



Canadian Natural

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
CO₂	carbon dioxide
CO₂e	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:

Subsidiary:	Jurisdiction of Incorporation	% Ownership
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 accounts 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 authorities 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 CO₂e/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 CO₂e annually until it reaches \$170/tonne of CO₂e 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 CO₂e 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 CO₂e 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 CO₂e annually. Facilities with emissions equal to or greater than 10 kilotonnes CO₂e 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 Albion'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 subsidiaries 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 IOREs 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

(\$ millions)	North America		Offshore Africa		Total Company	
	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

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

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° 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° 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:

- 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.
- 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.
- Thermal Bitumen development plans are designed to optimize the operation and deliver production for the life of the facilities over the next fifty years.
- 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.
- 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.

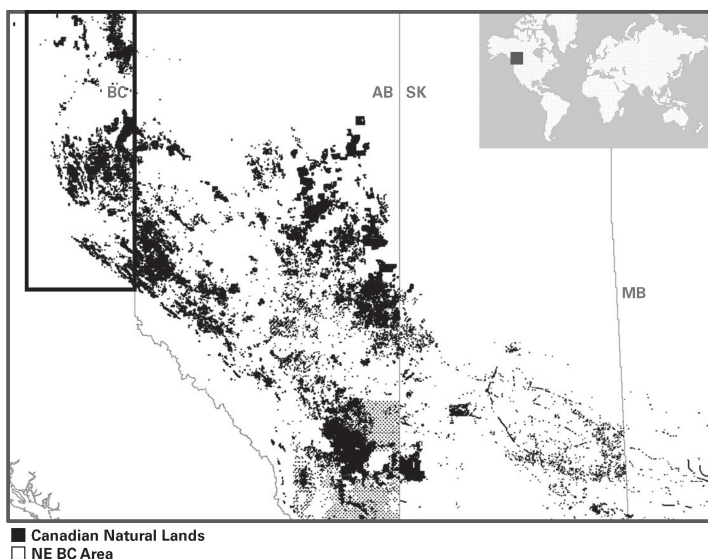
Other Oil and Gas Information

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.

Region	2025 Average Daily Production Rates		2024 Average Daily Production Rates	
	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

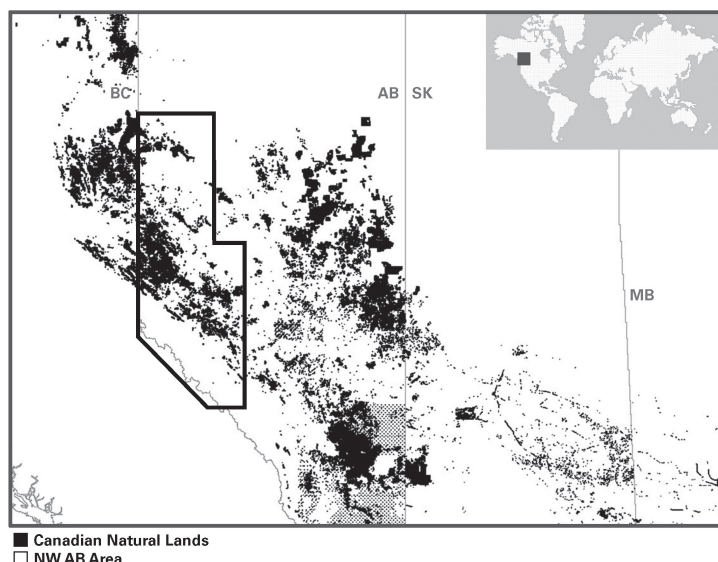


The northeast British Columbia region holds a significant portion of the Montney formation and provides exploration and development opportunities in combination with significant controlled infrastructure. The exploration strategy focuses on comprehensive evaluation through two dimensional seismic, three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

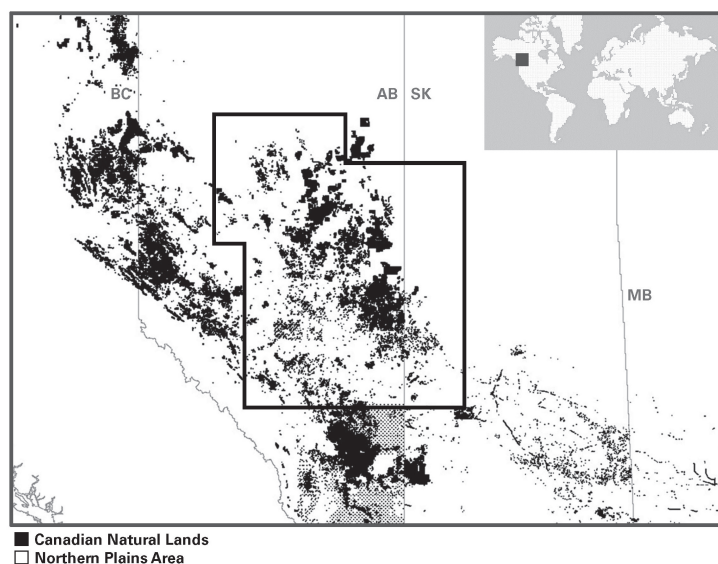
The southern portion of this region encompasses the Company's BC Foothills assets where natural gas is produced from the deep Mississippian and Triassic aged reservoirs in this highly structural area.

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.

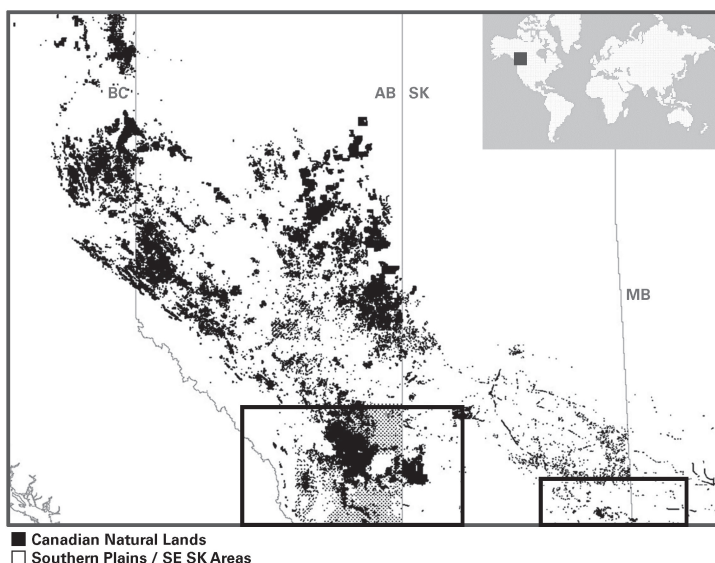
The Company has a 100% interest in the operating thermal SAGD assets at Jackfish and in the Pike lands located adjacent to Jackfish. The infrastructure at Jackfish consists of three processing plants and gathering systems that have a combined capacity of 120,000 bbl/d. Drilling and pipeline development 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

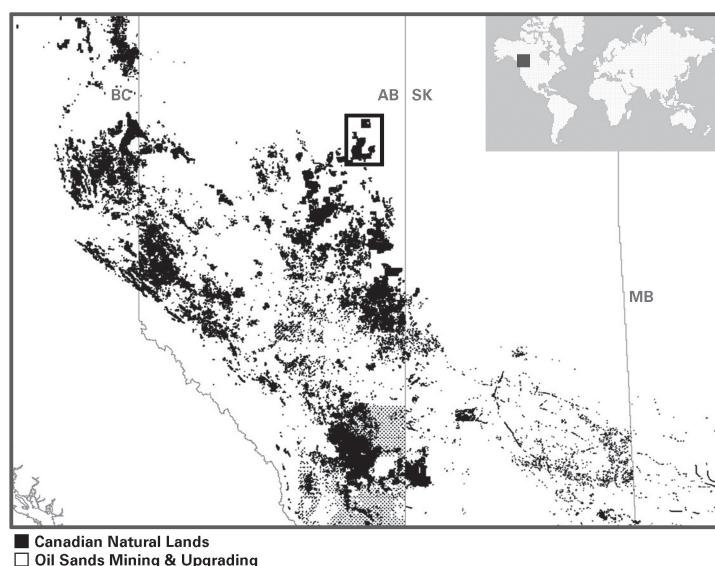
The Southern Plains region is principally located south of the Northern Plains region to the United States border and extending into western Saskatchewan.

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.

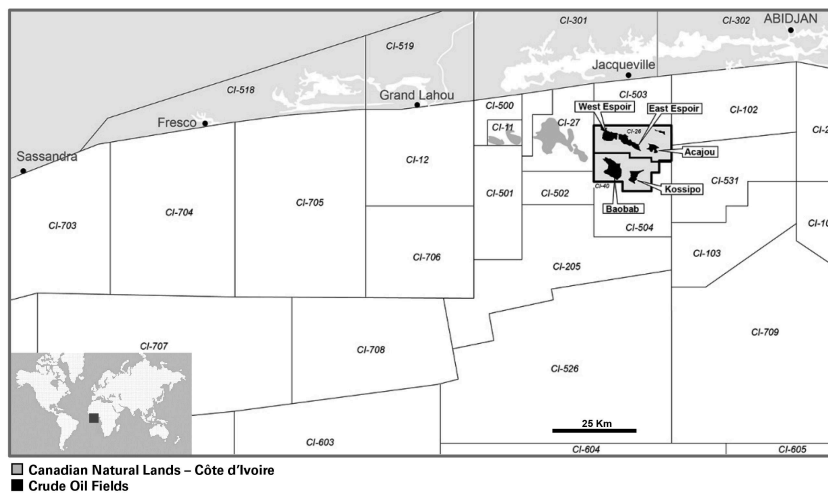
United Kingdom North Sea

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.

Month	2025 Monthly Historical Trading on TSX			
	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 authorizing 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 NRSor 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,

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

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

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

Original Signed By Meghan Klein, P.Eng.

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

**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.