**	**3.43**	$	2.27	$	2.74
AECO benchmark price (C$/GJ)	**$**	**1.76**	$	1.36	$	2.77
US/Canadian dollar average exchange rate (US$)	**$**	**0.7155**	$	0.7300	$	0.7409
US/Canadian dollar year end exchange rate (US$)	**$**	**0.7292**	$	0.6942	$	0.7573

Substantially all of the Company's production is sold based on US dollar benchmark pricing, with crude oil marketed based on WTI and Brent indices, and natural gas marketed using a diversified mix of AECO- and NYMEX-based pricing. The Company's realized prices are directly impacted by fluctuations in foreign exchange rates resulting in product revenues being impacted by changes in Canadian dollar sales prices relative to the US dollar benchmark prices.

Crude oil sales contracts in North America are typically based on WTI benchmark pricing. WTI averaged US$64.77 per bbl for 2025, a decrease of 14% from US$75.72 per bbl for 2024 (2023 – US$77.61 per bbl).

Crude oil sales contracts for the Company's International segments are typically based on Brent benchmark pricing, which is representative of international markets and overall global supply and demand. Brent averaged US$69.02 per bbl for 2025, a decrease of 15% from US$80.75 per bbl for 2024 (2023 – US$82.61 per bbl).

The decrease in WTI and Brent benchmark pricing for 2025 from 2024 primarily reflected increased global supply and inventory builds driven by near-record production from non-OPEC+ producers and higher OPEC+ output. Supply gains exceeded global demand growth, which remained muted amid ongoing tariff and trade uncertainty.

The WCS Heavy Differential averaged US$11.10 per bbl for 2025 compared with US$14.73 per bbl for 2024 (2023 – US$18.62 per bbl). The narrowing of the WCS Heavy Differential for 2025 from 2024 primarily reflected full year takeaway capacity on the TMX pipeline and strong US Gulf Coast heavy oil pricing.

The SCO price averaged US$64.42 per bbl for 2025, a decrease of 14% from US$75.09 per bbl for 2024 (2023 – US$79.64 per bbl). The decrease in SCO pricing for 2025 from 2024 primarily reflected weaker WTI benchmark pricing.

NYMEX benchmark pricing averaged US$3.43 per MMBtu for 2025, an increase of 51% from US$2.27 per MMBtu for 2024 (2023 – US$2.74 per MMBtu). The increase in NYMEX natural gas pricing for 2025 from 2024 primarily reflected lower US inventory levels in the first half of 2025, combined with record LNG exports out of the US Gulf Coast.

AECO benchmark pricing averaged $1.76 per GJ for 2025, an increase of 29% from $1.36 per GJ for 2024 (2023 – $2.77 per GJ). The increase in AECO natural gas pricing for 2025 from 2024 primarily reflected higher NYMEX benchmark pricing and increased exports out of the WCSB.

Analysis of Changes in Product Sales

($ millions)	2023	Changes due to Volumes	Prices	Other	2024	Changes due to Volumes	Prices	Other	2025
North America									
Crude oil and NGLs	$ 17,375	$ 283	$ 1,082	$ —	$ 18,740	**$ 2,392**	**$ (2,030)**	**$ —**	**$ 19,102**
Natural gas	2,375	3	(963)	—	1,415	**261**	**611**	**—**	**2,287**
Other [1]	10	—	—	(4)	6	**—**	**—**	**86**	**92**
	19,760	286	119	(4)	20,161	**2,653**	**(1,419)**	**86**	**21,481**
North Sea									
Crude oil and NGLs	435	30	2	—	467	**(95)**	**(47)**	**—**	**325**
Natural gas	7	1	(1)	—	7	**4**	**2**	**—**	**13**
Other [1]	—	—	—	4	4	**—**	**—**	**(4)**	**—**
	442	31	1	4	478	**(91)**	**(45)**	**(4)**	**338**
Offshore Africa									
Crude oil and NGLs	577	(142)	(1)	—	434	**(260)**	**(10)**	**—**	**164**
Natural gas	51	(7)	(2)	—	42	**(13)**	**1**	**—**	**30**
Other [1]	9	—	—	(5)	4	**—**	**—**	**(3)**	**1**
	637	(149)	(3)	(5)	480	**(273)**	**(9)**	**(3)**	**195**
Oil Sands Mining and Upgrading									
Crude oil and NGLs	18,661	823	(221)	—	19,263	**4,138**	**(3,289)**	**—**	**20,112**
Other [1]	5	—	—	11	16	**—**	**—**	**188**	**204**
	18,666	823	(221)	11	19,279	**4,138**	**(3,289)**	**188**	**20,316**
Midstream and Refining									
Midstream activities	76	—	—	6	82	**—**	**—**	**9**	**91**
Refined product sales and other [1]	926	—	—	(113)	813	**—**	**—**	**(143)**	**670**
	1,002	—	—	(107)	895	**—**	**—**	**(134)**	**761**
Inter-segment Elimination and Other [2]									
Product sales	318	—	—	(116)	202	**—**	**—**	**864**	**1,066**
Other [1]	10	—	—	4	14	**—**	**—**	**(4)**	**10**
	328	—	—	(112)	216	**—**	**—**	**860**	**1,076**
Total	$ 40,835	$ 991	$ (104)	$ (213)	$ 41,509	**$ 6,427**	**$ (4,762)**	**$ 993**	**$ 44,167**

(1) Includes the sale of diesel and other refined products, and other income.

(2) Eliminates internal transportation and electricity charges and includes production, processing and other purchasing and selling activities that are not included in the above segments.

Product sales increased 6% to $44,167 million for 2025 from $41,509 million for 2024 (2023 – $40,835 million). Th e increase in total product sales was primarily due to higher SCO sales volumes in the Oil Sands Mining and Upgrading segment; and higher crude oil and NGLs sales volumes, together with higher realized natural gas pricing and sales volumes in the North America Exploration and Production segment; partially offset by lower realized SCO pricing and lower realized crude oil and NGLs pricing in the Oil Sands Mining and Upgrading and North America Exploration and Production segments, respectively. Crude oil and NGLs and natural gas pricing are discussed in detail in the 'Business Environment and Outlook', 'Exploration and Production' and 'Oil Sands Mining and Upgrading' sections of this MD&A. Crude oil and NGLs and natural gas production volumes are discussed in detail in the 'Daily Production' section of this MD&A.

For 2025, 1% of t he Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2024 – 2%; 2023 – 3%). North Sea accounted for 1% of crude oil and NGLs and natural gas product sales for 2025 (2024 – 1%; 2023 – 1%), and Offshore Africa accounted for less than 1% of crude oil and NGLs and natural gas product sales for 2025 (2024 – 1%; 2023 – 2%).

Daily Production

DAILY PRODUCTION, BEFORE ROYALTIES

	2025	2024	2023
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**569,401**	509,288	496,100
North America – Oil Sands Mining and Upgrading [1]	**565,102**	472,245	451,339
International – Exploration and Production			
North Sea	**8,468**	11,536	12,639
Offshore Africa	**3,204**	12,534	13,452
Total International [2]	**11,672**	24,070	26,091
Total Crude oil and NGLs	**1,146,175**	1,005,603	973,530
Natural gas (MMcf/d) [3]			
North America	**2,538**	2,136	2,139
International			
North Sea	**3**	2	2
Offshore Africa	**6**	9	10
Total International	**9**	11	12
Total Natural gas	**2,547**	2,147	2,151
Total Barrels of oil equivalent (BOE/d)	**1,570,757**	1,363,496	1,332,105
Product mix			
Light and medium crude oil and NGLs	**11%**	10%	10%
Pelican Lake heavy crude oil	**3%**	3%	3%
Primary heavy crude oil	**6%**	6%	6%
Thermal bitumen	**17%**	20%	20%
Synthetic crude oil [1]	**36%**	35%	34%
Natural gas	**27%**	26%	27%
Percentage of product sales [1] [4] [5]			
Crude oil and NGLs	**94%**	96%	93%
Natural gas	**6%**	4%	7%

(1) SCO production before royalties excludes SCO consumed internally as diesel.

(2) "International" includes North Sea and Offshore Africa Exploration and Production segments in all instances used in this MD&A.

(3) Natural gas production volumes approximate sales volumes.

(4) Net of blending and feedstock costs and excluding risk management activities.

(5) Excluding Midstream and Refining revenue.

DAILY PRODUCTION, NET OF ROYALTIES

	2025	2024	2023
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**476,850**	408,237	406,534
North America – Oil Sands Mining and Upgrading (1)	**467,415**	386,171	385,996
International – Exploration and Production			
North Sea	**8,451**	11,509	12,609
Offshore Africa	**3,061**	11,918	12,183
Total International	**11,512**	23,427	24,792
Total Crude oil and NGLs	**955,777**	817,835	817,322
Natural gas (MMcf/d)			
North America	**2,466**	2,091	2,055
International			
North Sea	**3**	2	2
Offshore Africa	**6**	9	10
Total International	**9**	11	12
Total Natural gas	**2,475**	2,102	2,067
Total Barrels of oil equivalent (BOE/d)	**1,368,198**	1,168,209	1,161,852

(1) SCO production net of royalties excludes SCO consumed internally as diesel.

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, thermal bitumen, SCO, and natural gas.

Total 2025 production before royalties averaged 1,570,757 BOE/d, an increase of 15% from 1,363,496 BOE/d in 2024 (2023 – 1,332,105 BOE/d).

Record crude oil and NGLs production before royalties for 2025 averaged 1,146,175 bbl/d, an increase of 14% from 1,005,603 bbl/d for 2024 (2023 – 973,530 bbl/d). The increase in crude oil and NGLs production before royalties for 2025 from 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, strong utilization in the Oil Sands Mining and Upgrading segment, and strong drilling results in the North America Exploration and Production segment.

Annual crude oil and NGLs production before royalties for 2025 was within the Company's previously issued production target of 1,137,000 bbl/d and 1,151,000 bbl/d. Annual crude oil and NGLs production before royalties for 2026 is now targeted to average between 1,188,000 bbl/d and 1,229,000 bbl/d. Production targets constitute forward-looking statements. Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

Natural gas production before royalties accounted for 27% of the Company's total production in 2025 on a BOE basis. Record natural gas production before royalties for 2025 averaged 2,547 MMcf/d, an increase of 19% from 2,147 MMcf/d for 2024 (2023 – 2,151 MMcf/d). The increase in natural gas production before royalties for 2025 from 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, combined with strong drilling results in the Company's liquids-rich natural gas assets.

Annual natural gas production before royalties for 2025 was within the Company's previously issued production target of 2,535 MMcf/d and 2,575 MMcf/d. Annual natural gas production before royalties for 2026 is now targeted to average between 2,560 MMcf/d and 2,615 MMcf/d. Production targets constitute forward-looking statements. Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

North America – Exploration and Production

Record North America crude oil and NGLs production before royalties for 2025 averaged 569,401 bbl/d, an increase of 12% from 509,288 bbl/d for 2024 (2023 – 496,100 bbl/d). The increase in North America crude oil and NGLs production before royalties for 2025 from 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, combined with strong drilling results.

Thermal oil production before royalties for 2025 averaged 275,086 bbl/d, comparable with 271,011 bbl/d for 2024 (2023 – 262,000 bbl/d).

Pelican Lake heavy crude oil production before royalties averaged 42,470 bbl/d for 2025, a decrease of 5% from 44,779 bbl/d for 2024 (2023 – 47,078 bbl/d) reflecting Pelican Lake's long life low decline production.

Record North America natural gas production before royalties for 2025 aver aged 2,538 MMcf/d, an increase of 19% from 2,136 MMcf/d for 2024 (2023 – 2,139 MMcf/d). The increase in natural gas production before royalties for 2025 from 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, combined with strong drilling results in the Company's liquids-rich natural gas assets.

North America – Oil Sands Mining and Upgrading

Record SCO production before royalties for 2025 averaged 565,102 bbl/d, an increase of 20% from 472,245 bbl/d for 2024 (2023 – 451,339 bbl/d). The increase in SCO production before royalties for 2025 from 2024 primarily reflected the acquisition completed in December 2024, combined with strong utilization.

International – Exploration and Production

International crude oil and NGLs production before royalties for 2025 averaged 11,672 bbl/d, a decrease of 52% from 24,070 bbl/d for 2024 (2023 – 26,091 bbl/d). The decrease in International crude oil and NGLs production before royalties for 2025 from 2024 primarily reflected the temporary suspension of production at Baobab in Offshore Africa due to planned maintenance on its FPSO, which is expected to return to service in the second quarter of 2026, planned North Sea abandonments conducted as part of the previously announced decommissioning plans, and natural field declines.

Exploration and Production

OPERATING HIGHLIGHTS

		2025		2024		2023
Crude oil and NGLs ($/bbl) [1]						
Realized price [2]	**$**	**71.54**	$	77.76	$	72.36
Transportation [3]		**7.02**		5.50		4.23
Realized price, net of transportation [2]		**64.52**		72.26		68.13
Royalties [4]		**11.53**		14.85		12.55
Production expense [5]		**14.33**		14.72		16.12
Netback [2]	**$**	**38.66**	$	42.69	$	39.46
Natural gas ($/Mcf) [1]						
Realized price [6]	**$**	**2.51**	$	1.86	$	3.10
Transportation [3]		**0.59**		0.62		0.56
Realized price, net of transportation		**1.92**		1.24		2.54
Royalties [4]		**0.08**		0.05		0.13
Production expense [5]		**1.14**		1.22		1.30
Netback [7]	**$**	**0.70**	$	(0.03)	$	1.11
Barrels of oil equivalent ($/BOE) [1]						
Realized price [2]	**$**	**47.98**	$	50.82	$	50.54
Transportation [3]		**5.54**		4.78		3.88
Realized price, net of transportation [2]		**42.44**		46.04		46.66
Royalties [4]		**6.90**		8.96		7.77
Production expense [5]		**11.18**		11.73		12.74
Netback [2]	**$**	**24.36**	$	25.35	$	26.15

(1) For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

(2) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(3) Calculated as transportation expense divided by respective sales volumes.

(4) Calculated as royalties divided by respective sales volumes.

(5) Calculated as production expense divided by respective sales volumes.

(6) Calculated as natural gas sales divided by natural gas sales volumes.

(7) Natural gas netbacks exclude NGLs netbacks derived from the Company's liquids-rich natural gas plays.

REALIZED PRODUCT PRICES – EXPLORATION AND PRODUCTION

		2025		2024		2023
Crude oil and NGLs ($/bbl) [1]						
North America [2]	**$**	**70.90**	$	76.37	$	70.51
International average [3]	**$**	**98.07**	$	108.80	$	107.46
North Sea [3]	**$**	**97.26**	$	111.53	$	110.99
Offshore Africa [3]	**$**	**99.71**	$	106.00	$	106.25
Crude oil and NGLs average [2]	**$**	**71.54**	$	77.76	$	72.36
Natural gas ($/Mcf) [1] [3]						
North America	**$**	**2.47**	$	1.81	$	3.04
International average	**$**	**12.45**	$	12.01	$	12.81
North Sea	**$**	**11.77**	$	9.93	$	10.45
Offshore Africa	**$**	**12.77**	$	12.46	$	13.19
Natural gas average	**$**	**2.51**	$	1.86	$	3.10
Average ($/BOE) [1] [2]	**$**	**47.98**	$	50.82	$	50.54

(1) For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

(2) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(3) Calculated as crude oil and NGLs sales, and natural gas sales divided by respective sales volumes.

North America

North America realized crude oil and NGLs prices decreased 7% to average $70.90 per bbl for 2025 from $76.37 per bbl for 2024 (2023 – $70.51 per bbl), primarily reflecting lower WTI benchmark pricing, partially offset by a narrowing of the WCS Heavy Differential.

The Company remains focused on its crude oil blending and marketing strategy, which includes expanding market access within existing pipeline infrastructure, supporting pipeline projects that increase transportation capacity to new markets, and collaborating with refiners to enhance heavy conversion capacity. During 2025, the Company contributed approximately 223,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 36% to average $2.47 per Mcf for 2025 from $1.81 per Mcf for 2024 (2023 – $3.04 per Mcf). The increase in realized natural gas prices per Mcf for 2025 from 2024 primarily reflected higher AECO benchmark and export pricing.

The prices received in the North America Exploration and Production segment by product type were as follows:

(Yearly average)		2025		2024		2023
Wellhead Price [1]						
Light and medium crude oil and NGLs ($/bbl)	**$**	**65.77**	$	69.42	$	70.72
Pelican Lake heavy crude oil ($/bbl)	**$**	**75.07**	$	82.83	$	77.69
Primary heavy crude oil ($/bbl)	**$**	**73.74**	$	81.97	$	75.67
Thermal bitumen ($/bbl)	**$**	**72.42**	$	76.57	$	67.62
Natural gas ($/Mcf)	**$**	**2.47**	$	1.81	$	3.04

(1) Amounts expressed on a per unit basis are based on sales volumes of the respective product type.

International

International realized crude oil and NGLs prices averaged $98.07 per bbl for 2025, a decrease of 10% from $108.80 per bbl for 2024 (2023 – $107.46 per bbl). Realized crude oil and NGLs prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, prevailing Brent benchmark prices and foreign exchange rates at the time of lifting.

ROYALTIES – EXPLORATION AND PRODUCTION

		2025		2024		2023
Crude oil and NGLs ($/bbl) [1]						
North America	**$**	**11.77**	$	15.40	$	12.89
International average	**$**	**1.56**	$	2.75	$	5.99
North Sea	**$**	**0.15**	$	0.26	$	0.33
Offshore Africa	**$**	**4.41**	$	5.30	$	10.08
Crude oil and NGLs average	**$**	**11.53**	$	14.85	$	12.55
Natural gas ($/Mcf) [1]						
North America	**$**	**0.08**	$	0.04	$	0.13
Offshore Africa	**$**	**0.59**	$	0.57	$	0.62
Natural gas average	**$**	**0.08**	$	0.05	$	0.13
Average ($/BOE) [1]	**$**	**6.90**	$	8.96	$	7.77

(1) Calculated as royalties divided by respective sales volumes. For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

North America

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less production, capital, and abandonment costs incurred.

North America crude oil and NGLs and natural gas royalties for 2025 and the comparable periods reflect ed movements in benchmark commodity prices, fluctuations in the WCS Heavy Differential and the impact of sliding scale royalty rates.

Crude oil and NGLs royalty rates [(1)] averaged approximately 17% of product sales for 2025 compared with 20% of product sales for 2024 (2023 – 18%). The decrease in royalty rates for 2025 from 2024 primari ly reflected lower benchmark pricing and the impact of sliding scale royalty rates.

Natural gas royalty rates averaged approximately 3% of product sales for 2025 compared with 2% of product sales for 2024 (2023 – 4%). Th e increase in royalty rates for 2025 from 2024 primarily reflected higher prevailing benchmark pricing.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital expenditures and production expenses, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 4% for 2025 compared with 5% of product sales for 2024 (2023 – 9%). Royalty rates as a percentage of product sales reflected the timing of liftings, and the status of payout in the various fields.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

		2025		2024		2023
Crude oil and NGLs ($/bbl) [1]						
North America	**$**	**12.19**	$	12.55	$	14.46
International average	**$**	**103.48**	$	62.99	$	48.16
North Sea	**$**	**136.47**	$	103.28	$	85.57
Offshore Africa	**$**	**36.73**	$	21.77	$	21.14
Crude oil and NGLs average	**$**	**14.33**	$	14.72	$	16.12
Natural gas ($/Mcf) [1]						
North America	**$**	**1.11**	$	1.19	$	1.27
International average	**$**	**9.23**	$	6.51	$	7.26
North Sea	**$**	**12.18**	$	8.95	$	9.85
Offshore Africa	**$**	**7.80**	$	5.98	$	6.83
Natural gas average	**$**	**1.14**	$	1.22	$	1.30
Average ($/BOE) [1]	**$**	**11.18**	$	11.73	$	12.74

(1) Calculated as production expense divided by respective sales volumes. For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

(1) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

North America

North America crude oil and NGLs production expense for 2025 averaged $12.19 per bbl, comparable with $12.55 per bbl for 2024 (2023 – $14.46 per bbl).

North America natural gas production expense for 2025 averaged $1.11 per Mcf, a decrease of 7% from $1.19 per Mcf for 2024 (2023 – $1.27 per Mcf). The decrease in natural gas production expense per Mcf for 2025 from 2024 primarily reflected higher production volumes.

International

International crude oil and NGLs production expense for 2025 averag ed $103.48 per bbl, an increase of 64% fro m $62.99 per bbl for 2024 (2023 – $48.16 per bbl). The increase in crude oil and NGLs production expense per bbl for 2025 from 2024 primarily reflected activities at Ninian in the pre-cessation period, the timing of liftings from various fields that have different cost structures, and the impact of foreign exchange.

ADJUSTED DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		**2025**		2024		2023
North America	**$**	**4,582**	$	3,831	$	3,679
North Sea		**1,573**		279		494
Offshore Africa		**432**		297		213
Depletion, depreciation and amortization	**$**	**6,587**	$	4,407	$	4,386
Less: Recoverability charges [1]		**1,777**		222		436
Adjusted depletion, depreciation and amortization [2]	**$**	**4,810**	$	4,185	$	3,950
$/BOE [3]	**$**	**13.07**	$	12.92	$	12.27

(1) During 2024, in connection with the Company's notice of withdrawal from Block 11B/12B in South Africa, the Company derecognized $62 million of exploration and evaluation assets through depletion, depreciation and amortization expense.

(2) This is a non-GAAP financial measure used to calculate depletion, depreciation and amortization, less the impact of charges that are not related to current period normal course depletion, depreciation and amortization expense such as asset recoverability charges that are not related to current period production. It may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements (depletion, depreciation and amortization expense), as an indication of the Company's performance.

(3) This is a non-GAAP ratio calculated as adjusted depletion, depreciation and amortization expense divided by sales volumes. For sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Adjusted depletion, depreciation and amortization expense for 2025 of $13.07 per BOE was comparable with $12.92 per BOE for 2024 (2023 – $12.27 per BOE).

International Matters – North Sea and Offshore Africa

Pre-tax recoverability charges of $1,777 million in 2025 reflect the acceleration of the Company's abandonment and decommissioning activities and revisions to cost estimates in the North Sea, together with strategic decisions to not pursue an extension of its Production Sharing Contract ("PSC") for the Espoir Field, Block CI-26, in Offshore Africa and to not pursue development of Kossipo in Offshore Africa.

In the North Sea, following a competitive tender for the Ninian South Platform, estimated abandonment costs were higher than originally budgeted. Accordingly, the Company updated its abandonment and decommissioning cost estimates for the Ninian Central and South Platforms and T-Block (Tiffany, Toni and Thelma fields). Additionally, based on current and forecasted economic conditions, including commodity prices and market egress, the Company determined that the T-Block assets were no longer economically viable. Cessation of production has been accelerated to the first quarter of 2027 and associated crude oil reserves were de-booked. As a result, the Company recognized a non-cash charge of $836 million (2024 – $21 million; 2023 – $113 million), comprised of a recoverability charge recognized in depletion, depreciation and amortization expense of $1,462 million (2024 – $160 million; 2023 – $436 million), net of deferred tax recoveries of $626 million (2024 – $139 million; 2023 – $323 million).

In Offshore Africa, the Company determined that it would not pursue an extension of its PSC for the Espoir Field, Block CI-26, and de-booked associated crude oil reserves. The Company is working with the Government of Côte d'Ivoire to facilitate the transition of operatorship in the second half of 2026. As a result, the Company recognized a non-cash recoverability charge of $269 million as at December 31, 2025. Additionally, the Company decided not to pursue development of Kossipo, and recognized a recoverability charge of $46 million related to the derecognition of its exploration and evaluation assets.

Estimates of asset retirement obligations and related tax recoveries remain subject to revision as abandonment activities progress. Recoverability charges are recognized in depletion, depreciation and amortization expense.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		2025		2024		2023
North America	$	221	$	231	$	234
North Sea		64		65		46
Offshore Africa		9		9		8
Asset retirement obligation accretion	$	294	$	305	$	288
$/BOE [1]	$	0.80	$	0.94	$	0.89

(1) Calculated as asset retirement obligation accretion divided by sales volumes. For sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Asset retirement obligation accretion expense for 2025 of $0.80 per BOE decreased 15% from $0.94 per BOE for 2024 (2023 – $0.89 per BOE). The decrease in asset retirement obligation accretion expense per BOE for 2025 from 2024 reflected the impact of changes in discount rates at December 31, 2024, combined with higher sales volumes in 2025, partially offset by revisions in cost and timing estimates at December 31, 2024, North America acquisitions completed during 2025, and North Sea cost and timing estimate revisions during 2025.

Oil Sands Mining and Upgrading

OPERATING HIGHLIGHTS

The Company continues to focus on safe, reliable, and efficient operations, leveraging its technical expertise across the Horizon and AOSP sites. Record SCO production averaged 565,102 bbl/d in 2025, reflecting the acquisition completed in December 2024, combined with strong utilization. Additionally, the Company successfully completed the AOSP asset swap with Shell during the fourth quarter of 2025.

REALIZED PRODUCT PRICES, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

($/bbl)		2025		2024		2023
Realized SCO sales price [1]	$	86.41	$	98.03	$	100.06
Bitumen value for royalty purposes [2]	$	66.23	$	72.68	$	65.43
Bitumen royalties [3]	$	13.84	$	17.23	$	14.43
Transportation [4]	$	3.31	$	2.91	$	1.89

(1) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(2) Calculated as the annual average of the bitumen methodology price.

(3) Calculated as royalties divided by sales volumes.

(4) Calculated as transportation expense divided by sales volumes.

The realized SCO sales price averaged $86.41 per bbl for 2025, a decrease of 12% from $98.03 per bbl for 2024 (2023 – $100.06 per bbl). The decrease in realized SCO sales price per bbl for 2025 from 2024 primarily reflected lower WTI benchmark pricing.

Bitumen royalties averaged $13.84 per bbl for 2025, a decrease from $17.23 per bbl for 2024 (2023 – $14.43 per bbl) primarily reflecting the decrease in average bitumen value for royalty purposes and the impact of royalty true-ups.

Transportation expense averaged $3.31 per bbl for 2025, an increase of 14% from $2.91 per bbl for 2024 (2023 – $1.89 per bbl). The increase in transportation expense per bbl for 2025 from 2024 primarily reflected higher volumes shipped on the TMX pipeline in 2025.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production expense disclosed in note 21 to the Company's audited consolidated financial statements.

($ millions)		**2025**		2024		2023
Production expense, excluding natural gas costs	**$**	**4,543**	$	3,801	$	3,794
Natural gas costs		**150**		120		195
Production expense	**$**	**4,693**	$	3,921	$	3,989

($/bbl)		**2025**		2024		2023
Production expense, excluding natural gas costs [1]	**$**	**21.94**	$	22.18	$	23.13
Natural gas costs [2]		**0.72**		0.70		1.19
Production expense [3]	**$**	**22.66**	$	22.88	$	24.32
Sales volumes (bbl/d)		**567,335**		468,280		449,282

(1) Calculated as production expense, excluding natural gas costs, divided by sales volumes.

(2) Calculated as natural gas costs divided by sales volumes.

(3) Calculated as production expense divided by sales volumes.

Production expense for 2025 of $22.66 per bbl was comparable with $22.88 per bbl for 2024 (2023 – $24.32 per bbl).

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)		**2025**		2024		2023
Depletion, depreciation and amortization	**$**	**2,780**	$	2,258	$	2,011
$/bbl [1]	**$**	**13.42**	$	13.17	$	12.26

(1) Calculated as depletion, depreciation and amortization divided by sales volumes.

Depletion, depreciation and amortization expense for 2025 of $13.42 per bbl was comparable with $13.17 per bbl for 2024 (2023 – $12.26 per bbl).

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)		**2025**		2024		2023
Asset retirement obligation accretion	**$**	**86**	$	84	$	78
$/bbl [1]	**$**	**0.42**	$	0.49	$	0.48

(1) Calculated as asset retirement obligation accretion divided by sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Asset retirement obligation accretion expense for 2025 of $0.42 per bbl decreased 14% from $0.49 per bbl for 2024 (2023 – $0.48 per bbl). The decrease in asset retirement obligation accretion expense per bbl for 2025 from 2024 primarily reflected the impact of higher sales volumes.

Midstream and Refining

($ millions)	2025	2024	2023
Product sales			
Midstream activities	**$ 91**	$ 82	$ 76
NWRP, refined product sales and other	**670**	813	926
Segmented revenue	**761**	895	1,002
Less:			
NWRP, refining toll	**262**	295	303
Midstream activities	**22**	20	29
Production expense	**284**	315	332
NWRP, feedstock costs	**503**	669	646
Transportation expenses	**42**	16	18
Depreciation	**17**	16	16
Segmented loss	**$ (85)**	$ (121)	$ (10)

The Company's Midstream and Refining assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose, and the Company's 50% equity investment in NWRP. Approximately 25% of the Company's crude oil production is transported through its fully owned and operated Pelican Lake and ECHO pipelines to Edmonton and Hardisty, Alberta, providing access to international export pipelines. Ownership of these midstream pipeline assets enables the Company to control transportation costs and generate third-party revenue.

NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 bbl/d. The refinery processes approximately 50,000 bbl/d of bitumen feedstock, including 12,500 bbl/d of bitumen feedstock for the Company (25% toll payer) and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058. Sales of diesel and other refined products and associated refining tolls are recognized in the Midstream and Refining segment. Production of ultra-low sulphur diesel and other refined products for 2025 averaged 68,139 BOE/d (17,035 BOE/d to the Company) (2024 – 76,664 BOE/d; 19,166 BOE/d to the Company; 2023 – 81,525 BOE/d; 20,381 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at December 31, 2025, NWRP had $1,583 million (December 31, 2024 – $1,459 million) outstanding under its unsecured commercial paper program. NWRP has a $1,900 million syndicated credit facility that reserves capacity for amounts outstanding under its commercial paper program and for a debt service reserve equal to six months of anticipated facility interest and fees. As at December 31, 2025, the facility was undrawn.

During 2025, NWRP repaid and cancelled $250 million of the non-revolving portion of the syndicated credit facility.

During 2024, NWRP amended its syndicated credit facility to extend the revolving portion originally maturing June 2025 to June 2027, and reduce the authorized limit on the revolving portion by $275 million to $1,900 million. In 2024, NWRP repaid $657 million on its non-revolving facility, and reduced the authorized limit to $250 million.

As at December 31, 2025, NWRP had $8,750 million in long-term notes outstanding (December 31, 2024 – $8,750 million).

During 2024, NWRP repaid $500 million of 3.20% series A bonds. Additionally, in 2024 NWRP issued $700 million of 4.85% series P bonds due June 2034 and $600 million of 5.08% series Q bonds due June 2054.

NWRP also has short-term borrowings under a $300 million syndicated credit facility ("demand operating facility") (December 31, 2024 – $300 million). As at December 31, 2025, NWRP had borrowings of $50 million under the demand operating facility (December 31, 2024 – $103 million).

As at December 31, 2025, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $496 million (2024 – $509 million). The Company's recovery of unrecognized equity losses from NWRP for 2025 was $13 million (2024 – recovery of unrecognized equity losses of $46 million; 2023 – unrecognized equity loss of $4 million).

Corporate and Other

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)		2025		2024		2023
Administration expense	$	**615**	$	503	$	452
$/BOE [1]	$	**1.07**	$	1.02	$	0.93
Sales volumes (BOE/d) [2]		**1,575,845**		1,353,166		1,331,092

(1) Calculated as administration expense divided by sales volumes.

(2) Total Company sales volumes.

Administration expense for 2025 of $1.07 per BOE increased 5% from $1.02 per BOE for 2024 (2023 – $0.93 per BOE). Administration expense per BOE increased from 2024 primarily reflecting higher personnel costs, including incremental costs from recent acquisitions.

SHARE-BASED COMPENSATION

($ millions)		2025		2024		2023
Share-based compensation expense	$	**180**	$	279	$	491

The Company's Stock Option Plan provides employees with the right to receive common shares or a cash payment in exchange for stock options surrendered. The Performance Share Unit ("PSU") Plan provides certain executive employees of the Company with the right to receive a cash payment; the amount of which is determined with reference to the value of the Company's shares, by individual employee performance, and the extent to which certain other performance measures are met.

The Company recognized $180 million of share-based compensation expense for 2025 prim arily as a result of changes in the Company's share price, the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, and the impact of vested stock options exercised or surrendered during the period. An expense of $30 million related to PSUs granted to certain executive employees was included in the share-based compensation expense for 2025 (2024 – $77 million expense; 2023 – $70 million expense).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except effective interest rate)		2025		2024		2023
Interest and other financing expense	$	**834**	$	592	$	636
Less: Interest (income) and other expense [1]		**(205)**		(81)		(55)
Interest expense on long-term debt and lease liabilities [1]	$	**1,039**	$	673	$	691
Average current and long-term debt [2]	$	**18,401**	$	11,895	$	12,749
Average lease liabilities [2]		**1,570**		1,509		1,500
Average long-term debt and lease liabilities [2]	$	**19,971**	$	13,404	$	14,249
Average effective interest rate [3] [4]		**5.1%**		4.9%		4.8%
Interest and other financing expense ($/BOE) [5]	$	**1.45**	$	1.20	$	1.31
Sales volumes (BOE/d) [6]		**1,575,845**		1,353,166		1,331,092

(1) Item is a component of interest and other financing expense.

(2) The average of current and long-term debt and lease liabilities outstanding during the respective year.

(3) This is a non-GAAP ratio and may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the Company's audited consolidated financial statements, as applicable, as an indication of the Company's performance.

(4) Calculated as the average interest expense on long-term debt and lease liabilities divided by the average long-term debt and lease liabilities balance for the respective year. The Company presents its average effective interest rate for financial statement users to evaluate the Company's average cost of debt borrowings.

(5) Calculated as interest and other financing expense divided by sales volumes.

(6) Total Company sales volumes.

Interest and other financing expense for 2025 increased 21% to $1.45 per BOE from $1.20 per BOE for 2024 (2023 – $1.31 per BOE). The increase in interest and other financing expense per BOE for 2025 from 2024 primarily reflected higher average debt levels, partially offset by higher sales volumes.

The Company's average effective interest rate of 5.1% for 2025 increased from 4.9% for 2024 primarily reflecting higher average long-term debt levels held in 2025.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, interest rate, and foreign currency exposures. These derivative financial instruments are not intended for trading or speculative purposes.

($ millions)		**2025**		2024		2023
Foreign currency forward contracts	**$**	**(107)**	$	155	$	(17)
Foreign currency put options [1]		**23**		—		—
Natural gas financial instruments [2] [3] [4] [5]		**(5)**		13		3
Net realized (gain) loss		**(89)**		168		(14)
Foreign currency forward contracts		**—**		15		(9)
Natural gas financial instruments [2] [3] [4] [5]		**14**		(6)		21
Natural gas embedded derivative [6]		**57**		—		—
Net unrealized loss		**71**		9		12
Net (gain) loss	**$**	**(18)**	$	177	$	(2)

(1) During 2025, the Company periodically entered into foreign currency put options contracts. Further details are disclosed in note 18 to the Company's audited consolidated financial statements.

(2) In 2025, the Company entered into fixed price financial contracts to buy 12,500 MMBtu/d of natural gas at US$1.30 AECO for the period of August to December 2025, and 25,000 MMBtu/d of natural gas at US$2.16 AECO for the period of January to December 2026.

(3) In 2024, the Company entered into fixed price financial contracts to buy 12,500 MMBtu/d of natural gas at US$1.47 AECO, and 25,000 MMBtu/d of natural gas at US$1.82 AECO for the period of January to December 2025.

(4) In 2023, the Company entered into fixed price financial contracts to buy 50,000 MMBtu/d of natural gas at US$1.82 AECO for the period of January to December 2024.

(5) Certain commodity financial instruments were assumed in the acquisition of Painted Pony Energy Ltd. in 2020.

(6) In 2025, the Company entered into a long-term natural gas supply agreement containing an embedded derivative. Further details are disclosed in note 18 to the Company's audited consolidated financial statements.

During 2025, the Company recorded a net realized risk management gain of $89 million primarily related to the settlement of foreign currency forward contracts.

The Company recorded a net unrealized loss of $71 million ($55 million after tax of $16 million) on its risk management activities for 2025 (2024 – $9 million unrealized loss ($10 million after tax of $1 million); 2023 – $12 million unrealized loss ($7 million after tax of $5 million)).

Further details related to outstanding derivative financial instruments as at December 31, 2025 are disclosed in note 18 to the Company's audited consolidated financial statements.

FOREIGN EXCHANGE

($ millions)		**2025**		2024		2023
Net realized loss (gain)	**$**	**108**	$	67	$	(19)
Net unrealized (gain) loss		**(870)**		888		(260)
Net (gain) loss [1]	**$**	**(762)**	$	955	$	(279)

(1) Amounts are reported net of derivative financial instruments designated as cash flow hedges.

The net realized foreign exchange loss for 2025 was primarily related to exchange rate fluctuations on the settlement of US dollar debt, and on the settlement of working capital items denominated in US dollars. The net unrealized foreign exchange gain for 2025 was primarily related to the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at December 31, 2025 was US$ 0.7292 (December 31, 2024 – US$0.6942; December 31, 2023 – US$0.7573).

INCOME TAXES

($ millions, except effective tax rates)		2025		2024		2023
North America [1]	$	**2,193**	$	1,654	$	1,853
North Sea		**(124)**		(41)		(6)
Offshore Africa		**16**		57		73
Current PRT – North Sea		**(184)**		(134)		(58)
Other taxes		**10**		(5)		17
Current income tax		**1,911**		1,531		1,879
Deferred corporate income tax		**887**		520		267
Deferred PRT – North Sea		**(377)**		(98)		(214)
Deferred income tax		**510**		422		53
Income tax	$	**2,421**	$	1,953	$	1,932
Earnings before taxes	$	**13,241**	$	8,059	$	10,165
Effective tax rate on net earnings [2]		**18%**		24%		19%

($ millions, except effective tax rates)		2025		2024		2023
Income tax	$	**2,421**	$	1,953	$	1,932
Tax effect on non-operating items [3]		**(481)**		175		345
Current PRT – North Sea		**184**		134		58
Deferred PRT – North Sea		**(84)**		9		9
Other taxes		**(10)**		5		(17)
Effective tax on adjusted net earnings	$	**2,030**	$	2,276	$	2,327
Adjusted net earnings from operations [4]	$	**7,444**	$	7,414	$	8,533
Adjusted net earnings from operations, before taxes	$	**9,474**	$	9,690	$	10,860
Effective tax rate on adjusted net earnings from operations [5] [6]		**21%**		23%		21%

(1) Includes North America Exploration and Production, Oil Sands Mining and Upgrading, and Midstream and Refining segments.

(2) Calculated as total of current and deferred income tax divided by earnings before taxes.

(3) Includes the net income tax effect on PSUs, certain stock options, unrealized risk management, gain on disposition and remeasurement, and recoverability charges related to the North Sea and Offshore Africa.

(4) Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(5) This is a non-GAAP ratio and may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the Company's audited consolidated financial statements, as applicable, as an indication of the Company's performance.

(6) Calculated as effective tax on adjusted net earnings divided by adjusted net earnings from operations, before taxes. The Company presents its effective tax rate on adjusted net earnings from operations for financial statement users to evaluate the Company's effective tax rate on its core business activities.

The effective tax rate on net earnings and adjusted net earnings from operations for 2025 and the comparable years included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings.

Deferred corporate income tax in North America for 2025 included the deferred tax impacts of the gain on disposition and remeasurement associated with the AOSP asset swap.

The current and deferred corporate income tax and the current and deferred PRT in the North Sea included the impact of carrybacks of abandonment expenditures related to the decommissioning activities in the North Sea. Deferred PRT and income taxes also reflected the impact of the recoverability charges recognized in depletion, depreciation and amortization expense.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's reported results of operations, financial position or liquidity.

During 2025, the Company filed Scientific Research and Experimental Development claims of approximately $240 million (2024 – $273 million; 2023 – $380 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

Net Capital Expenditures [1] [2]

($ millions)	2025	2024	2023
EXPLORATION AND PRODUCTION			
Exploration and Evaluation Assets			
Net expenditures	**$ 46**	$ 82	$ 47
Net property acquisitions (dispositions) [3]	**69**	330	(3)
Total Exploration and Evaluation Assets	**115**	412	44
Property, Plant and Equipment			
Net property acquisitions [3]	**1,015**	2,642	24
Well drilling, completion and equipping	**2,107**	1,832	1,579
Production and related facilities	**1,560**	1,336	1,267
Other	**50**	53	61
Total Property, Plant and Equipment	**4,732**	5,863	2,931
Total Exploration and Production	**4,847**	6,275	2,975
OIL SANDS MINING AND UPGRADING			
Project costs	**319**	306	348
Sustaining capital	**1,274**	1,466	1,347
Turnaround costs	**241**	153	189
Net property acquisitions [3]	**(212)**	6,173	5
Other	**10**	6	5
Total Oil Sands Mining and Upgrading	**1,632**	8,104	1,894
Midstream and Refining	**8**	11	10
Head office	**92**	41	30
Net capital expenditures	**$ 6,579**	$ 14,431	$ 4,909
Abandonment expenditures	**$ 771**	$ 646	$ 509
By Segment			
North America	**$ 4,364**	$ 6,033	$ 2,770
North Sea	**16**	39	33
Offshore Africa	**467**	203	172
Oil Sands Mining and Upgrading	**1,632**	8,104	1,894
Midstream and Refining	**8**	11	10
Head office	**92**	41	30
Net capital expenditures	**$ 6,579**	$ 14,431	$ 4,909

(1) Net capital expenditures exclude the impact of lease assets and fair value adjustments.

(2) Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(3) Includes cash consideration paid of $320 million for exploration and evaluation assets and $2,553 million for property, plant and equipment within the North America Exploration and Production segment, and $6,175 million for property, plant and equipment within the Oil Sands Mining and Upgrading segment acquired from Chevron in 2024. Includes cash acquired and received as net consideration of $212 million related to the AOSP asset swap within the Oil Sands Mining and Upgrading segment in 2025.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production expenses.

Net capital expenditures for 2025 were $6,579 million compared with $14,431 million for 2024. In addition, the Company reported abandonment expenditures of $771 million for the year ended December 31, 2025 compared with $646 million for the year ended December 31, 2024.

CAPITAL SPENDING

On December 16, 2025, the Company announced its 2026 operating capital budget [(1)] targeted at approximately $6,300 million. With this capital, the Company is targeting production growth in 2026 of approximately 3% from 2025, as it invests in short and medium-term production, while commencing front-end engineering and design on potential additional medium and long-term value creation opportunities. In addition, the Company targets approximately $125 million of capital related to carbon capture projects. The Company targets $993 million in abandonment expenditures for 2026. Subsequent to December 31, 2025, the Company revised its operating capital forecast to $5,990 million and increased its production guidance to between 1,615,000 BOE/d and 1,665,000 BOE/d.

Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns, and the balancing of project risks and time horizons. The 2026 capital budget constitutes forward-looking statements and is based on net capital expenditures (Non-GAAP Financial Measure). Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

In February 2026, subsequent to year end, the Company acquired certain producing and non-producing crude oil and NGLs, and natural gas assets in the Peace River area in the North America Exploration and Production segment for cash consideration of approximately $765 million, subject to final closing adjustments. Net assets acquired primarily include exploration and evaluation assets and property, plant and equipment. The Company also assumed associated asset retirement obligations. The 2026 capital budget did not include capital related to this acquisition.

DRILLING ACTIVITY (1) (2)

(number of net wells)	**2025**	2024	2023
Net successful crude oil wells (3)	**358**	307	221
Net successful natural gas wells	**78**	78	61
Dry wells	**2**	2	2
Total	**438**	387	284
Success rate	**99%**	99%	99%

(1) Includes drilling activity for North America and International segments.

(2) Excludes stratigraphic and service wells.

(3) Includes bitumen wells.

North America

During 2025, the Company drilled 78 net natural gas wells, 198 net primary heavy crude oil wells, 16 net Pelican Lake heavy crude oil wells, 78 net thermal bitumen wells, and 68 net light crude oil wells.

Liquidity and Capital Resources

($ millions, except ratios)	**2025**	2024	2023
Adjusted working capital (1)	**$ 42**	$ 174	$ 712
Long-term debt, net (2)	**$ 15,944**	$ 18,688	$ 9,922
Shareholders' equity	**$ 44,366**	$ 39,468	$ 39,832
Debt to book capitalization (2)	**26%**	32%	20%
After-tax return on average capital employed (3)	**20%**	13%	17%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Capital Management Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(3) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

As at December 31, 2025, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities, and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt are dependent on factors discussed in the 'Business Environment and Outlook' section and in the 'Risks and Uncertainties' section of this MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings, as determined by independent rating agencies and market conditions. The Company continues to believe its internally generated cash flows from operating activities, supported by its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short-, medium-, and long-term and support its growth strategy.

(1) Forward-looking non-GAAP Financial Measure. The operating capital budget is based on net capital expenditures (Non-GAAP Financial Measure). Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A for more details on net capital expenditures.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers, and joint venture partners on a regular basis and, where appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;
- Actively managing the allocation of capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments, and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
  - During 2025, the Company extended its $500 million revolving credit facility originally maturing February 2026 to June 2027. During 2024, the Company extended its $500 million revolving credit facility from February 2025 to February 2026. During 2023, the Company extended its $500 million revolving credit facility from February 2024 to February 2025.
  - During 2025, the Company increased its $2,425 million revolving syndicated facility to $2,565 million, and extended $2,425 million originally due June 2027 to June 2029. The remaining $140 million outstanding under this facility will mature in June 2027. Each of the revolving credit facilities are extendible annually at the mutual agreement of the Company and lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.
  - During 2024, the Company extended its $2,425 million revolving syndicated credit facility originally maturing June 2025 to June 2028.
  - During 2024 and in connection with the acquisition of Chevron's assets, the Company entered into a $4,000 million non-revolving term credit facility maturing December 2027.
  - Borrowings under the Company's credit facilities may be made by way of pricing referenced to CORRA, SOFR, US base rate or Canadian prime rate.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - During 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
  - During 2025, the Company issued $550 million of 3.30% medium-term notes due December 2028, $550 million of 3.75% medium-term notes due February 2031, and $550 million of 4.55% medium-term notes due February 2036. After issuing these securities, the Company had $1,350 million remaining on its base shelf prospectus.
  - During 2024, the Company repaid $320 million of 3.55% medium-term notes.
  - During 2024, the Company issued $500 million of 4.15% medium-term notes due December 2031.
  - During 2025, the Company repaid US$600 million of 3.90% US dollar debt securities due February 2025, and US$600 million of 2.05% US dollar debt securities due July 2025.
  - During 2024, the Company repaid US$500 million of 3.80% US dollar debt securities.
  - During 2024, the Company issued US$750 million of 5.00% notes due December 2029 and US$750 million of 5.40% notes due December 2034.
  - During 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$4,500 million of debt securities in the United States, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
  - During 2025, the Company filed a prospectus supplement to the base shelf prospectus. Under the base shelf prospectus, the Company completed the exchange of US$747 million of the outstanding restricted 5.00% US dollar debt securities due December 2029 and US$750 million of the outstanding restricted 5.40% US dollar debt securities due December 2034. The exchanged notes were not subject to transfer restrictions and did not impact the Company's level of indebtedness. After the exchange of these securities, the Company had US$3,003 million remaining on its base shelf prospectus.

As at December 31, 2025, the Company had undrawn bank credit facilities of $5,668 million, and a fully drawn non-revolving term credit facility of $4,000 million. Including cash and cash equivalents, the Company had approximately $6,341 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit.

Long-term debt, net was $15,944 million as at December 31, 2025, resulting in a debt to book capitalization ratio of 26% (December 31, 2024 – 32%; December 31, 2023 – 20%); this ratio was within the 25% to 45% internal range utilized by management. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2025, the Company was in compliance with this covenant.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt as at December 31, 2025 are discussed in note 10 to the Company's audited consolidated financial statements.

During 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. for $25.65 per common share with net proceeds at close, after fees and expenses, of $575 million.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of commodity put options is in addition to the above parameters. Further details related to the Company's commodity derivative financial instruments outstanding as at December 31, 2025 are discussed in note 18 to the Company's audited consolidated financial statements.

As at December 31, 2025, the maturity dates of certain financial liabilities, including long-term debt and other long-term liabilities and related interest payments, were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt [1]	$ 441	$ 5,637	$ 2,489	$ 8,140
Other long-term liabilities [2]	$ 381	$ 268	$ 659	$ 1,863
Interest and other financing expense [3]	$ 971	$ 910	$ 1,860	$ 3,678

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, $373 million; one to less than two years, $268 million; two to less than five years, $654 million; and thereafter, $1,811 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2025.

SHARE CAPITAL

As at December 31, 2025, there were 2,081,578,000 common shares outstanding (December 31, 2024 – 2,102,996,000 common shares) and 54,734,000 stock options outstanding (December 31, 2024 – 50,806,000 stock options). As at March 3, 2026, the Company had 2,085,972,000 common shares outstanding and 57,252,000 stock options outstanding.

On March 4, 2026, the Board of Directors approved a 6% increase in the quarterly dividend to $0.625 per common share, beginning with the dividend payable on April 7, 2026.

On March 5, 2025, the Board of Directors approved a 4% increase in the quarterly dividend to $0.5875 per common share.

On October 7, 2024, the Board of Directors approved a 7% increase in the quarterly dividend to $0.5625 per common share. On February 28, 2024, the Board of Directors approved a 5% increase in the quarterly dividend to $0.525[1] per common share.

On November 1, 2023, the Board of Directors approved an 11% increase in the quarterly dividend to $0.50 [1] per common share. On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.45[1] per common share.

The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split. Further details are disclosed in the 'Advisory' section of this MD&A and in note 1 to the Company's audited consolidated financial statements.

On March 10, 2025, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 178,738,237 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2025 and ending March 12, 2026.

For the year ended December 31, 2025, the Company purchased 33,480,000 common shares at a weighted average price of $43.28 per common share for a total cost, including tax, of $1,467 million. Retained earnings were reduced by $1,287 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2025, up to and including March 3, 2026, the Company purchased 3,300,000 common shares at a weighted average price of $51.12 per common share for a total cost, including tax, of $169 million.

On March 4, 2026, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of Normal Course Issuer Bid, up to 10% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares. Subject to acceptance of the Notice of Intention by the TSX, and applicable securities law, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

Commitments and Contingencies

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2025:

($ millions)	2026	2027	2028	2029	2030	Thereafter
Product transportation, purchases, and processing [1][2][3][4]	$ 2,241	$ 2,223	$ 2,065	$ 1,912	$ 1,758	$ 18,025
North West Redwater Partnership service toll [5]	$ 116	$ 95	$ 96	$ 95	$ 95	$ 3,878
Offshore vessels and equipment	$ 99	$ —	$ —	$ —	$ —	$ —
Field equipment and power [4]	$ 50	$ 26	$ 26	$ 24	$ 24	$ 170
Other	$ 122	$ 50	$ 19	$ 18	$ 18	$ 177

(1) The Company's commitment for its 20-year product transportation agreement ending in 2044 on the TMX pipeline reflects interim tolls approved by the Canada Energy Regulator in 2023, and is subject to change pending the approval of final tolls.

(2) In 2025, in connection with the AOSP asset swap, the Company became the sole contracted shipper on the Corridor pipeline. Previously, the Company recognized a commitment associated with the pipeline, however, following the completion of the AOSP asset swap the contract has been recorded as a lease. Further details on the AOSP asset swap are disclosed in note 6 to the Company's audited consolidated financial statements.

(3) During 2024, the Company increased its total committed capacity on the TMX pipeline to 169,000 bbl/d, an incremental 75,000 bbl/d over the 20-year term.

(4) During 2024, the acquisition of Chevron's assets included approximately $1,292 million of product transportation and processing commitments and approximately $75 million of field equipment and power commitments.

(5) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $1,792 million of interest payable over the 40-year tolling period, ending in 2058.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement, and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

Reserves

For the years ended December 31, 2025 and 2024, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's total proved and total proved plus probable reserves. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The following are reconciliation tables of the Company gross total proved and total proved plus probable reserves using forecast prices and costs as at the effective date of December 31, 2025:

Total Proved	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Thermal Bitumen (MMbbl)	Mining Bitumen[2] (MMbbl)	Synthetic Crude Oil[2] (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2024 [1]	252	219	255	3,312	—	7,663	16,904	713	15,231
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	16	12	—	66	—	—	113	8	121
Infill Drilling	2	17	1	9	—	—	191	36	97
Improved Recovery	—	1	3	—	—	2	—	—	6
Acquisitions	68	—	—	—	427	—	1,153	74	760
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(4)	(4)	(3)	—	—	—	(99)	(4)	(32)
Technical Revisions	1	15	2	43	426	(328)	674	28	300
Production	(26)	(32)	(16)	(100)	(4)	(202)	(930)	(38)	(573)
December 31, 2025 [1]	**309**	**228**	**243**	**3,330**	**849**	**7,134**	**18,006**	**817**	**15,910**

Total Proved Plus Probable	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Thermal Bitumen (MMbbl)	Mining Bitumen[2] (MMbbl)	Synthetic Crude Oil[2] (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2024 [1]	346	318	360	5,190	—	8,255	27,156	1,116	20,110
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	22	20	—	89	—	—	167	12	171
Infill Drilling	2	26	3	11	—	—	325	54	149
Improved Recovery	—	1	4	—	—	2	—	—	7
Acquisitions	99	—	—	—	450	—	1,469	95	888
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(5)	(5)	(2)	—	—	—	(99)	(4)	(32)
Technical Revisions	(11)	5	—	(15)	449	(367)	(114)	(14)	29
Production	(26)	(32)	(16)	(100)	(4)	(202)	(930)	(38)	(573)
December 31, 2025 [1]	**427**	**333**	**349**	**5,175**	**895**	**7,688**	**27,974**	**1,221**	**20,750**

(1) Information in the reserves data tables may not add due to rounding. BOE values as presented may not calculate due to rounding.

(2) Except as disaggregated in the 'Reserves' section of this MD&A, all references to Synthetic Crude Oil also include Mining Bitumen within the product streams produced by Horizon, AOSP mines, and the Scotford Upgrader in this MD&A.

At December 31, 2025, the Company's total proved crude oil, thermal bitumen, mining bitumen, SCO, and NGLs reserves were 12,909 MMbbl, and total proved plus probable crude oil, thermal bitumen, mining bitumen, SCO, and NGLs reserves were 16,088 MMbbl. Total proved reserves additions and revisions replaced 218% of 2025 production. Additions to total proved reserves resulting from exploration and development activities, acquisitions, dispositions, and future offset additions amounted to 741 MMbbl, and additions to total proved plus probable reserves amounted to 889 MMbbl. Net positive revisions amounted to 173 MMbbl for total proved reserves and 33 MMbbl for total proved plus probable reserves, primarily due to technical revisions.

At December 31, 2025, the total proved natural gas reserves were 18,006 Bcf, and total proved plus probable natural gas reserves were 27,974 Bcf. Total proved reserves additions and revisions replaced 218% of 2025 production. Additions to total proved reserves resulting from exploration and development activities, acquisitions, dispositions, and future offset additions

amounted to 1,457 Bcf, and additions to total proved plus probable reserves amounted to 1,961 Bcf. Net positive revisions amounted to 574 Bcf for total proved reserves, primarily due to technical revisions. Net negative revisions amounted to 213 Bcf for total proved plus probable reserves, due to technical revisions and decreasing commodity prices.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves. Additional reserves information is annually disclosed in the AIF.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities – Oil and Gas" in the Company's annual report on Form 40-F filed with the SEC and in the 'Supplementary Oil and Gas Information' section of the Company's annual report.

Risks and Uncertainties

The Company is exposed to various operational risks inherent in the exploration, development, production and marketing of crude oil and NGLs and natural gas and the mining, extracting and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following:

- Volatility in the prevailing prices of crude oil and NGLs, natural gas and refined products;
- The ability to find, produce, and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserves revisions due to economic and technical factors. Reserves revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserves estimates;
- Regulatory risk associated with project or facility expansions, or for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting and upgrading the Company's bitumen products;
- Timing and success of integrating the business and operations of acquired companies and assets;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to the effect of fluctuating exchange rates on the Company's US dollar denominated debt and revenue from sales predominantly based on US dollar denominated benchmarks;
- Environmental risk associated with exploration and development activities, including associated GHG emissions;
- Future legislative and regulatory developments related to environmental regulation, including but not limited to GHG compliance costs and reduction targets, and emissions caps;
- The timing and pace of change to a low carbon economy is uncertain and the ability to access insurance and capital may be adversely affected in the event that financial institutions, investors, insurers, rating agencies and/or lenders adopt more restrictive decarbonisation policies;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations, including but not limited to restrictions on production and the certainty and timelines for regulatory approval processes;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- International trade risk with key trading partners, including the imposition of tariffs or other trade measures on the Company's products or goods and services used by the Company in its supply chain, including the imposition of countermeasures by the government of Canada, the duration and extent of which may be uncertain;
- Changing royalty regimes;
- The ability to secure adequate transportation for products, which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors;
- The access to markets for the Company's products;

- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's data security, intellectual property and operations, and/or result in a material privacy breach;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, droughts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- Epidemics or pandemics have the potential to disrupt the Company's operations, projects and financial condition through the disruption of the local or global supply chain and transportation services, or the loss of Company manpower resulting from quarantines (as was the case with the COVID-19 pandemic). Depending on the severity, a large scale epidemic or pandemic could impact international demand for commodities and have a corresponding impact on the prices realized by the Company, which could have a material adverse effect on the Company's financial condition;
- Liquidity risk related to the Company's ability to fulfill financial obligations as they become due or ability to liquidate assets in a timely manner at a reasonable price; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to seek to mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades and NGLs. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company seeks to manage these risks by monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default. Derivative financial instruments are periodically utilized to help ensure targets are met and to manage commodity price, foreign currency, and interest rate exposures. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company seeks to manage this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper, and access to debt capital markets, to meet obligations as they become due. The Company has implemented cyber security protocols and procedures designed to reduce the risk of failure or a significant breach of the Company's information technology systems and related data and control systems.

The Company has safety, asset integrity and environmental management systems to recover and process crude oil and natural gas resources safely and efficiently while being committed to environmental stewardship.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional details regarding the Company's risks and uncertainties, refer to the Company's AIF for the year ended December 31, 2025.

Environment

The Company has a Corporate Statement on Environmental Management which affirms that environmental stewardship is a fundamental value of the Company. As part of the Company's commitment to environmental stewardship, the Company includes and evaluates environmental, social, economic, and health considerations in new project designs and in operations, where appropriate. The Company invests in people, facilities and infrastructure, as well as new and proven technologies (including technologies designed to improve environmental performance), to recover and process crude oil and natural gas resources efficiently and in an environmentally responsible manner. When working with local communities, the Company considers the interests and values of the people using the land in proximity to its operations and, where appropriate, adapts projects to recognize or accommodate these concerns.

The Company has processes in place and is committed to complying with all existing environmental standards and regulations and has included appropriate amounts in its capital budget to continue to meet current environmental protection requirements; however there are no assurances that the effect of future environmental laws and regulations will not have a material effect on the Company's business, financial condition and results of operations. The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation compliance, particularly in North America and the North Sea. Existing and expected legislation and regulations may require the Company to address and take steps to mitigate the effect of its activities on the environment. To address some of these concerns, the Company's environmental risk management strategy includes working constructively with legislators and regulators on any new or revised policies, legislation or regulations to

reflect a balanced approach to sustainable development. However, increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings.

The environmental risk management strategies employed by the Company are based upon an Environmental Management Plan (the "Plan") that incorporates targets and measurements against which the Company's environmental performance is measured, all of which is presented to, and reviewed by, the Board of Directors quarterly.

As part of the Company's environmental stewardship and risk management, the Company engages in research (often through collaborative efforts with industry partners, governments and research institutions) designed to develop, assess and implement new or improved technologies and innovative practices that are intended to improve environmental performance.

The Plan, in conjunction with the Company's operating practices and guidelines, has been adopted with the intention of reducing the environmental impact of operations while meeting: regulatory requirements; regional management frameworks for air quality and emissions, ground and surface water, and biodiversity; industry operating standards and guidelines, and internal corporate standards. Adequate and proper training of, and diligent execution by, the Company's operators and contractors is key to the effectiveness of the Company's environmental management programs and supports efforts to reduce the Company's environmental footprint. The Company, as part of this Plan, has implemented proactive programs that include:

- Implementation of various GHG emissions and methane reduction programs, and optimization programs that seek to improve efficiencies at the Company's facilities;
- Environmental planning to assess potential impacts by the Company's operations and implement avoidance strategies and mitigation programs that seek to maintain biodiversity for terrestrial and aquatic systems and high value ecosystems;
- Continued evaluation of new technologies designed to reduce environmental impacts from operations, including support for Canada's Oil Sands Innovation Alliance ("COSIA"), the innovation arm of Pathways, Petroleum Technology Alliance Canada ("PTAC") and other research institutions;
- Water management programs that are designed to improve recycle rates and reduce fresh water use;
- Groundwater monitoring for all thermal in situ and mine operations;
- Reclamation and decommissioning programs across the Company's operations. In North America, well abandonment and progressive reclamation of large contiguous areas of land supports biodiversity and functional wildlife habitats. In the Company's International operations, decommissioning activities continued at the Ninian Hub and stakeholder engagement was completed ahead of formally submitting the Ninian South Decommissioning Program for regulatory approval in December 2025;
- Tailings management in Oil Sands Mining intended to reduce fine tailings and promote progressive reclamation;
- Monitoring programs to assess changes to biodiversity, wildlife and fisheries in order to manage construction and operations impacts and to assess reclamation success;
- Participation in the joint Alberta / Federal government Oil Sands Monitoring Program which supports the regional monitoring of air, surface water, groundwater, wetlands, and biodiversity;
- An active spill prevention and management program;
- Support for regional air shed monitoring for emissions and their deposition; and
- An internal environmental management system for conformance audit and inspection programs of operating facilities.

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.9% (2024 – 4.8%; 2023 – 5.2%). For 2025, the Company's capital expenditures included $771 million for abandonment expenditures (2024 – $646 million; 2023 – $509 million). The Company's estimated discounted ARO at December 31, 2025 was as follows:

($ millions)		**2025**		2024
Exploration and Production				
North America	**$**	**4,937**	$	4,783
North Sea		**2,629**		1,724
Offshore Africa		**275**		197
Oil Sands Mining and Upgrading		**1,901**		1,902
Midstream and Refining		**1**		1
	$	**9,743**	$	8,607

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine sites, upgrading facilities and tailings, and offshore production platforms.

Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on estimates of current costs in accordance with present legislation, industry operating practice as well as the expected work scope and the timing of abandonment.

The Alberta Energy Regulator ("AER") established a Liability Management Framework, as part of its life-cycle management of oil and natural gas wells, facilities and pipelines, which imposes mandatory annual minimum spend requirements on licensees for the closure of inactive wells and related infrastructure. Under the framework, the AER assigns a licensee an annual minimum spend requirement for reclamation and abandonment activities to be completed based on a licensee's proportionate share of the provincial inventory of inactive wells and related infrastructure, among other factors. In Alberta, the mandatory minimum spend requirements are reviewed annually and have increased from 4% in 2022 to the current rate of 6.2% in 2025. The Government of Saskatchewan has a similar program in place (the Inactive Liability Reduction Program), which had a 6% minimum spend requirement in 2025. In British Columbia, the Dormancy and Shutdown Regulations also set out mandatory targets for decommissioning and restoring inactive wells and facilities. In addition to minimum spend requirements for abandonment and reclamation, each of the provincial regulators have the ability to require licensees to post financial security to secure a licensee's abandonment and reclamation obligations.

GREENHOUSE GAS AND OTHER EMISSIONS

The Company, through industry associations, is working with Canadian legislators and regulators as they develop and implement laws and regulations to properly reflect a balanced approach to sustainable development, such as programs to support industry investments in environmental performance improvement and emissions reduction. The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new and existing GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new and existing policies encourage technological innovation, energy efficiency, and targeted research and development while not impacting competitiveness.

Governments in jurisdictions where the Company operates have developed GHG regulations as part of their provincial, federal and international climate change commitments. The Company continuously monitors developments in the GHG regulatory environment in applicable jurisdictions to assess the cost impact of new and existing regulations on current and future operations and proposed projects under consideration.

Federal Carbon Policy and GHG Emissions Regulation

The federal government ratified the Paris Agreement, which included a commitment to reduce Canada's GHG emissions by 40 – 45% from 2005 levels by 2030. In December 2024, the federal government updated its commitment to extend the timing to achieve the national GHG emission reduction target to 2035. The federal regulations supporting the Paris Agreement mandate that the federal carbon price increase in annual increments of $15/tonne after 2022 to $170 per tonne by 2030. The federal Clean Fuel Regulations ("CFR"), which took effect on July 1, 2023, require reductions in the carbon intensity of gasoline and diesel fuels produced or sold in Canada. The federal Clean Electricity Regulations ("CER") came into effect on January 1, 2025, and establishes GHG emission limits for almost all fossil fuel-powered electricity generation units, beginning in 2035.

In addition to existing federal GHG regulations and the CFR, the federal government published draft regulations in 2024 that propose to cap emissions from the oil and gas sector through a national cap-and-trade system. This has not yet been implemented and is dependent on final agreements negotiated as part of the MOU (see below for further discussion). In 2025, new federal regulations were also released intended to control the release of volatile organic compounds ("VOCs") from petroleum refineries and upgraders; truck, rail, marine, and pipeline terminals; petrochemical facilities; bulk fuel facilities; and steel mills.

In November 2025, the federal and Alberta governments entered into the MOU which is intended to increase western Canada's energy production and establish Canada as an energy leader while reducing GHG emissions through innovative technologies and infrastructure programs. The MOU included the following:

- The federal government agreed not to implement an oil and gas emissions cap, contingent on the province of Alberta meeting certain commitments, one of which is related to the development of carbon capture infrastructure;
- The application of the CER in Alberta was suspended pending the finalization of a new carbon pricing agreement to be administered through Alberta's Technology Innovation and Emissions Reduction ("TIER") Regulation program, the details of which are to be negotiated by the parties on or before April 1, 2026; and
- A commitment by the parties to work collaboratively to design and implement a globally competitive, long-term carbon pricing scheme, carbon levy recycling protocols, and sector-specific stringency factors for large emitters in both the oil and gas and electricity sectors through Alberta's TIER system. Under this proposal, the TIER system will ramp up to a minimum effective credit price of $130/tonne. The parties are anticipated to conclude an agreement on industrial carbon pricing on or before April 1, 2026 in furtherance of this agreement.

Although the MOU appears supportive of Canada's energy sector, there are no assurances that the parties will reach final agreement on all of the necessary elements required to enable the MOU framework or that the environmental laws and regulations negotiated as part of the MOU will have a favourable impact on either the oil and gas industry in Alberta or the Company and may ultimately have a material adverse effect on the Company's business, financial condition and operations.

Provincial GHG Policy and Regulation

Industrial carbon pricing regulatory systems in all provinces are subject to periodic review by the federal government to assess the adequacy of the provincial systems against the federal Greenhouse Gas Pollution Pricing Act. To the extent a province's carbon pricing system does not meet the federal stringency requirements, the federal backstop regulations apply.

Alberta: In Alberta, the TIER sets the carbon pricing framework that applies to the Company's facilities with emissions greater than 100,000 t CO_2e/year, and certain facilities opted into the TIER system by the Company. In 2025, the carbon price in Alberta for emissions above the TIER regulated limits was $95/tonne. In May 2025, the Alberta government indefinitely capped the carbon price at $95/tonne, which may be subject to change following finalization of a new carbon pricing agreement with the federal government on or before April 1, 2026 (as stipulated in the MOU). Emissions from the non-operated Scotford Upgrader and the North West Redwater bitumen upgrader and refinery are also subject to TIER.

British Columbia: In 2025, the industrial carbon price in British Columbia under the province's output based price system was $95/tonne and increases by $15/tonne CO_2e annually until it reaches $170/tonne of CO_2e in 2030, in alignment with the federal carbon pricing schedule. In 2023, British Columbia announced its intention to implement a Net-Zero New Industry policy as well as an emissions cap for the oil and gas industry. This cap is intended to ensure that the province meets its emissions reduction target of 33-38% below 2007 emissions levels by 2030. In 2024, British Columbia announced that it would be introducing regulatory measures to backstop the federal carbon emissions cap, which were to apply in the event of gaps between federal and provincial targets and in the event that the federal emissions cap is not implemented or cancelled.

Saskatchewan: As part of its Prairie Resilience Plan, in 2018, the Saskatchewan government enacted the Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations, that apply to facilities emitting more than 25 kilotonnes of CO_2e annually. This regulation required the Company's North Tangleflags in situ heavy crude oil facility and the Senlac in situ heavy crude oil facility to meet reduction targets for GHG emissions commencing in 2020. This regulation also enables facilities that emit less than 25 kilotonnes of CO_2e annually to aggregate and opt-in to the Saskatchewan regulatory system as an alternative to the federal fuel charge. In April 2025, the province of Saskatchewan paused the application and collection of industrial carbon taxes. Since this would result in Saskatchewan not meeting the federal stringency requirement, the province may be subject to the federal backstop regulation if applied by the federal government in the future.

Manitoba: In the absence of provincial regulations for carbon pricing and GHG emissions, the federal output-based pricing system and carbon pricing schedule applies to Manitoba facilities with emissions greater than or equal to 50 kilotonnes of CO_2e annually. Facilities with emissions equal to or greater than 10 kilotonnes CO_2e annually can voluntarily opt-in to the system.

Methane Emissions Reduction Regulations

The federal government's methane regulation which came into effect on January 1, 2020 applies nationally unless provinces reach equivalency agreements with the federal government. The federal government originally had a commitment to reduce methane emissions from the oil and gas sector by 40-45% from the 2012 levels by 2025. In 2021, the federal government set a target to further reduce methane emissions to achieve at least a 75% reduction below 2012 levels by 2030. The provinces of British Columbia, Alberta and Saskatchewan have equivalency agreements in place with the federal government that allow the applicable provincial methane regulations to govern in these three western provinces. The federal methane regulation continues to apply in the province of Manitoba. Pursuant to the MOU entered into by the federal government and the government of Alberta in November 2025, the parties intend to enter into a new methane equivalency agreement on or before April 1, 2026. Once concluded, this new equivalency agreement will extend the target date to achieve the mandated 75% methane emissions reduction (relative to 2014 levels) to 2035. In December 2025, the final methane regulation ("Enhanced Methane Regulations") was enacted by the federal government, with phase-in of the regulatory requirements beginning January 1, 2028.

United Kingdom GHG Emissions Regulation

GHG emissions from the Company's UK operations are regulated under the UK Emissions Trading Scheme ("ETS") which was launched on January 1, 2021 and replaced the UK's participation in a comparable European Union ("EU") system. The UK scheme is aligned with the EU ETS rules and applies to energy intensive industries, the power generation sector and aviation.

Accounting Policies and Standards

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions, and judgements in the application of IFRS Accounting Standards that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in this MD&A and the audited consolidated financial statements for the year ended December 31, 2025.

A) Depletion, Depreciation and Amortization and Impairment

Exploration and evaluation ("E&E") costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. The judgements associated with the estimation of proved reserves are described below in 'Crude Oil and Natural Gas Reserves'.

An alternative acceptable accounting method for E&E costs under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, discount rates, income taxes, and the potential impact of climate related matters and in accordance with related government regulations. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Crude oil and natural gas properties in the Exploration and Production segments are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment discounted at rates currently ranging from 10% to 12% whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs a recoverability assessment related to the specific assets at the CGU level.

B) Crude Oil and Natural Gas Reserves

Reserves estimates, evaluated by the Company's Independent Qualified Reserves Evaluators, are based on estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations, and judgements, including the potential impact of climate related matters and in accordance with related government regulations. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of E&E and property, plant and equipment carrying amounts.

C) Asset Retirement Obligations

The Company is required to recognize a liability for ARO associated with its property, plant and equipment, including property, plant and equipment for which underlying reserves have been de-booked, and the carrying value of the asset has been fully depleted. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total

ARO amount, including the potential impact of climate related matters and in accordance with related government regulations. These individual assumptions may be subject to change.

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's weighted average credit-adjusted risk-free interest rate, which is currently 4.9%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

D) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted that are expected to apply when the asset or liability is recovered. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

E) Risk Management Activities

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, Canadian and United States foreign exchange rates and other volatility factors discounted to present value as appropriate. The carrying amount of a risk management liability is adjusted for the Company's own credit risk. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

F) Purchase Price Allocations

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions, and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties, derived from the present value of estimated future cash flows from the assets, together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation and amortization expense and impairment tests.

The Company has made various assumptions in determining the fair values of acquired assets and liabilities. The most significant assumptions and judgements relate to the estimation of the fair value of crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates crude oil and natural gas reserves. Reserves estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in 'Crude Oil and Natural Gas Reserves'. Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future production and development costs, to arrive at estimated future net revenues for the properties acquired.

G) Share-Based Compensation

The Company has made various assumptions in estimating the fair values of stock options granted including expected volatility, expected exercise timing, and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the estimated fair value of the liability.

H) Leases

Purchase, extension, and termination options are included in certain of the Company's leases to provide operational flexibility. To measure the lease liability, the Company uses judgement to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options

may have changed. The Company also uses estimates to determine its incremental borrowing costs if the interest rate implicit in the lease is not readily determinable.

l) Government Grants

The Company receives or is eligible for government grants including emissions credits. Government grants are recognized in net earnings when there is reasonable assurance that the Company will comply with the conditions attached to the grant and the grant will be received. Emissions performance and offset credits generated under the Alberta TIER regulation are initially recorded at fair value as determined by the prescribed Alberta TIER fund compliance rates in effect at the time the credits are recognized.

Control Environment

The Company's management, including the President and the Chief Financial Officer, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2025, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized, and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management, including the President and the Chief Financial Officer, also evaluated the effectiveness of internal control over financial reporting as at December 31, 2025, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2025 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems 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.

Non-GAAP and Other Financial Measures

This MD&A includes references to non-GAAP and other financial measures as defined in NI 52-112. These financial measures are used by the Company to evaluate its financial performance, financial position, and cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS Accounting Standards and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below.

ADJUSTED NET EARNINGS FROM OPERATIONS

Adjusted net earnings from operations is a non-GAAP financial measure that adjusts net earnings as presented in the Company's consolidated statements of earnings, for non-operating items, net of tax impacts. The Company considers adjusted net earnings from operations a key measure in evaluating its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. A reconciliation for adjusted net earnings from operations is presented below.

($ millions)	**2025**	2024	2023
Net earnings	**$ 10,820**	$ 6,106	$ 8,233
Share-based compensation, net of tax [1]	**166**	257	474
Unrealized risk management loss, net of tax [2]	**55**	10	7
Unrealized foreign exchange (gain) loss, net of tax [3]	**(870)**	888	(260)
Realized foreign exchange loss on financing activities, net of tax [4]	**54**	135	—
Gain from investment, net of tax [5]	**—**	(50)	(34)
Gain on acquisitions, disposition, and remeasurement, net of tax [6] [7]	**(3,925)**	—	—
Recoverability charges, net of tax [8] [9]	**1,144**	68	113
Non-operating items, net of tax	**(3,376)**	1,308	300
Adjusted net earnings from operations	**$ 7,444**	$ 7,414	$ 8,533

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU Plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets, and periodic changes in the fair value are recognized in net earnings. Pre-tax share-based compensation for 2025 was an expense of $180 million (2024 – $279 million expense; 2023 – $491 million expense).

(2) Derivative financial instruments are recognized at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than those amounts reflected in the Company's audited consolidated financial statements due to changes in prices of the underlying items hedged, primarily natural gas and foreign exchange. The pre-tax unrealized risk management loss for 2025 was $71 million (2024 – $9 million loss; 2023 – $12 million loss).

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates and are recognized in net earnings. Pre- and after-tax amounts for these unrealized foreign exchange gains and losses are the same.

(4) Realized foreign exchange losses associated with financing activities primarily result from the repayment of US dollar denominated debt and are recognized in net earnings Pre- and after-tax amounts for these realized foreign exchange losses are the same.

(5) The Company's investments have been accounted for at fair value through profit and loss and are measured each period with gains and losses recognized in net earnings. During 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. for $25.65 per common share with net proceeds at close, after fees and expenses, of $575 million. There is a $nil net tax impact on the sale as the Company has sufficient capital losses to offset the capital gain on the sale.

(6) During 2025, the Company acquired an interest in certain producing and non-producing crude oil and NGLs, and natural gas assets in the North America Exploration and Production segment, resulting in a pre- and after-tax gain on acquisition of $80 million representing the excess of the fair value of the net assets acquired compared to the total purchase consideration.

(7) During 2025, the Company completed the AOSP asset swap. As a result, the Company recognized a gain on acquisition, disposition, and remeasurement of $4,989 million ($3,845 after-tax) in net earnings. The transaction is discussed further in the 'Financial and Operational Highlights' section of this MD&A.

(8) During 2025, the Company recognized pre-tax non-cash recoverability ch arges of $1,462 million ($836 million after-tax) (2024 – $160 million ($21 million after-tax); 2023 – $436 million ($113 million after-tax)) in depletion, depreciation and amortization expense relating to the North Sea abandonment and decommissioning activities. The costs are included in capital and abandonment expenditures, consistent with the treatment of all abandonment related expenditures for the purpose of the Company's non-GAAP measures. Recoverability charges are discussed in the 'Adjusted Depletion, Depreciation and Amortization – Exploration and Production' section of this MD&A.

(9) During 2025, the Company recognized pre-tax non-cash recoverability charges of $315 million ($308 million after-tax) (2024 – $62 million ($47 million after-tax)) in depletion, depreciation and amortization expense relating to Offshore Africa. Recoverability charges are discussed in the 'Adjusted Depletion, Depreciation and Amortization – Exploration and Production' section of this MD&A.

ADJUSTED FUNDS FLOW

Adjusted funds flow is a non-GAAP financial measure that represents cash flows from operating activities as presented in the Company's consolidated statements of cash flows adjusted for the net change in non-cash working capital, abandonment expenditures, and movements in other long-term assets. The Company considers adjusted funds flow a key measure in evaluating its performance, as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment, repay debt, and provide returns to shareholders through dividends and share buybacks. A reconciliation for adjusted funds flow from cash flows from operating activities is presented below.

($ millions)		**2025**		2024		2023
Cash flows from operating activities	**$**	**15,106**	$	13,386	$	12,353
Net change in non-cash working capital		**(672)**		743		2,417
Abandonment expenditures		**771**		646		509
Movements in other long-term assets [(1)]		**255**		84		(5)
Adjusted funds flow	**$**	**15,460**	$	14,859	$	15,274

(1) Includes the unamortized cost of contributions to the Company's employee bonus program, interest on PRT and corporate tax recoveries in the North Sea, and prepaid cost of service tolls.

ADJUSTED NET EARNINGS FROM OPERATIONS AND ADJUSTED FUNDS FLOW, PER COMMON SHARE (BASIC AND DILUTED)

Adjusted net earnings from operations and adjusted funds flow, per common share (basic and diluted) are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 16 to the Company's audited consolidated financial statements. These non-GAAP measures, disclosed on a per share basis, enable a comparison to the per share amounts disclosed in the Company's financial statements prepared in accordance with IFRS Accounting Standards.

ABANDONMENT EXPENDITURES, NET

Abandonment expenditures, net, is a non-GAAP financial measure that represents the abandonment expenditures to settle asset retirement obligations as reflected in the Company's historical annual capital budgets. Abandonment expenditures, net is calculated as abandonment expenditures, as presented in the Company's audited consolidated statements of cash flows, adjusted for the impact of government grant income under the provincial well-site rehabilitation programs. Beginning in 2023, the Company no longer receives government grant income under these programs and as a result, the measure no longer differs from the most directly comparable GAAP measure and is not reported in this MD&A.

NETBACK

Netback is a non-GAAP ratio that represents net cash flows provided from core activities after the impact of all costs associated with bringing a product to market, on a per unit basis. The Company considers netback a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. Refer to the 'Operating Highlights – Exploration and Production', 'Per Unit Results – Exploration and Production', and 'Per Unit Results – Oil Sands Mining and Upgrading' sections of this MD&A for the netback calculations on a per unit basis for crude oil and NGLs and on a total barrels of oil equivalent basis.

The netback calculations include the realized price non-GAAP financial measure which is reconciled below to its respective line item in note 21 to the Company's audited consolidated financial statements.

During 2025, the Company revised its presentation of transportation expense and blending and feedstock costs, showing the expenses on a disaggregated basis in the consolidated statements of earnings. Previously, the Company aggregated transportation, blending and feedstock costs. The revision provides users with more information to evaluate the Company's performance. The audited consolidated financial statements and this MD&A have been updated for all periods presented. As a result, Transportation ($/BOE, $/bbl and $/Mcf) is no longer considered a non-GAAP ratio.

REALIZED PRICE ($/BBL AND $/BOE) – EXPLORATION AND PRODUCTION

Realized price ($/bbl and $/BOE) is a non-GAAP ratio calculated as realized crude oil and NGLs sales and total realized BOE sales (non-GAAP financial measures) divided by respective sales volumes. Realized crude oil and NGLs sales and total realized BOE sales is comprised of crude oil and NGLs sales and natural gas sales less blending and feedstock costs and other by-product sales, as disclosed in note 21 to the Company's audited consolidated financial statements. The Company considers realized price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit the Company obtained on the market for its crude oil and NGLs sales volumes and BOE sales volumes.

Reconciliations for Exploration and Production realized crude oil and NGLs sales and BOE sales and the calculations for realized price are presented below.

($ millions, except bbl/d and $/bbl)		2025		2024		2023
Crude oil and NGLs (bbl/d)						
North America		**570,262**		504,339		497,604
International						
North Sea		**9,146**		11,455		10,749
Offshore Africa		**4,520**		11,198		14,882
Total International		**13,666**		22,653		25,631
Total sales volumes		**583,928**		526,992		523,235
Crude oil and NGLs sales [1]	**$**	**19,591**	$	19,641	$	18,387
Less: Blending and feedstock costs [2]		**4,344**		4,643		4,568
Realized crude oil and NGLs sales	**$**	**15,247**	$	14,998	$	13,819
Realized price ($/bbl)	**$**	**71.54**	$	77.76	$	72.36

(1) Crude oil and NGLs sales in note 21 to the Company's audited consolidated financial statements.

(2) Blending and feedstock costs in note 21 to the Company's audited consolidated financial statements.

($ millions, except BOE/d and $/BOE)		2025		2024		2023
Barrels of oil equivalent (BOE/d)						
North America		**993,279**		860,367		854,138
International						
North Sea		**9,656**		11,791		11,034
Offshore Africa		**5,575**		12,728		16,638
Total International		**15,231**		24,519		27,672
Total sales volumes		**1,008,510**		884,886		881,810
Barrels of oil equivalent sales [1]	**$**	**21,921**	$	21,105	$	20,820
Less: Blending and feedstock costs [2]		**4,344**		4,643		4,568
Less: Sulphur (income) expense		**(85)**		3		(14)
Realized barrels of oil equivalent sales	**$**	**17,662**	$	16,459	$	16,266
Realized price ($/BOE)	**$**	**47.98**	$	50.82	$	50.54

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 21 to the Company's audited consolidated financial statements.

(2) Blending and feedstock costs in note 21 to the Company's audited consolidated financial statements.

NORTH AMERICA – REALIZED PRODUCT PRICES AND ROYALTIES

Realized crude oil and NGLs price ($/bbl) is a non-GAAP ratio calculated as realized crude oil and NGLs sales (non-GAAP financial measure) divided by sales volumes. Realized crude oil and NGLs sales is comprised of crude oil and NGLs sales less blending and feedstock costs, as disclosed in note 21 to the Company's audited consolidated financial statements. The Company considers the realized crude oil and NGLs price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its crude oil and NGLs sales volumes.

Crude oil and NGLs royalty rate is a non-GAAP ratio that is calculated as crude oil and NGLs royalties divided by realized crude oil and NGLs sales. The Company considers crude oil and NGLs royalty rate a key measure in evaluating its performance, as it describes the Company's royalties for crude oil and NGLs sales volumes on a per unit basis.

A reconciliation for North America realized crude oil and NGLs sales and the calculations for realized crude oil and NGLs prices and the royalty rates are presented below.

($ millions, except $/bbl and royalty rates)		**2025**		2024		2023
Crude oil and NGLs sales [1]	**$**	**19,102**	$	18,740	$	17,375
Less: Blending and feedstock costs [2]		**4,344**		4,643		4,568
Realized crude oil and NGLs sales	**$**	**14,758**	$	14,097	$	12,807
Realized crude oil and NGLs prices ($/bbl)	**$**	**70.90**	$	76.37	$	70.51
Crude oil and NGLs royalties [3]	**$**	**2,450**	$	2,842	$	2,340
Crude oil and NGLs royalty rates		**17%**		20%		18%

(1) Crude oil and NGLs sales in note 21 to the Company's audited consolidated financial statements.

(2) Blending and feedstock costs in note 21 to the Company's audited consolidated financial statements.

(3) Item is a component of royalties in note 21 to the Company's audited consolidated financial statements.

REALIZED PRODUCT PRICES – OIL SANDS MINING AND UPGRADING

Realized SCO sales price ($/bbl) is a non-GAAP ratio calculated as realized SCO sales (non-GAAP financial measure) divided by SCO sales volumes. Realized SCO sales is comprised of crude oil and NGLs sales less blending and feedstock costs, as disclosed in note 21 to the Company's audited consolidated financial statements. The Company considers realized SCO sales price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its SCO sales volumes.

Reconciliations for Oil Sands Mining and Upgrading realized SCO sales and the calculation for realized SCO sales price on a per unit basis are presented below.

($ millions, except for bbl/d and $/bbl)		**2025**		2024		2023
SCO sales volumes (bbl/d)		**567,335**		468,280		449,282
Crude oil and NGLs sales [1]	**$**	**20,112**	$	19,263	$	18,661
Less: Blending and feedstock costs [2]		**2,218**		2,462		2,253
Realized SCO sales	**$**	**17,894**	$	16,801	$	16,408
Realized SCO sales price ($/bbl)	**$**	**86.41**	$	98.03	$	100.06

(1) Crude oil and NGLs sales in note 21 to the Company's audited consolidated financial statements.

(2) Blending and feedstock costs in note 21 to the Company's audited consolidated financial statements.

NET CAPITAL EXPENDITURES

Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's consolidated statements of cash flows, adjusted for the net change in non-cash working capital, net proceeds from investments, and cash flows from investing activities not included in the Company's capital budget. The Company includes acquisition and disposition capital for property, plant and equipment and exploration and evaluation assets in net capital expenditures at close of the transactions. The Company considers net capital expenditures a key measure in evaluating its performance, as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. A reconciliation of net capital expenditures is presented below.

($ millions)		**2025**		2024		2023
Cash flows used in investing activities	**$**	**6,687**	$	14,095	$	4,858
Working capital acquired from Chevron		**—**		(115)		—
Net proceeds from investment		**—**		575		—
Net change in non-cash working capital		**(108)**		(124)		51
Net capital expenditures		**6,579**		14,431		4,909
Abandonment expenditures		**771**		646		509
Capital and abandonment expenditures	**$**	**7,350**	$	15,077	$	5,418

LIQUIDITY

Liquidity is a non-GAAP financial measure that represents the availability of readily available undrawn bank credit facilities, cash and cash equivalents, and other highly liquid assets to meet short-term funding requirements and to assist in assessing the Company's financial position. The Company's calculation of liquidity is presented below.

($ millions)		**2025**		2024		2023
Undrawn bank credit facilities	**$**	**5,668**	$	4,562	$	5,450
Cash and cash equivalents		**673**		131		877
Investments [(1)]		**—**		—		525
Liquidity	**$**	**6,341**	$	4,693	$	6,852

(1) During 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. for $25.65 per common share with net proceeds at close, after fees and expenses, of $575 million.

LONG-TERM DEBT, NET

Long-term debt, net, is a capital management measure that represents long-term debt, including the current portion of long-term debt, less cash and cash equivalents, as disclosed in note 15 to the Company's audited consolidated financial statements. A reconciliation of the Company's long-term debt, net is presented below.

($ millions)		**2025**		2024		2023
Long-term debt	**$**	**16,617**	$	18,819	$	10,799
Less: Cash and cash equivalents		**673**		131		877
Long-term debt, net	**$**	**15,944**	$	18,688	$	9,922

DEBT TO BOOK CAPITALIZATION

Debt to book capitalization is a capital management measure intended to enable financial statement users to evaluate the Company's capital structure, as disclosed in note 15 to the Company's audited consolidated financial statements.

AFTER-TAX RETURN ON AVERAGE CAPITAL EMPLOYED

After-tax return on average capital employed as defined by the Company is a non-GAAP ratio. The ratio is calculated as net earnings plus after-tax interest and other financing expense for the twelve month trailing period as a percentage of average capital employed (defined as current and long-term debt plus shareholders' equity) for the twelve month trailing period. The Company considers this ratio a key measure in evaluating the Company's ability to generate profit and the efficiency with which it employs capital. A reconciliation of the Company's after-tax return on average capital employed is presented below.

($ millions, except ratios)		**2025**		2024		2023
Interest adjusted after-tax return:						
Net earnings, 12 months trailing [1]	**$**	**10,820**	$	6,106	$	8,233
Interest and other financing expense, net of tax, 12 months trailing [2]		**640**		454		490
Interest adjusted after-tax return	**$**	**11,460**	$	6,560	$	8,723
12 months average current portion long-term debt [3]	**$**	**1,293**	$	1,525	$	1,259
12 months average long-term debt [3]		**16,149**		10,642		10,354
12 months average common shareholders' equity [3]		**41,208**		39,635		38,974
12 months average capital employed	**$**	**58,650**	$	51,802	$	50,587
After-tax return on average capital employed		**20%**		13%		17%

(1) Net earnings, 12 months trailing for 2025 includes a gain on acquisition, disposition, and remeasurement of $4,989 million associated with the AOSP asset swap. Further details are disclosed in note 6 to the Company's audited consolidated financial statements.

(2) The blended tax rate on interest was approximately 23% for each of the periods presented.

(3) For the purpose of this non-GAAP ratio, the measurement of average current and long-term debt and common shareholders' equity are determined on a consistent basis, as an average of the opening and quarterly period end values for the 12 month trailing period for each of the periods presented.

Other

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flows from operating activities and net earnings due to changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2025, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flows from Operating Activities ($ millions)		**Cash flows from Operating Activities** (per common share, basic)		**Net earnings** ($ millions)		**Net earnings** (per common share, basic)
Price changes							
Crude oil – WTI US$1.00/bbl	$	409	$	0.20	$	409	$ 0.20
Natural gas – AECO C$0.10/Mcf [1]							
Excluding financial derivatives	$	52	$	0.02	$	52	$ 0.02
Including financial derivatives	$	51	$	0.02	$	51	$ 0.02
Volume changes							
Crude oil – 10,000 bbl/d	$	136	$	0.07	$	114	$ 0.05
Natural gas – 10 MMcf/d	$	3	$	—	$	(3)	$ —
Foreign currency rate change							
$0.01 change in US$ [1]							
Including financial derivatives	$	267	$	0.13	$	78	$ 0.04
Interest rate change – 1%	$	33	$	0.02	$	33	$ 0.02

(1) For details of financial instruments in place, refer to note 18 to the Company's audited consolidated financial statements.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2025	2024	2023
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**561,238**	**545,811**	**584,625**	**585,497**	**569,401**	509,288	496,100
North America – Oil Sands Mining and Upgrading [1]	**595,116**	**463,808**	**581,136**	**619,901**	**565,102**	472,245	451,339
International							
North Sea	**11,507**	**7,761**	**7,045**	**7,618**	**8,468**	11,536	12,639
Offshore Africa	**5,943**	**1,769**	**2,798**	**2,348**	**3,204**	12,534	13,452
Total International	**17,450**	**9,530**	**9,843**	**9,966**	**11,672**	24,070	26,091
Total Crude oil and NGLs	**1,173,804**	**1,019,149**	**1,175,604**	**1,215,364**	**1,146,175**	1,005,603	973,530
Natural gas (MMcf/d) [2]							
North America	**2,436**	**2,398**	**2,658**	**2,657**	**2,538**	2,136	2,139
International							
North Sea	**4**	**3**	**2**	**3**	**3**	2	2
Offshore Africa	**11**	**6**	**8**	**—**	**6**	9	10
Total International	**15**	**9**	**10**	**3**	**9**	11	12
Total Natural gas	**2,451**	**2,407**	**2,668**	**2,660**	**2,547**	2,147	2,151
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**967,245**	**945,451**	**1,027,598**	**1,028,326**	**992,419**	865,314	852,633
North America – Oil Sands Mining and Upgrading [1]	**595,116**	**463,808**	**581,136**	**619,901**	**565,102**	472,245	451,339
International							
North Sea	**12,241**	**8,245**	**7,381**	**8,106**	**8,978**	11,873	12,925
Offshore Africa	**7,746**	**2,854**	**4,146**	**2,348**	**4,258**	14,064	15,208
Total International	**19,987**	**11,099**	**11,527**	**10,454**	**13,236**	25,937	28,133
Total Barrels of oil equivalent	**1,582,348**	**1,420,358**	**1,620,261**	**1,658,681**	**1,570,757**	1,363,496	1,332,105

(1) SCO production before royalties excludes SCO consumed internally as diesel.

(2) Natural gas production volumes approximate sales volumes.

PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2025	2024	2023
Crude oil and NGLs ($/bbl) [1]							
Realized price [2]	$ 79.85	$ 69.58	$ 72.57	$ 64.42	$ 71.54	$ 77.76	$ 72.36
Transportation [3]	6.40	7.65	6.93	7.14	7.02	5.50	4.23
Realized price, net of transportation [2]	73.45	61.93	65.64	57.28	64.52	72.26	68.13
Royalties [4]	14.36	9.20	13.10	9.46	11.53	14.85	12.55
Production expense [5]	15.74	14.03	13.18	14.35	14.33	14.72	16.12
Netback [2]	$ 43.35	$ 38.70	$ 39.36	$ 33.47	$ 38.66	$ 42.69	$ 39.46
Natural gas ($/Mcf) [1]							
Realized price [6]	$ 3.13	$ 2.58	$ 1.49	$ 2.89	$ 2.51	$ 1.86	$ 3.10
Transportation [3]	0.63	0.59	0.57	0.56	0.59	0.62	0.56
Realized price, net of transportation	2.50	1.99	0.92	2.33	1.92	1.24	2.54
Royalties [4]	0.11	0.08	0.02	0.09	0.08	0.05	0.13
Production expense [5]	1.20	1.11	1.16	1.10	1.14	1.22	1.30
Netback [7]	$ 1.19	$ 0.80	$ (0.26)	$ 1.14	$ 0.70	$ (0.03)	$ 1.11
Barrels of oil equivalent ($/BOE) [1]							
Realized price [2]	$ 54.95	$ 47.17	$ 45.31	$ 44.85	$ 47.98	$ 50.82	$ 50.54
Transportation [3]	5.34	5.94	5.38	5.56	5.54	4.78	3.88
Realized price, net of transportation [2]	49.61	41.23	39.93	39.29	42.44	46.04	46.66
Royalties [4]	8.76	5.58	7.53	5.73	6.90	8.96	7.77
Production expense [5]	12.23	10.95	10.50	11.08	11.18	11.73	12.74
Netback [2]	$ 28.62	$ 24.70	$ 21.90	$ 22.48	$ 24.36	$ 25.35	$ 26.15

(1) For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

(2) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(3) Calculated as transportation expense divided by respective sales volumes.

(4) Calculated as royalties divided by respective sales volumes.

(5) Calculated as production expense divided by respective sales volumes.

(6) Calculated as natural gas sales divided by natural gas sales volumes.

(7) Natural gas netbacks exclude NGLs netbacks derived from the Company's liquids-rich natural gas plays.

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING

	Q1	Q2	Q3	Q4	2025	2024	2023
Crude oil and NGLs ($/bbl) [1]							
Realized SCO sales price [2]	$ 95.52	$ 87.22	$ 87.85	$ 75.90	$ 86.41	$ 98.03	$ 100.06
Bitumen royalties [3]	18.22	11.59	15.80	9.54	13.84	17.23	14.43
Transportation [4]	3.21	3.73	3.86	2.56	3.31	2.91	1.89
Production expense [5]	21.88	26.53	21.29	21.84	22.66	22.88	24.32
Netback [2]	$ 52.21	$ 45.37	$ 46.90	$ 41.96	$ 46.60	$ 55.01	$ 59.42

(1) For SCO sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(2) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(3) Calculated as royalties divided by sales volumes.

(4) Calculated as transportation expense divided by sales volumes.

(5) Calculated as production expense divided by sales volumes.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2025	2024
TSX – C$						
Trading volume (thousands)	**809,387**	**1,007,979**	**998,028**	**1,030,966**	**3,846,360**	3,025,819
Share Price ($/share)						
High	**$ 48.26**	**$ 46.92**	**$ 46.12**	**$ 49.20**	**$ 49.20**	$ 56.50
Low	**$ 37.11**	**$ 34.92**	**$ 40.62**	**$ 41.67**	**$ 34.92**	$ 40.02
Close	**$ 44.28**	**$ 42.80**	**$ 44.50**	**$ 46.49**	**$ 46.49**	$ 44.38
Market capitalization as at December 31, ($ millions)					**$ 96,773**	$ 93,331
Shares outstanding (thousands)					**2,081,578**	2,102,996
NYSE – US$						
Trading volume (thousands)	**438,860**	**412,850**	**381,546**	**435,083**	**1,668,339**	1,310,294
Share Price ($/share)						
High	**$ 33.51**	**$ 34.33**	**$ 33.24**	**$ 35.12**	**$ 35.12**	$ 41.29
Low	**$ 25.62**	**$ 24.65**	**$ 29.30**	**$ 29.69**	**$ 24.65**	$ 29.23
Close	**$ 30.80**	**$ 31.40**	**$ 31.96**	**$ 33.85**	**$ 33.85**	$ 30.87
Market capitalization as at December 31, ($ millions)					**$ 70,461**	$ 64,919
Shares outstanding (thousands)					**2,081,578**	2,102,996

Additional Disclosure

CERTIFICATIONS

The required disclosure is included in Exhibits 31.1, 31.2, 32.1, 32.2 and 97.1 to this Annual Report on Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

As of the end of the registrant's fiscal year ended December 31, 2025, an evaluation of the effectiveness of Canadian Natural's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")), was carried out by Canadian Natural's management with the participation of Canadian Natural's principal executive officer and principal financial officer. Based upon the evaluation, Canadian Natural's principal executive officer and principal financial officer have concluded that as of the end of the fiscal year, Canadian Natural's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (ii) accumulated and communicated to Canadian Natural's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

It should be noted that while Canadian Natural's principal executive officer and principal financial officer believe that Canadian Natural's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect Canadian Natural's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The required disclosure is included in the "Management's Assessment of Internal Control Over Financial Reporting" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2025, filed as part of this Annual Report on Form 40-F.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

The required disclosure is included in the "Report of Independent Registered Public Accounting Firm" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2025, filed as part of this Annual Report on Form 40-F.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

During the fiscal year ended December 31, 2025, there were no changes in Canadian Natural's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, Canadian Natural's internal control over financial reporting.

NOTICES PURSUANT TO REGULATION BTR

None.

AUDIT COMMITTEE FINANCIAL EXPERT

The Board of Directors of Canadian Natural has determined that Ms. C.M. Best, Ms. S.A.M. Brown and Mr. W.A. Gobert, each qualify as an "audit committee financial expert" (as defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its Audit Committee. Ms. C.M. Best, Ms. S.A.M. Brown and Mr. W.A. Gobert are, as are all members of the Audit Committee of the Board of Directors of Canadian Natural, "independent" as such term is defined in the rules of the New York Stock Exchange.

CODE OF ETHICS

Canadian Natural has a long-standing Code of Integrity, Business Ethics and Conduct (the "Code of Ethics"), which covers such topics as employment standards, conflict of interest, the treatment of confidential information and trading in Canadian Natural's shares and is designed to ensure that Canadian Natural's business is consistently conducted in a legal and ethical manner. Each director and all employees, including each member of senior management and more specifically the principal executive officer, principal financial officer, principal accounting officer or controller and persons performing similar functions, are required to abide by the Code of Ethics. The Nominating, Governance and Risk Committee of the Board of Directors reviews the Code of Ethics annually to ensure it addresses appropriate topics and complies with regulatory requirements and recommends any appropriate changes to the Board for approval.

Any waivers of or amendments to the Code of Ethics must be approved by the Board of Directors and will be appropriately disclosed. In the past fiscal year, there have not been any waivers, including implicit waivers, from any provisions of the Code of Ethics.

The Code of Ethics is available through the System for Electronic Document and Analysis and Retrieval (now referred to as SEDAR+) at www.sedarplus.ca.

Canadian Natural hereby undertakes to provide to any person, without charge and upon request, a copy of its Code of Ethics. Requests for copies can also be made by contacting: Stephanie A. Graham, Corporate Secretary and Associate General Counsel, Canada, Canadian Natural Resources Limited, 2100-855 2nd Street, S.W., Calgary, Alberta, Canada T2P 4J8.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

PricewaterhouseCoopers LLP ("PwC"), Calgary, Alberta, Canada (PCAOB ID 271), has been the auditor of Canadian Natural since 1973. The aggregate amounts billed by PwC for each of the last two fiscal years for audit fees, audit-related fees, tax fees and all other fees, excluding expenses, are set forth below.

Audit Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural ended December 31, 2025 and December 31, 2024, for professional services rendered by PwC for the audit of its internal controls and annual consolidated financial statements in connection with statutory and regulatory filings or engagements for those fiscal years, unaudited reviews of the first, second and third quarters of its interim consolidated financial statements and audits of certain of Canadian Natural's subsidiary companies' annual financial statements were $2,702,000 for 2025 and were $2,557,000 for 2024.

Audit-Related Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2025 and December 31, 2024, for audit-related services by PwC including Crown Royalty Statements, GHG verification and emissions (2024 only), and pension reporting were $490,000 for 2025 and were $1,284,000 for 2024. Canadian Natural's Audit Committee approved all of these audit-related services.

Tax Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2025 and December 31, 2024, for professional services rendered by PwC for tax services related to corporate tax return matters were $421,000 for 2025 and were $413,000 for 2024. Canadian Natural's Audit Committee approved all of these tax-related services.

All Other Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2025 and December 31, 2024 for other services were $107,000 for 2025 and were $63,000 for 2024, related to French translation services and accessing resource materials through PwC's accounting literature library. Canadian Natural's Audit Committee approved all of the noted services.

Audit Committee Pre-Approval Policies and Procedures

The Audit Committee's duties and responsibilities include the review and approval of fees to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors. The Audit Committee also reviews and approves the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department prior to the commencement of the audit and reviews and approves proposed non-audit services to be provided by the independent auditors, except those non-audit services prohibited by legislation. Canadian Natural did not rely on the de minimis exemption provided by paragraph (c)(7)(i)(c) of Rule 2.01 of Regulation S-X in 2025.

OFF BALANCE SHEET ARRANGEMENTS

The Company does not have any off-balance sheet arrangements (which are not otherwise disclosed in the Company's Management's Discussion and Analysis for the year ended December 31, 2025, or audited consolidated financial statements for the years ended December 31, 2025 and 2024) that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

IDENTIFICATION OF THE AUDIT COMMITTEE

Canadian Natural has a separately designated standing audit committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The current members of the Audit Committee are Ms. C.M. Best, who chairs the Audit Committee, Messrs. W.A. Gobert, G. D. Giffin, D. A. Tuer, Ms. S.A.M. Brown and Ms. C.M. Healy.

MINE SAFETY DISCLOSURE

Not Applicable.

CORPORATE GOVERNANCE

Canadian Natural's corporate governance practices and disclosure of those practices are in compliance with National Policy 58-201 Corporate Governance Guidelines and National Instrument 58-101 Disclosure of Corporate Governance Practices. Canadian Natural, as a foreign private issuer in the United States, may rely on home jurisdiction listing standards for compliance with most of the New York Stock Exchange (NYSE) Corporate Governance Listing Standards but must disclose any significant differences between its corporate governance practices and those required for U.S. companies listed on the NYSE.

Canadian Natural follows Toronto Stock Exchange (TSX) rules with respect to shareholder approval of equity compensation plans and material revisions to such plans. TSX rules provide that only the creation of or material amendments to equity compensation plans which provide for new issuance of securities are subject to shareholder approval. However, the NYSE requires shareholder approval of all equity compensation plans whether they provide for the delivery of newly issued securities, or rely on securities acquired in the open market by the issuing company for the purposes of redistribution to plan beneficiaries, and material revisions to such plans. Canadian Natural has a performance share unit plan pursuant to which common shares are purchased through the TSX. This is not a new issue of securities under the performance share unit plan and under TSX rules the plan is not subject to shareholder approval.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

Undertaking

Canadian Natural undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

Consent to Service of Process

Canadian Natural has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the agent for service of process of Canadian Natural shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the registrant.

SIGNATURES

Pursuant to the requirements of the Exchange Act, Canadian Natural 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.

Dated this 25th day of March, 2026.

CANADIAN NATURAL RESOURCES LIMITED

By: SIGNED "SCOTT G. STAUTH"
Name: Scott G. Stauth
Title: President

Documents filed as part of this report:

EXHIBIT INDEX

Exhibit No.	Description
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Sproule International Limited, Independent Petroleum Engineering Consultants.
23.3	Consent of GLJ Ltd., Independent Petroleum Engineering Consultants.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 .
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
32.1	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
32.2	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
97.1	Executive Compensation Recovery Policy
99.1	Supplementary Oil & Gas Information (Unaudited) for the fiscal year ended December 31, 202 5
101	Interactive data files with respect to the consolidated financial statements for the fiscal year ended December 31, 2025.

EXHIBIT 23.1



Consent of Independent Registered Public Accounting Firm

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2025 of Canadian Natural Resources Limited of our report dated March 4, 2026, relating to the consolidated financial statements, and the effectiveness of internal control over financial reporting, which appears in this Annual Report on Form 40-F.

We also consent to the incorporation by reference in the Registration Statement on Form F-10 (No. 333-289937) of Canadian Natural Resources Limited of our report dated March 4, 2026 referred to above. We also consent to reference to us under the heading "Interests of Experts" in the Annual Information Form, included in this Annual Report on Form 40-F, which is incorporated by reference in such Registration Statements.

/s/ PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta, Canada
March 25, 2026

PricewaterhouseCoopers LLP
111 5th Avenue South West, Suite 2900
Calgary, Alberta, Canada T2P 5L3
T.: +1 403 509 7500, F.: +1 403 781 1825
Fax to mail: ca_calgary_main_fax@pwc.com

"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

EXHIBIT 23.2

Sproule ERCE

LETTER OF CONSENT

Canadian Natural Resources Limited
2100, 855 - 2nd Street SW
CALGARY AB T2P 4J8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

We consent to the use of our name and our reports with respect to the reserves data of Canadian Natural Resources Limited (the "Company"), and the information derived from our reports, included and incorporated by reference in the Company's

(i) Annual Report on Form 40-F for the year ended December 31, 2025, including the Annual Information Form included therein; and

(ii) Registration Statement on Form F-10 (File No. 333-289937) filed with the Securities and Exchange Commission.

Sincerely,
SPROULE INTERNATIONAL LIMITED

SIGNED “STEVEN J. GOLKO”

Steven J. Golko, P.Eng.
Senior Vice President,
Reserves & Resources
Calgary, Alberta, Canada

March 25, 2026

EXHIBIT 23.3

LETTER OF CONSENT

Canadian Natural Resources Limited
2100, 855 - 2nd Street SW
CALGARY AB T2P 4J8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

We consent to the use of our name and our report with respect to the reserves data of Canadian Natural Resources Limited (the "Company"), and the information derived from our report, included and incorporated by reference in the Company's

(i) Annual Report on Form 40-F for the year ended December 31, 2025, including the Annual Information Form included therein; and

(ii) Registration Statement on Form F-10 (File No. 333-289937) filed with the Securities and Exchange Commission.

Yours truly,

GLJ LTD.

SIGNED "TRACY BELLINGHAM"

Tracy Bellingham, P.Eng.
Executive Vice President & COO

Calgary, Alberta, Canada
March 25, 2026

EXHIBIT 31.1

Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a)
of the Securities Exchange Act of 1934

CERTIFICATION

I, Scott G. Stauth, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;
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(s) 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(s) 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.

Dated this 25th day of March, 2026.

SIGNED "SCOTT G. STAUTH"
Scott G. Stauth
President (Principal Executive Officer),
Canadian Natural Resources Limited

EXHIBIT 31.2

Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a)
of the Securities Exchange Act of 1934

CERTIFICATION

I, Victor C. Darel, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;
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(s) 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(s) 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.

Dated this 25th day of March, 2026.

SIGNED "VICTOR C. DAREL"
Victor C. Darel
Chief Financial Officer (Principal Financial Officer),
Canadian Natural Resources Limited

EXHIBIT 32.1

Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350)

In connection with the Annual Report of Canadian Natural Resources Limited (the "Company") on Form 40-F for the fiscal year ending December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Scott G.Stauth, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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.

DATED this 25th day of March, 2026.

SIGNED "SCOTT G. STAUTH"
Scott G. Stauth
President (Principal Executive Officer),
Canadian Natural Resources Limited

EXHIBIT 32.2

Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350)

In connection with the Annual Report of Canadian Natural Resources Limited (the "Company") on Form 40-F for the fiscal year ending December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Victor C. Darel, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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.

DATED this 25th day of March, 2026.

SIGNED "VICTOR C. DAREL"
Victor C. Darel
Chief Financial Officer (Principal Financial Officer),
Canadian Natural Resources Limited

EXHIBIT 97.1

Canadian Natural Resources Limited

EXECUTIVE COMPENSATION RECOVERY POLICY

The Board of Directors ("**Board**") of Canadian Natural Resources Limited (the "Company") has adopted this Policy in accordance with applicable laws and stock exchange rules.

Application of Policy

This Policy applies in the event of:

(i) any accounting restatement ("**Restatement**") of the Company's financial results due to a material non-compliance with the financial reporting requirements under applicable securities laws; and

(ii) any circumstance where the Board of Directors, in its discretion, has determined that an Executive Officer (defined below) of the Company has engaged in wrongdoing or material misconduct that harms or otherwise prejudices the Company, including its reputation ("Executive Misconduct"), in addition to any other disciplinary measures that may be levied.

Executive Officers Subject to the Policy

All executive officers of the Company are subject to this Policy, being the Executive Chairman, President, Chief Financial Officer, Principal Accounting Officer, Chief Operating Officers, Senior Vice-Presidents, any Vice-President of the Company in charge of a principal business unit, division or function, and any other person who performs a significant policy-making function for the Company (the "Executive Officers"). In relation to a Restatement, this Policy shall apply even if an Executive Officer had no responsibility for the financial statement errors which resulted in the Restatement. This Policy also applies to any former Executive Officer who, within the preceding fiscal three years, ceased to be an Executive Officer after this Policy came into place.

Part I - Recovery Arising from Restatement

Part I (A)-(D) shall apply to compensation recovery in the event of a Restatement.

A. Compensation Subject to the Policy; Recovery Period

This Policy shall apply to incentive-based compensation received on or after November 1, 2023 (the " **Effective Date**"). For purposes of this Policy, "incentive-based compensation" means compensation (including any cash or equity compensation) that is granted, earned, vested or received by an Executive Officer based wholly or in part upon the attainment of any "financial reporting measure" during the period (the "**Recovery Period**") being any of the three most recently completed fiscal years immediately preceding:

(i) the date that the Company's Board (or Audit Committee) concludes, or reasonably should have concluded, that the Company is required to prepare a Restatement, or

(ii) the date that a court, regulator, or other legally authorized body directs the Company to prepare a Restatement.

"Financial reporting measures" are those that are determined and presented in accordance with the accounting principles used in preparing the Company's financial statements and any measures derived wholly or in part from such financial information (including non-GAAP measures, stock price and total shareholder return). Incentive-based compensation is deemed "received" in the fiscal period during which the applicable financial reporting measure (as specified in the terms of the award) is attained, even if the payment or grant occurs after the end of that fiscal period. For the avoidance of doubt, the Recovery Period with respect to an Executive Officer applies to incentive-based compensation received by the Executive Officer (a) after beginning services as an Executive Officer (including compensation derived from an award authorized before the individual is newly hired as an Executive Officer, e.g. inducement grants) and (b) if that person served as an Executive Officer at any time during the fiscal period described above for such incentive-based compensation.

B. Amount Required to be Repaid Pursuant to this Policy

Except as otherwise set forth below, the amount of incentive-based compensation that must be repaid by an Executive Officer shall be determined in accordance with applicable laws and stock exchanges rules and if no such rules apply shall be the amount of incentive-based compensation received by the Executive Officer that exceeds the amount of incentive-based compensation that otherwise would have been received had it been determined based on the Restatement (the "**Recoverable Amount**") as determined by the Company, acting reasonably. After a Restatement, the Company will determine whether, based on that financial reporting measure as calculated relying on the original financial statements, an Executive Officer received a greater amount of incentive-based compensation than would have been received applying the recalculated financial measure. Where

incentive-based compensation is based only in part on the achievement of a financial reporting measure performance goal, the Company will, acting reasonably, determine the portion of the original incentive-based compensation derived from the financial reporting measure which was restated and will recalculate the affected portion based on the financial reporting measure as restated to determine the difference between the greater amount based on the original financial statements and the lesser amount that would have been received based on the Restatement. The Recoverable Amounts will be calculated on a pre-tax basis to ensure that the Company recovers the full amount of incentive-based compensation that was erroneously awarded. Documentation of the Company's calculation of the Recoverable Amount shall be maintained and shall be provided to the applicable stock exchange as required by applicable stock exchange rules.

In no event shall the Company be required to award Executive Officers an additional payment if the restated or accurate financial results would have resulted in a higher incentive compensation payment. If, due to a Restatement, equity compensation is recoverable from an Executive Officer, the Company will recover the excess portion of the equity award that would not have been granted or vested based on the Restatement, as follows:

(i) if the equity award is still outstanding, the Executive Officer will forfeit the excess portion of the award;

(ii) if the equity award has been exercised or settled into shares (the "Underlying Shares"), and the Executive Officer still holds the Underlying Shares, the Company will recover the number of Underlying Shares relating to the excess portion of the award (less any exercise price paid for the Underlying Shares); and

(iii) if the Underlying Shares have been sold by the Executive Officer, the Company will recover the proceeds received by the Executive Officer from the sale of the Underlying Shares relating to the excess portion of the award (less any exercise price paid for the Underlying Shares).

The Compensation Committee of the Board will take such reasonably prompt action as it deems appropriate, in its sole and absolute discretion, to recover the Recoverable Amount, unless it is determined that it would be impracticable to recover the such amount because (1) the Company has made a reasonable and documented attempt to recover the Recoverable Amount, has provided such documentation to the applicable stock exchange and has determined that the direct costs of enforcing recovery would exceed the Recoverable Amount, (2) recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company, to fail to meet the requirements of 26 U.S.C. Section 401(a)(13) or 26 U.S.C. Section 411(a) and regulations thereunder, or (3) if the recovery of the incentive-based compensation would, based on an opinion of counsel, be in violation of the laws of Canada or any applicable province thereof.

C. Additional Recovery Required by Section 304 of the Sarbanes-Oxley Act of 2002

In addition, if the Company is required to prepare an accounting restatement due to the material noncompliance of the Company, as a result of misconduct, with any financial reporting requirement under applicable securities laws, then, in accordance with Section 304 of the U.S. Sarbanes-Oxley Act of 2002, the Executive Chairman, President, Chief Financial Officer and any Chief Operating Officer (at the time the financial document embodying such financial reporting requirement was originally issued) shall reimburse the Company for:

(i) any bonus or other incentive-based or equity-based compensation received from the Company during the 12-month period following the first public issuance or filing with the Commission (whichever first occurs) of such financial document; and

(ii) any profits realized from the sale of securities of the Company during that 12-month period.

D. Crediting of Recovery Amounts

To the extent that subsections A, B, C and D of this Policy would provide for recovery of incentive-based compensation recoverable by the Company pursuant to Section 304 of the Sarbanes-Oxley Act, in accordance with subsection E of this Policy, and/or any other recovery obligations (including pursuant to employment agreements, or plan awards), the amount such Executive Officer has already reimbursed the Company shall be credited to the required recovery under this Policy. Recovery pursuant to the other provisions of this Policy does not preclude recovery under subsection E of this Policy, to the extent any applicable amounts have not already been reimbursed to the Company.

Part II – Recovery Arising from Executive Misconduct

In relation to an Executive Officer's Executive Misconduct, the Board may, in its discretion after reasonable inquiry, take either or both of the following actions in relation to such Executive Officer, in addition to any disciplinary action undertaken by management of the Corporation:

(i) reject or reduce any bonus recommendation presented to the Compensation Committee of the Board by the management of the Corporation; and

(ii) require the recovery (on a pre-tax basis) of all or a portion of cash incentive-based payments awarded or made to the Executive Officer in the year in which the Executive Misconduct occurs or is discovered to have occurred.

Part III - General Provisions

This Policy may be amended by the Board from time to time. Implementation of, and changes to, this Policy will be communicated to all persons to whom this Policy applies.

The Company will not indemnify or provide insurance to cover any repayment of incentive-based compensation in accordance with this Policy. The provisions of this Policy apply to the fullest extent of the law; provided however, to the extent that any provisions of this Policy are found to be unenforceable or invalid under any applicable law, such provision will be applied to the maximum extent permitted, and shall automatically be deemed amended in a manner consistent with its objectives to the extent necessary to conform to any limitations required under applicable law.

This Policy is in addition to (and not in lieu of) any right of repayment, forfeiture or right of offset against any Executive Officer that is required pursuant to any other statutory repayment requirement (regardless of whether implemented at any time prior to or following the adoption of this Policy). Nothing in this Policy in any way detracts from or limits any obligation that those subject to it have in law or pursuant to a management, employment, consulting or other agreement with the Company or any of its subsidiaries.

All determinations and decisions made by the Board (or any committee thereof, including the Compensation Committee) pursuant to the provisions of this Policy shall be final, conclusive and binding on the Company, its subsidiaries and the persons to whom this Policy applies. If you have questions about the interpretation of this Policy, please contact the Chief Financial Officer or the Vice President, Legal & General Counsel.

Supplementary Oil & Gas Information for the Fiscal Year Ended December 31, 2025 (Unaudited)

This supplementary crude oil and natural gas information is provided in accordance with the United States Financial Accounting Standards Board ("FASB") Topic 932 – "Extractive Activities – Oil and Gas" and where applicable, financial information is prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

For the years ended December 31, 2025, 2024, 2023, and 2022 the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

There are significant differences in the type of volumes disclosed and the basis from which the volumes are economically determined under the United States Securities and Exchange Commission ("SEC") requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using 12-month average prices and current costs; whereas NI 51-101 requires gross reserves, before royalties, using forecast pricing and costs. Therefore the difference between the reported numbers under the two disclosure standards can be material.

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2025, 2024, 2023, and 2022 the Company used the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The Company has used the following 12-month average benchmark prices to determine its 2025 and 2024 reserves for SEC requirements.

	Crude Oil and NGLs						Natural Gas		
	WTI	WCS	Canadian Light Sweet	Cromer LSB	Brent	Edmonton C5+	Henry Hub	AECO	BC Westcoast Station 2
	(US$/bbl)	(C$/bbl)	(C$/bbl)	(C$/bbl)	(US$/bbl)	(C$/bbl)	(US$/MMBtu)	(C$/MMBtu)	(C$/MMBtu)
2025	**65.68**	**76.91**	**87.03**	**85.79**	**68.59**	**90.25**	**3.70**	**1.75**	**1.10**
2024	74.88	80.78	96.35	93.44	78.81	98.90	2.37	1.28	0.91

A foreign exchange rate of US$0.7131/C$1.00 was used in the 2025 evaluation (2024 - US$0.7325/C$1.00), determined on the same basis as the 12-month average price.

Net Proved Crude Oil and Natural Gas Reserves

The Company retains Independent Qualified Reserves Evaluators to evaluate and review the Company's proved crude oil, bitumen, synthetic crude oil ("SCO"), natural gas, and natural gas liquids ("NGLs") reserves.

- For the years ended December 31, 2025, 2024, 2023, and 2022, the reports by GLJ Ltd. ("GLJ") covered 100% of the Company's Oil Sands Mining and Upgrading SCO reserves. As of December 31, 2025, GLJ also evaluated the Company's mining bitumen reserves. With the inclusion of non-traditional resources within the definition of "oil and gas producing activities" in the SEC's modernization of oil and gas reporting rules, effective January 1, 2010 these reserves volumes are included within the Company's crude oil and natural gas reserves totals.
- For the years ended December 31, 2025 and 2024, the reports by Sproule International Limited, and for the years ended December 31, 2023 and 2022, the reports by Sproule Associates Limited and Sproule International Limited, covered 100% of the Company's crude oil, thermal bitumen, natural gas and NGLs reserves.

Proved crude oil and natural gas reserves, as defined within the SEC's Regulation S-X, are the estimated quantities of oil and gas that by analysis of geoscience and engineering data demonstrate with reasonable certainty to be economically producible, from a given date forward, from known reservoirs under existing economic conditions, operating methods and government regulations. Developed crude oil and natural gas reserves are reserves of any category that can be expected to be recovered from 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 drilling a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Undeveloped crude oil and natural gas reserves are reserves of any category 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.

Estimates of crude oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following tables summarize the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2025, 2024, 2023 and 2022:

	North America							
Crude Oil and NGLs (MMbbl) [1]	**Synthetic Crude Oil**	**Bitumen** [2]	**Crude Oil**	**NGLs**	**North America Total**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves								
Reserves, December 31, 2022	5,390	2,546	321	375	8,632	11	57	8,700
Extensions and discoveries	162	67	14	37	280	—	—	280
Improved recovery	28	9	7	30	75	—	—	75
Purchases of reserves in place	—	—	—	—	—	—	—	—
Sales of reserves in place	—	—	—	(1)	(1)	—	—	(1)
Production	(141)	(102)	(27)	(20)	(289)	(5)	(4)	(298)
Economic revisions due to prices [3]	333	123	10	18	484	—	1	485
Revisions of prior estimates	68	26	(2)	3	94	3	1	98
Reserves, December 31, 2023	5,840	2,669	325	442	9,276	9	54	9,339
Extensions and discoveries	—	62	13	18	93	—	—	93
Improved recovery	1	7	2	10	21	—	—	21
Purchases of reserves in place	701	1	7	131	839	—	—	839
Sales of reserves in place	—	—	(1)	(2)	(2)	—	—	(2)
Production	(141)	(101)	(26)	(23)	(291)	(4)	(4)	(299)
Economic revisions due to prices [3]	(106)	(38)	—	(34)	(180)	—	—	(179)
Revisions of prior estimates	18	77	37	4	136	1	(2)	136
Reserves, December 31, 2024	6,313	2,676	356	547	9,892	6	48	9,947
Extensions and discoveries	**—**	**58**	**13**	**7**	**78**	**—**	**—**	**78**
Improved recovery	**1**	**21**	**4**	**32**	**58**	**—**	**—**	**58**
Purchases of reserves in place	**—**	**336**	**57**	**55**	**448**	**—**	**—**	**448**
Sales of reserves in place	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Production	**(167)**	**(112)**	**(31)**	**(35)**	**(345)**	**(3)**	**(1)**	**(349)**
Economic revisions due to prices [3]	**17**	**155**	**10**	**62**	**244**	**—**	**1**	**246**
Revisions of prior estimates	**(261)**	**309**	**10**	**(9)**	**50**	**(3)**	**(9)**	**38**
Reserves, December 31, 2025	**5,903**	**3,443**	**420**	**660**	**10,425**	**—**	**40**	**10,465**
Net Proved Developed Reserves								
December 31, 2022	5,389	582	238	121	6,330	5	34	6,369
December 31, 2023	5,804	610	225	112	6,752	6	30	6,787
December 31, 2024	6,268	629	232	127	7,256	6	25	7,288
December 31, 2025	**5,855**	**1,326**	**258**	**183**	**7,622**	**—**	**25**	**7,647**

(1) Information in the reserves data tables may not add due to rounding.

(2) Bitumen as defined by the SEC, "is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis." Under this definition, all the Company's thermal bitumen, mining bitumen and primary heavy crude oil reserves have been classified as bitumen.

(3) Includes changes due to commodity price and resulting royalty volumes.

2025 total proved Crude Oil and NGLs reserves increased by 518 MMbbl:

- Extensions and discoveries: Increase of 78 MMbbl primarily due to extension drilling/future offset additions at various Bitumen, Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 58 MMbbl primarily due to infill drilling/future offset additions at various natural gas (NGLs), Bitumen and Crude Oil properties as well as improved recovery at Oil Sands Mining and Upgrading (SCO) properties.
- Purchases of reserves in place: Increase of 448 MMbbl primarily due to acquisitions at various Bitumen, Crude Oil and natural gas (NGLs) properties.
- Production: Decrease of 349 MMbbl.
- Economic revisions due to prices: Increase of 246 MMbbl primarily at various Bitumen and Oil Sands Mining and Upgrading (SCO) properties due to lower bitumen pricing, resulting in lower royalties and higher net reserves.
- Revisions of prior estimates: Increase of 38 MMbbl primarily due to improved performance at various Bitumen and Crude Oil properties, partially offset by negative revisions at various natural gas (NGLs), Offshore Africa and North Sea properties, as well as a category transfer at Oil Sands Mining and Upgrading from SCO to Bitumen.

2024 total proved Crude Oil and NGLs reserves increased by 607 MMbbl:

- Extensions and discoveries: Increase of 93 MMbbl primarily due to extension drilling/future offset additions at various Bitumen, natural gas (NGLs) and Crude Oil properties.
- Improved recovery: Increase of 21 MMbbl primarily due to infill drilling/future offset additions at various natural gas (NGLs) and Crude Oil and Bitumen properties as well as improved recovery at Oil Sands Mining and Upgrading (SCO) properties.
- Purchases of reserves in place: Increase of 839 MMbbl primarily due to acquisitions at Oil Sands Mining and Upgrading (SCO) and various natural gas (NGLs) and Crude Oil properties in Alberta.
- Sales of reserves in place: Decrease of 2 MMbbl primarily due to dispositions from various natural gas (NGLs) properties in Alberta.
- Production: Decrease of 299 MMbbl.
- Economic revisions due to prices: Decrease of 179 MMbbl primarily at Oil Sands Mining and Upgrading (SCO) and various Bitumen properties due to higher bitumen pricing resulting in higher royalties and lower net reserves.
- Revisions of prior estimates: Increase of 136 MMbbl primarily due to improved performance at various Bitumen, natural gas (NGLs) and Crude Oil properties as well as transfers from beyond the 50-year reserves life cutoff at Oil Sands Mining and Upgrading (SCO).

2023 total proved Crude Oil and NGLs reserves increased by 639 MMbbl:

- Extensions and discoveries: Increase of 280 MMbbl primarily due to pit extensions at Oil Sands Mining and Upgrading (SCO) and infill drilling/future offset additions at various Bitumen, natural gas (NGLs) and Crude Oil properties.
- Improved recovery: Increase of 75 MMbbl primarily due to infill drilling/future offset additions at various natural gas (NGLs) and Crude Oil properties as well as improved recovery at Oil Sands Mining and Upgrading (SCO) and Bitumen properties.
- Sales of reserves in place: Decrease of 1 MMbbl primarily due to dispositions from various natural gas (NGLs) properties in Alberta.
- Production: Decrease of 298 MMbbl.
- Economic revisions due to prices: Increase of 485 MMbbl primarily at Oil Sands Mining and Upgrading (SCO) and various Bitumen properties due to higher bitumen pricing resulting in higher royalties and lower net reserves.
- Revisions of prior estimates: Increase of 98 MMbbl primarily due to transfers from beyond the 50-year reserves life cutoff at Oil Sands Mining and Upgrading (SCO) and improved performance at various Bitumen properties.

Natural Gas (Bcf) [1]	**North America**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves				
Reserves, December 31, 2022	12,217	4	25	12,246
Extensions and discoveries	1,185	—	—	1,185
Improved recovery	603	—	—	603
Purchases of reserves in place	—	—	—	—
Sales of reserves in place	(6)	—	—	(6)
Production	(750)	(1)	(4)	(755)
Economic revisions due to prices [2]	87	—	1	88
Revisions of prior estimates	57	(1)	1	58
Reserves, December 31, 2023	13,393	3	23	13,419
Extensions and discoveries	202	—	—	202
Improved recovery	152	—	—	152
Purchases of reserves in place	1,090	—	—	1,090
Sales of reserves in place	(44)	—	—	(44)
Production	(765)	(1)	(3)	(769)
Economic revisions due to prices [2]	(3,860)	—	—	(3,860)
Revisions of prior estimates	988	1	(2)	987
Reserves, December 31, 2024	11,155	3	18	11,177
Extensions and discoveries	**105**	**—**	**—**	**105**
Improved recovery	**180**	**—**	**—**	**180**
Purchases of reserves in place	**799**	**—**	**—**	**799**
Sales of reserves in place	**—**	**—**	**—**	**—**
Production	**(900)**	**(1)**	**(2)**	**(903)**
Economic revisions due to prices [2]	**1,667**	**—**	**—**	**1,667**
Revisions of prior estimates	**700**	**(2)**	**(10)**	**688**
Reserves, December 31, 2025	**13,706**	**—**	**6**	**13,712**
Net Proved Developed Reserves				
December 31, 2022	4,956	1	19	4,975
December 31, 2023	4,029	1	10	4,040
December 31, 2024	3,347	3	7	3,357
December 31, 2025	**4,455**	**—**	**2**	**4,457**

(1) Information in the reserves data tables may not add due to rounding.

(2) Includes changes due to commodity price and resulting royalty volumes.

2025 total proved Natural Gas reserves increased by 2,536 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 105 Bcf primarily due to extension drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 180 Bcf primarily due to infill drilling additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 799 Bcf primarily due to acquisitions at various Natural Gas properties in Alberta.
- Production: Decrease of 903 Bcf.
- Economic revisions due to prices: Increase of 1,667 Bcf primarily due to higher natural gas pricing.
- Revisions of prior estimates: Increase of 688 Bcf primarily due to improved performance at various North America Natural Gas properties, partially offset by negative revisions at North Sea and Offshore Africa properties.

2024 total proved Natural Gas reserves decreased by 2,242 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 202 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 152 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 1,090 Bcf primarily due to acquisitions at various Natural Gas properties in Alberta.
- Sales of reserves in place: Decrease of 44 Bcf primarily due to dispositions from various Natural Gas properties in Alberta.
- Production: Decrease of 769 Bcf.
- Economic revisions due to prices: Decrease of 3,860 Bcf primarily due to lower natural gas pricing.
- Revisions of prior estimates: Increase of 987 Bcf primarily due to improved performance at various Natural Gas properties as well as category transfers from probable to proved.

2023 total proved Natural Gas reserves increased by 1,173 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 1,185 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 603 Bcf primarily due to infill drilling/future offsets additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Sales of reserves in place: Decrease of 6 Bcf primarily due to dispositions from various Natural Gas properties in Alberta.
- Production: Decrease of 755 Bcf.
- Economic revisions due to prices: Increase of 88 Bcf primarily at various North America Natural Gas properties due to lower natural gas pricing resulting in lower royalties and higher net reserves.
- Revisions of prior estimates: Increase of 58 Bcf primarily due to category transfers from probable to proved partially offset by negative revisions in various North American core areas as a result of decreased performance.

Capitalized Costs Related to Crude Oil and Natural Gas Activities

	2025			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Proved properties	**$ 153,466**	**$ 9,270**	**$ 5,316**	**$ 168,052**
Unproved properties	**2,651**	**—**	**—**	**2,651**
	156,117	**9,270**	**5,316**	**170,703**
Less: accumulated depletion and depreciation	**(77,557)**	**(9,270)**	**(4,035)**	**(90,862)**
Net capitalized costs	**$ 78,560**	**$ —**	**$ 1,281**	**$ 79,841**

	2024			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 146,309	$ 9,731	$ 5,023	$ 161,063
Unproved properties	2,478	—	48	2,526
	148,787	9,731	5,071	163,589
Less: accumulated depletion and depreciation	(74,775)	(9,392)	(3,885)	(88,052)
Net capitalized costs	$ 74,012	$ 339	$ 1,186	$ 75,537

	2023			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 132,858	$ 8,606	$ 4,409	$ 145,873
Unproved properties	2,108	—	100	2,208
	134,966	8,606	4,509	148,081
Less: accumulated depletion and depreciation	(69,945)	(8,382)	(3,358)	(81,685)
Net capitalized costs	$ 65,021	$ 224	$ 1,151	$ 66,396

Costs Incurred in Crude Oil and Natural Gas Activities

(millions of Canadian dollars)	2025 North America	2025 North Sea	2025 Offshore Africa	2025 Total
Property acquisitions				
Proved	**$ 3,534**	**$ —**	**$ —**	**$ 3,534**
Unproved	**172**	**—**	**—**	**172**
Exploration	**36**	**—**	**(46)**	**(10)**
Development	**4,938**	**1,223**	**547**	**6,708**
Costs incurred	**$ 8,680**	**$ 1,223**	**$ 501**	**$ 10,404**

(millions of Canadian dollars)	2024 North America	2024 North Sea	2024 Offshore Africa	2024 Total
Property acquisitions				
Proved	$ 8,901	$ —	$ —	$ 8,901
Unproved	320	—	—	320
Exploration	102	—	(56)	46
Development	5,543	352	205	6,100
Costs incurred	$ 14,866	$ 352	$ 149	$ 15,367

(millions of Canadian dollars)	2023 North America	2023 North Sea	2023 Offshore Africa	2023 Total
Property acquisitions				
Proved	$ —	$ —	$ —	$ —
Unproved	—	—	—	—
Exploration	43	—	3	46
Development	5,039	558	187	5,784
Costs incurred	$ 5,082	$ 558	$ 190	$ 5,830

Results of Operations from Crude Oil and Natural Gas Producing Activities

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2025, 2024, and 2023 are summarized in the following tables:

	2025			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	**$ 29,490**	**$ 339**	**$ 187**	**$ 30,016**
Production	**(8,260)**	**(469)**	**(79)**	**(8,808)**
Transportation	**(2,716)**	**(10)**	**—**	**(2,726)**
Depletion, depreciation and amortization	**(7,362)**	**(1,573)**	**(432)**	**(9,367)**
Asset retirement obligation accretion	**(307)**	**(64)**	**(9)**	**(380)**
Petroleum revenue tax recovery	**—**	**561**	**—**	**561**
Income tax	**(2,509)**	**486**	**83**	**(1,940)**
Results of operations	**$ 8,336**	**$ (730)**	**$ (250)**	**$ 7,356**

	2024			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	$ 26,501	$ 478	$ 458	$ 27,437
Production	(7,170)	(440)	(109)	(7,719)
Transportation	(2,038)	(10)	(1)	(2,049)
Depletion, depreciation and amortization	(6,089)	(279)	(297)	(6,665)
Asset retirement obligation accretion	(315)	(65)	(9)	(389)
Petroleum revenue tax recovery	—	232	—	232
Income tax	(2,526)	34	(12)	(2,504)
Results of operations	$ 8,363	$ (50)	$ 30	$ 8,343

	2023			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	$ 26,773	$ 442	$ 581	$ 27,796
Production	(7,606)	(342)	(141)	(8,089)
Transportation	(1,550)	(7)	(1)	(1,558)
Depletion, depreciation and amortization	(5,690)	(494)	(213)	(6,397)
Asset retirement obligation accretion	(312)	(46)	(8)	(366)
Petroleum revenue tax recovery	—	273	—	273
Income tax	(2,700)	70	(54)	(2,684)
Results of operations	$ 8,915	$ (104)	$ 164	$ 8,975

Standardized Measure of Discounted Future Net Cash Flows from Proved Crude Oil and Natural Gas Reserves and Changes Therein

The following standardized measure of discounted future net cash flows from proved crude oil and natural gas reserves has been computed using the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, costs as at the balance sheet date and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the crude oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and possible reserves;
- Future production of crude oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future prices and costs rather than 12-month average prices and costs as at the balance sheet date will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration and evaluation expenditures; and
- Future development and asset retirement obligations will differ from those estimated.

Future net revenues, development, production and asset retirement obligation costs have been based upon the estimates referred to above. The following tables summarize the Company's future net cash flows relating to proved crude oil and natural gas reserves based on the standardized measure as prescribed in FASB Topic 932 - "Extractive Activities - Oil and Gas":

	2025			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Future cash inflows	**$ 833,999**	**$ —**	**$ 3,742**	**$ 837,741**
Future production costs	**(296,918)**	**—**	**(997)**	**(297,915)**
Future development costs and asset retirement obligations	**(94,826)**	**—**	**(1,052)**	**(95,878)**
Future income taxes	**(97,315)**	**—**	**(233)**	**(97,548)**
Future net cash flows	**344,940**	**—**	**1,460**	**346,400**
10% annual discount for timing of future cash flows	**(240,827)**	**—**	**(585)**	**(241,412)**
Standardized measure of future net cash flows [(1)]	**$ 104,113**	**$ —**	**$ 875**	**$ 104,988**

(1) In 2025, the Company determined its North Sea reporting jurisdiction was no longer economic and de-booked all related reserves. With no proved reserves remaining, the table no longer includes future net cash flows or its components. Results from operations, income taxes, and asset retirement obligations will continue to be reported in the Company's consolidated financial statements.

	2024			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 876,917	$ 722	$ 5,329	$ 882,968
Future production costs	(286,440)	(414)	(1,661)	(288,515)
Future development costs and asset retirement obligations	(92,455)	(1,970)	(1,804)	(96,229)
Future income taxes	(111,073)	1,144	(413)	(110,342)
Future net cash flows	386,949	(518)	1,451	387,882
10% annual discount for timing of future cash flows	(275,139)	136	(721)	(275,724)
Standardized measure of future net cash flows [(1)]	$ 111,810	$ (382)	$ 730	$ 112,158

(1) Includes abandonment cost estimates for the Ninian field.

	2023			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 863,544	$ 1,067	$ 6,144	$ 870,755
Future production costs	(276,498)	(636)	(1,880)	(279,014)
Future development costs and asset retirement obligations	(86,615)	(1,873)	(1,927)	(90,415)
Future income taxes	(113,516)	967	(508)	(113,057)
Future net cash flows	386,915	(475)	1,829	388,269
10% annual discount for timing of future cash flows	(278,814)	168	(887)	(279,533)
Standardized measure of future net cash flows [1]	$ 108,101	$ (307)	$ 942	$ 108,736

(1) Includes abandonment cost estimates for the Ninian field.

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)	**2025**	2024	2023
Sales of crude oil and natural gas produced, net of production costs	**$ (18,544)**	$ (17,672)	$ (18,174)
Net changes in sales prices and production costs	**(19,233)**	(11,189)	(47,145)
Extensions, discoveries and improved recovery	**3,104**	2,576	8,196
Changes in estimated future development costs	**(890)**	(2,101)	(1,511)
Purchases of proved reserves in place	**5,971**	15,463	—
Sales of proved reserves in place	**—**	(63)	(47)
Revisions of previous reserve estimates	**5,322**	(485)	6,647
Accretion of discount	**14,369**	14,059	17,769
Changes in production timing and other	**671**	2,507	(2,831)
Net change in income taxes	**2,060**	327	8,834
Net change	**(7,170)**	3,422	(28,262)
Balance – beginning of year	**112,158**	108,736	136,998
Balance – end of year	**$ 104,988**	$ 112,158	$ 108,736