



FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2026

TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED 2026 FIRST QUARTER RESULTS

Canadian Natural's President, Scott Stauth, commented on the Company's first quarter results, "We have a long track record of being an effective and efficient operator, while consistently delivering top tier operational and financial performance through a strong focus on continuous improvement. An example of this performance is our industry-leading Oil Sands Mining and Upgrading Q1/26 operating costs of \$23.73/bbl (US\$17.30/bbl) for our Synthetic Crude Oil ("SCO").

Quarterly production averaged approximately 1,643,000 BOE/d in Q1/26, which included total quarterly liquids production of approximately 1,198,000 bbl/d, 66% of which was SCO, light crude oil and NGLs. We achieved record quarterly North American E&P production for our conventional crude oil and natural gas business of approximately 773,000 BOE/d, consisting of record quarterly liquids production of approximately 329,000 bbl/d and record quarterly natural gas production of 2,668 MMcf/d. Total Company production in Q1/26 delivered year-over-year growth of 4% or approximately 61,000 BOE/d from Q1/25 levels.

Subsequent to quarter end, in April 2026 at our world class Oil Sands Mining and Upgrading assets, we achieved strong monthly production of approximately 630,000 bbl/d and upgrader utilization of 106%. These strong production volumes are high-value, with strong SCO prices at a premium to WTI averaging approximately US\$5.70/bbl on the forward strip for the remainder of 2026.

We remain focused on executing our prudent and capital efficient 2026 capital program as outlined in our updated 2026 guidance previously released in March 2026. Our ability to effectively allocate capital across our strong asset base provides us with a unique competitive advantage and when combined with accretive acquisitions creates significant long-term value for our shareholders."

Canadian Natural's Chief Financial Officer, Victor Darel, added "In Q1/26, we generated adjusted net earnings of \$2.4 billion or \$1.17 per share, and adjusted funds flow of \$4.4 billion or \$2.10 per share. We returned approximately \$1.5 billion directly to our shareholders in Q1/26, including \$1.2 billion in dividends and \$0.3 billion in share repurchases.

As previously announced on March 4, 2026, the Board of Directors increased our quarterly dividend, bringing the annualized dividend up to \$2.50 per common share, marking 2026 as the 26th consecutive year of dividend increases by Canadian Natural, with a compound annual growth rate ("CAGR") of 20% over that time, demonstrating the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline reserves and asset base.

Robust commodity prices in recent months combined with our effective and efficient operations are delivering strong netbacks which accelerates debt reduction, moving our net debt below \$16 billion. As a result, we have increased our pace of share repurchases evident by the \$309 million of share repurchases in April 2026, which we prudently manage on a forward-looking basis. Our next targeted net debt level of \$13 billion approaches faster with increased free cash flow generation, at which time we increase returns to shareholders to 100% of free cash flow."

FIRST QUARTER HIGHLIGHTS

- Generated net earnings of approximately \$1.3 billion and adjusted net earnings from operations of \$2.4 billion.
- Generated adjusted funds flow of approximately \$4.4 billion.
- Direct returns to shareholders totaled approximately \$1.5 billion, comprised of \$1.2 billion in dividends and \$0.3 billion in share repurchases.
 - Year to date, up to and including May 6, 2026, the Company has returned a total of approximately \$3.2 billion directly to shareholders through \$2.5 billion in dividends and \$0.7 billion in share repurchases.
 - 26 consecutive years of dividend growth with a CAGR of 20% over that time.
 - Subsequent to quarter end, declared a quarterly cash dividend on its common shares of \$0.625 per common share.
 - Subsequent to quarter end, share repurchases were significant at approximately \$309 million in April 2026.
- Total quarterly production of approximately 1,643,000 BOE/d, an increase of 61,000 BOE/d or 4% from Q1/25 levels.
 - Quarterly liquids production of approximately 1,198,000 bbl/d, an increase of 24,000 bbl/d or 2% from Q1/25 levels.
 - Record quarterly North American E&P conventional production of approximately 773,000 BOE/d, consisting of record liquids production of approximately 329,000 bbl/d and record natural gas production of 2,668 MMcf/d.
 - Record quarterly Jackfish thermal in situ production of approximately 134,000 bbl/d, driven by strong Pike 1 performance, exceeding nameplate capacity of 120,000 bbl/d.
 - Oil Sands Mining and Upgrading production averaged approximately 588,000 bbl/d of SCO with industry-leading operating costs of \$23.73/bbl (US\$17.30/bbl).
- Canadian Natural continues to progress its defined growth plan over the short, medium, and long-term including:
 - In the short-term, our Conventional E&P assets provide significant highly capital efficient drill to fill development, including continued drilling of liquids-rich assets and heavy crude oil multilateral wells.
 - We are progressing on our medium-term growth projects, with front end engineering in 2026 on both the 30,000 bbl/d Jackfish expansion project and the 70,000 bbl/d Pike 2 project.
 - Further, the Company is progressing long-lead equipment items as part of its thermal in situ growth strategy.
 - In the long-term, we maintain our growth opportunities in our Oil Sands Mining and Upgrading segment that include the 150,000 bbl/d Jackpine Mine expansion at Albion and the 90,000 bbl/d Horizon In-Pit Extraction Plant and Paraffinic Froth Treatment expansion.
 - These projects remain on hold as we wait for greater certainty on more effective and efficient regulatory policies combined with a competitive fiscal framework and egress. When we have that certainty, we will reassess the viability of these projects.

HIGHLIGHTS

(\$ millions, except per common share amounts)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Net earnings	\$ 1,348	\$ 5,303	\$ 2,458
Per common share – basic	\$ 0.65	\$ 2.55	\$ 1.17
– diluted	\$ 0.64	\$ 2.54	\$ 1.17
Adjusted net earnings from operations ⁽¹⁾	\$ 2,446	\$ 1,711	\$ 2,436
Per common share – basic ⁽²⁾	\$ 1.17	\$ 0.82	\$ 1.16
– diluted ⁽²⁾	\$ 1.17	\$ 0.82	\$ 1.16
Cash flows from operating activities	\$ 3,282	\$ 3,768	\$ 4,284
Adjusted funds flow ⁽¹⁾	\$ 4,374	\$ 3,748	\$ 4,530
Per common share – basic ⁽²⁾	\$ 2.10	\$ 1.80	\$ 2.16
– diluted ⁽²⁾	\$ 2.09	\$ 1.79	\$ 2.15
Cash flows used in investing activities	\$ 1,949	\$ 1,200	\$ 1,312
Net capital expenditures ⁽¹⁾	\$ 2,028	\$ 1,237	\$ 1,303
Net capital expenditures ⁽¹⁾ , excluding net acquisitions	\$ 1,255	\$ 1,413	\$ 1,285
Abandonment expenditures	\$ 247	\$ 201	\$ 188
Daily production, before royalties			
Natural gas (MMcf/d)	2,670	2,660	2,451
Crude oil and NGLs (bbl/d)	1,198,079	1,215,364	1,173,804
Equivalent production (BOE/d) ⁽³⁾	1,643,160	1,658,681	1,582,348

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

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

(3) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, or to compare the value ratio using current crude oil and natural gas prices 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.

- Net earnings of approximately \$1.3 billion reflected strong earnings from operations as well as the impacts of share-based compensation, unrealized mark-to-market on the long-term Liquefied Natural Gas ("LNG") agreement, and unrealized foreign exchange on US dollar debt, resulting in adjusted net earnings from operations of \$2.4 billion.

SHAREHOLDER RETURNS

- On March 10, 2026, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 182,396,564 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2026 and ending March 12, 2027, subject to applicable securities laws.
- Year to date, up to and including May 6, 2026, the Company has returned a total of approximately \$3.2 billion directly to shareholders through \$2.5 billion in dividends and \$0.7 billion through the repurchase and cancellation of approximately 11.3 million common shares at a weighted average price of \$60.33 per share.
- On May 6, 2026, the Board of Directors approved a quarterly cash dividend of \$0.625 per common share, payable on July 7, 2026 to shareholders of record at the close of business on June 19, 2026.
 - This dividend represents an annualized dividend of \$2.50 per common share which has grown for 26 consecutive years, demonstrating the confidence that the Board has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline reserves and asset base.

OPERATIONS REVIEW

North America Oil Sands Mining and Upgrading

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Synthetic crude oil production (bbl/d) ⁽¹⁾⁽²⁾	587,946	619,901	595,116

(1) SCO production before royalties and excludes production volumes consumed internally as diesel.

(2) Consists of heavy and light synthetic crude oil products.

- Oil Sands Mining and Upgrading production averaged 587,946 bbl/d of SCO in Q1/26, comparable to Q1/25 levels. Production in Q1/26 reflected third-party natural gas supply restrictions and unplanned maintenance activities, partially offset by the additional working interest in the AOSP mines acquired in Q4/25.
 - Oil Sands Mining and Upgrading operating costs are industry leading, averaging \$23.73/bbl (US\$17.30/bbl) of SCO in Q1/26, an increase of 8% from Q1/25 primarily due to increased maintenance activities.
- At Horizon, the Company is progressing its Naphtha Recovery Unit Tailings Treatment ("NRUTT") project which targets incremental production of approximately 6,300 bbl/d of SCO, following mechanical completion in Q3/27.

North America Exploration and Production

Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Bitumen production (bbl/d)	274,674	266,308	284,706
Net bitumen wells drilled	31	25	18
Net successful bitumen wells drilled	30	24	18
Success rate	97%	96%	100%

- Thermal in situ production averaged 274,674 bbl/d in Q1/26, a decrease of 4% from Q1/25 levels, primarily due to the cyclical nature of Primrose and natural field declines, partially offset by pad additions at Pike 1.
 - Jackfish achieved record quarterly production of 134,396 bbl/d in Q1/26 as a result of strong production from the two new Steam Assisted Gravity Drainage ("SAGD") pads at Pike 1 that continue to exceed expectations.
 - Thermal in situ operating costs averaged \$12.59/bbl (US\$9.18/bbl) in Q1/26, an increase of approximately 12% compared to \$11.23/bbl (US\$7.83/bbl) in Q1/25, primarily due to the cyclic nature of Primrose.
- Subsequent to quarter end, the Company successfully completed a planned turnaround at one of its Jackfish facilities in April 2026, impacting Q2/26 average production by approximately 9,300 bbl/d.
- As part of the Company's defined short-term growth strategy, Canadian Natural has decades of robust capital efficient drill to fill growth opportunities on its long life low decline thermal in situ assets, which we continue to develop in a disciplined manner to deliver safe and reliable thermal in situ production.
 - At Pike 1, the second new pad came on production in late-March 2026 and continues to ramp up. Current combined production from the two new Pike 1 pads is approximately 44,000 bbl/d and continues to exceed expectations, with a Steam to Oil Ratio ("SOR") of approximately 1.8x.
 - As a result of strong performance from the Pike 1 pads and through facility optimization including pipeline interconnectivity and debottlenecking, Jackfish is exceeding its facility nameplate capacity of 120,000 bbl/d by approximately 14,000 bbl/d on average in the quarter.
 - At Primrose, the Company completed drilling a Cyclic Steam Stimulation ("CSS") pad in February 2026 with production targeted to come on in Q3/26. The Company is drilling two additional CSS pads which are targeted to come on production in 2027.
 - At Kirby, the Company is planning to commence drilling a SAGD pad in mid-May 2026, which is targeted to come on production in 2027.
- As part of Canadian Natural's defined medium-term growth strategy, front end engineering is progressing in 2026 on both the 30,000 bbl/d Jackfish expansion project and the 70,000 bbl/d Pike 2 growth project.

- The Company is progressing long-lead equipment items as part of its thermal in situ growth strategy.
- Canadian Natural has been piloting solvent enhanced oil recovery technology on certain thermal in situ assets with an objective to increase bitumen production while reducing the SOR and Greenhouse Gas ("GHG") emissions, at the same time optimizing solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
- The Company continues to operate the commercial scale solvent SAGD pad at Kirby North and the solvent enhanced steam flood pilot at Primrose. An additional solvent SAGD pilot at Kirby South is targeting to begin injection in Q2/26 to evaluate additional future commercial development opportunities.

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Crude oil and NGLs production (bbl/d)	328,591	319,189	276,532
Net crude oil wells drilled	83	90	57
Net successful crude oil wells drilled	83	90	56
Success rate	100%	100%	98%

- Record North America E&P liquids production, excluding thermal in situ, of 328,591 bbl/d was achieved in Q1/26, an increase of 19% or approximately 52,000 bbl/d from Q1/25 levels. This record reflects opportunistic acquisitions completed in 2025 and Q1/26, and strong organic growth from heavy crude oil multilaterals, light crude oil and NGLs, partially offset by natural field declines.
 - Primary heavy crude oil production averaged 93,824 bbl/d in Q1/26, an increase of 10% or approximately 8,200 bbl/d from Q1/25 levels, reflecting strong drilling results from the Company's multilateral wells.
 - Canadian Natural's highly successful multilateral drilling program continues to unlock opportunity on our 3 million net acres of high quality, multizone land throughout our primary heavy crude oil assets.
 - Operating costs in the Company's primary heavy crude oil operations averaged \$16.13/bbl (US\$11.76/bbl) in Q1/26, a decrease of 11% from Q1/25 levels, primarily reflecting lower operating cost multilateral production.
 - Pelican Lake production averaged 40,548 bbl/d in Q1/26, a decrease of 6% from Q1/25 levels, reflecting the low natural field declines from this long life low decline polymer flood asset.
 - Operating costs at Pelican Lake averaged \$10.31/bbl (US\$7.52/bbl) in Q1/26, an increase of 6% over Q1/25 levels primarily due to lower production volumes.
 - Record quarterly production of 194,219 bbl/d was achieved in North America light crude oil and NGLs in Q1/26, an increase of 31% or approximately 46,000 bbl/d from Q1/25 levels, primarily reflecting acquisitions and strong drilling results.
 - Operating costs in the Company's North America light crude oil and NGLs operations averaged \$12.73/bbl (US\$9.28/bbl) in Q1/26, a decrease of 3% from Q1/25 levels, primarily reflecting higher production volumes.

North America Natural Gas

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Natural gas production (MMcf/d)	2,668	2,657	2,436
Net natural gas wells drilled	24	20	19
Net successful natural gas wells drilled	24	20	19
Success rate	100%	100%	100%

- Record quarterly North America natural gas production averaging 2,668 MMcf/d was achieved in Q1/26, an increase of 10% from Q1/25 levels, primarily reflecting acquisitions completed in 2025 and Q1/26, partially offset by natural field declines. North America natural gas operating costs averaged \$1.23/Mcf in Q1/26.

International Exploration and Production

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Crude oil production (bbl/d)	6,868	9,966	17,450
Natural gas production (MMcf/d)	2	3	15

- International E&P crude oil production volumes averaged 6,868 bbl/d in Q1/26, a decrease of 61% compared to Q1/25 levels. The decrease reflected the temporary suspension of production at Baobab in Offshore Africa due to planned maintenance on its floating production storage and offloading ("FPSO") vessel, which is expected to return to service in early June 2026, planned North Sea abandonments conducted as part of the previously announced decommissioning activities and maintenance.

Drilling Activity

	Three Months Ended			
	March 31, 2026		March 31, 2025	
(number of wells)	Gross	Net	Gross	Net
Crude oil ⁽¹⁾	118	113	75	74
Natural gas	30	24	23	19
Dry	1	1	1	1
Subtotal	149	138	99	94
Stratigraphic test / service wells	540	540	484	462
Total	689	678	583	556
Success rate (excluding stratigraphic test / service wells)		99%		99%

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 138 net crude oil and natural gas wells in Q1/26, 44 more than in Q1/25.

MARKETING

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Benchmark Commodity Prices			
WTI benchmark price (US\$/bbl) ⁽¹⁾	\$ 72.17	\$ 59.13	\$ 71.42
WCS heavy differential (discount) to WTI (US\$/bbl) ⁽¹⁾	\$ (14.12)	\$ (11.20)	\$ (12.66)
WCS heavy differential as a percentage of WTI (%) ⁽¹⁾	20%	19%	18%
Condensate benchmark price (US\$/bbl)	\$ 71.65	\$ 57.01	\$ 69.89
SCO price (US\$/bbl) ⁽¹⁾	\$ 71.75	\$ 57.78	\$ 69.07
SCO premium (discount) to WTI (US\$/bbl) ⁽¹⁾	\$ (0.42)	\$ (1.35)	\$ (2.35)
AECO benchmark price (C\$/GJ)	\$ 2.36	\$ 2.22	\$ 1.92
Realized Prices			
Exploration & Production liquids realized price (C\$/bbl) ⁽²⁾⁽³⁾⁽⁴⁾⁽⁵⁾	\$ 76.02	\$ 64.42	\$ 79.85
SCO realized price (C\$/bbl) ⁽¹⁾⁽³⁾⁽⁴⁾⁽⁵⁾	\$ 89.68	\$ 75.90	\$ 95.52
Natural gas realized price (C\$/Mcf) ⁽⁴⁾	\$ 3.32	\$ 2.89	\$ 3.13

(1) West Texas Intermediate ("WTI"); Western Canadian Select ("WCS"); Synthetic Crude Oil ("SCO").

(2) Exploration & Production crude oil and NGLs average realized price excludes SCO.

(3) Pricing is net of blending and feedstock costs.

(4) Excludes risk management activities.

(5) Non-GAAP ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A.

- Canadian Natural has a balanced and diverse product mix of SCO, light crude oil, NGLs, heavy crude oil, bitumen and natural gas, complemented with a balanced and diverse marketing strategy.
 - Approximately 789,000 bbl/d or 66% of total liquids production in Q1/26 is SCO, light crude oil and NGLs.
 - Current SCO annual average strip pricing in 2026 represents an average premium to WTI of approximately \$3.75/bbl.
- Canadian Natural has total contracted crude oil transportation capacity of 256,500 bbl/d, consisting of committed volumes to Canada's west coast and to the United States Gulf Coast, being approximately 21% of 2026 forecasted liquids production. The egress supports Canadian Natural's long-term sales strategy by targeting diverse refining markets which drive stronger netbacks while also reducing exposure to egress constraints.
- The North West Redwater refinery, 50% owned by the Company, primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 94,351 bbl/d in Q1/26.
- Canadian Natural has a diversified natural gas marketing strategy with the Company in 2026 to consume the equivalent of approximately 31% of forecasted natural gas production in its Oil Sands Mining and Upgrading and thermal operations, with approximately 37% targeted to be sold at AECO/Station 2 pricing, and approximately 32% targeted to be exported to other North American and international markets capturing higher natural gas prices, maximizing value.
- Canadian Natural has a long-term natural gas supply agreement with Cheniere Marketing, LLC. ("Cheniere") as part of the Sabine Pass Liquefaction Expansion Project where the Company has agreed to sell 140,000 MMBtu/d of natural gas to Cheniere for a term of 15 years, with delivery anticipated to begin in 2030.
 - Under the terms of the agreement, Canadian Natural will deliver natural gas to Cheniere in Chicago and receive a Japan Korea Marker ("JKM") index price less deductions for transportation and liquefaction.

ADVISORY

Special Note Regarding Non-GAAP and Other Financial Measures

This document includes references to non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure ("NI 52-112"). These financial measures are used by the Company to evaluate its financial performance, financial position, and cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS Accounting Standards and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this document and the Company's MD&A and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below as well as in the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A for the three months ended March 31, 2026 dated May 6, 2026.

Free Cash Flow Allocation Policy

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, pay returns to shareholders and to repay or maintain net debt levels, pursuant to the free cash flow allocation policy.

The Company's free cash flow is used to determine the targeted amount of shareholder returns after dividends. The amount allocated to shareholders varies depending on the Company's net debt position.

Free cash flow is calculated as adjusted funds flow less dividends on common shares, net capital expenditures and abandonment expenditures. The Company targets to manage the allocation of free cash flow on a forward-looking annual basis, while managing working capital and cash requirements as needed.

In March 2026, the Board of Directors adjusted the allocation of free cash flow, effective January 1, 2026, as follows:

- When net debt is at or above \$16 billion, 60% of free cash flow will be allocated to direct shareholder returns in the form of share repurchases and 40% to the balance sheet.
- When net debt is between \$13 billion and \$16 billion, 75% of free cash flow will be allocated to direct shareholder returns in the form of share repurchases and 25% to the balance sheet.
- When net debt is at or below \$13 billion, 100% of free cash flow will be allocated to direct shareholder returns in the form of share repurchases.

The Company's free cash flow for the three months ended March 31, 2026 and comparable periods is shown below:

(\$ millions)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Adjusted funds flow ⁽¹⁾	\$ 4,374	\$ 3,748	\$ 4,530
Less: Dividends on common shares	1,224	1,226	1,184
Net capital expenditures ⁽¹⁾	2,028	1,237	1,303
Abandonment expenditures	247	201	188
Free cash flow	\$ 875	\$ 1,084	\$ 1,855

(1) Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A for the three months ended March 31, 2026 dated May 6, 2026.

Long-term Debt, net

Long-term debt, net (also referred to as net debt) is a capital management measure that is calculated as current and long-term debt less cash and cash equivalents.

(\$ millions)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Long-term debt	\$ 16,961	\$ 16,617	\$ 17,428
Less: cash and cash equivalents	808	673	93
Long-term debt, net	\$ 16,153	\$ 15,944	\$ 17,335

Breakeven WTI Price

The breakeven WTI price is a supplementary financial measure that represents the equivalent US dollar WTI price per barrel where the Company's adjusted funds flow is equal to the sum of maintenance capital and dividends. The Company considers the breakeven WTI price a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. The breakeven WTI price incorporates the non-GAAP financial measure adjusted funds flow as reconciled in the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A. Maintenance capital is a supplementary financial measure that represents the capital required to maintain annual production at prior period levels.

Capital Budget

Capital budget (or capital forecast) is a forward-looking non-GAAP financial measure. Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns, and the balancing of project risks and time horizons.

The capital budget (or capital forecast) excludes abandonment expenditures related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea. The Company currently carries an Asset Retirement Obligation ("ARO") liability on its balance sheet for these forecasted future expenditures. Abandonment expenditures are reported before the impact of current income tax recoveries in Canada and the UK portion of the North Sea. The Company is eligible to recover interest related to tax recoveries in the North Sea.

Capital Efficiency

Capital efficiency is a supplementary financial measure that represents the capital spent to add new or incremental production divided by the current rate of the new or incremental production. It is expressed as a dollar amount per flowing volume of a product (\$/bbl/d or \$/BOE/d). The Company considers capital efficiency a key measure in evaluating its performance, as it demonstrates the efficiency of the Company's capital investments.

MANAGEMENT'S DISCUSSION AND ANALYSIS

ADVISORY

Special Note Regarding Forward-Looking Statements

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

The forward-looking statements are based on current expectations, estimates, and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance, or achievements of the Company to be materially different from any future results, performance, or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+"), the impact of conflicts in the Middle East, in Ukraine and in Venezuela, the restriction or disruption of global trade routes, the impact of changes to US economic policy, increased inflation, and the risk of decreased economic activity resulting from a global recession) which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil, natural gas and NGLs prices; the impact of the ramp-up of LNG Canada on commodity prices; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; changes and uncertainties in the international trade environment, including with respect to tariffs, export restrictions, embargoes, and key trade agreements (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded); uncertainty in the regulatory framework governing greenhouse gas 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 Memorandum of Understanding ("MOU") entered into between the Government of Canada and the Government of Alberta in November 2025; civil unrest and political uncertainty, including changes in government, actions of or against terrorists, insurgent groups, or other conflict including conflict between states; the ability of the Company to prevent and recover from a cyberattack, other cyber-related crime, and other cyber-related incidents; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling, and other equipment; ability of the Company to complete capital programs; the Company's ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting, or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in the mining, extracting, or upgrading of the Company's bitumen products; availability and cost of financing; the Company's success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; changes to future abandonment and decommissioning costs; actions by governmental authorities; government regulations and the expenditures

required to comply with them (especially safety, competition, environmental laws and regulations, and the impact of climate change initiatives on capital expenditures and production expenses); interpretations of applicable tax and competition laws and regulations; asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short-, medium-, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; the impact of legal proceedings to which the Company is party; and other circumstances affecting revenues and expenses.

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

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

Special Note Regarding Non-GAAP and Other Financial Measures

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

Special Note Regarding Amendments to the *Competition Act* (Canada)

On June 20, 2024, amendments to the *Competition Act* (Canada) came into force with the adoption of Bill C-59, *An Act to Implement Certain Provisions of the Fall Economic Statement*, which impact environmental and climate disclosures by businesses. As a result of these amendments, certain public representations by a business regarding the benefits of the work it is doing to protect or restore the environment or mitigate the environmental and ecological causes or effects of climate change may violate the *Competition Act*'s deceptive marketing practices provisions. Subsequently, on March 26, 2026, the *Competition Act* was further amended to remove the requirement that businesses substantiate their environmental representations about a business or business activity based on an internationally recognized methodology, and eliminate private rights of action under the revised business-activity greenwashing provision. Notwithstanding these amendments, uncertainty surrounding the interpretation and enforcement of this legislation, which includes any future amendments, may expose the Company to increased litigation and financial penalties, the outcome and impacts of which can be difficult to assess or quantify and may have a material adverse effect on the Company's business, reputation, financial condition, and results.

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the Company's unaudited interim consolidated financial statements (the "financial statements") for the three months ended March 31, 2026, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2025. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three months ended March 31, 2026 and this MD&A have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards").

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

The following discussion and analysis refers primarily to the Company's financial results for the three months ended March 31, 2026 in relation to the first quarter of 2025 and the fourth quarter of 2025. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2025, is available on SEDAR+ at www.sedarplus.ca, and on EDGAR at www.sec.gov. Information in such Annual Information Form and on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated May 6, 2026.

FINANCIAL HIGHLIGHTS

(\$ millions, except per common share amounts)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Product sales ⁽¹⁾	\$ 12,404	\$ 10,710	\$ 12,712
Crude oil and NGLs	\$ 11,114	\$ 9,666	\$ 11,732
Natural gas	\$ 832	\$ 735	\$ 716
Net earnings	\$ 1,348	\$ 5,303	\$ 2,458
Per common share – basic	\$ 0.65	\$ 2.55	\$ 1.17
– diluted	\$ 0.64	\$ 2.54	\$ 1.17
Adjusted net earnings from operations ⁽²⁾	\$ 2,446	\$ 1,711	\$ 2,436
Per common share – basic ⁽³⁾	\$ 1.17	\$ 0.82	\$ 1.16
– diluted ⁽³⁾	\$ 1.17	\$ 0.82	\$ 1.16
Cash flows from operating activities	\$ 3,282	\$ 3,768	\$ 4,284
Adjusted funds flow ⁽²⁾	\$ 4,374	\$ 3,748	\$ 4,530
Per common share – basic ⁽³⁾	\$ 2.10	\$ 1.80	\$ 2.16
– diluted ⁽³⁾	\$ 2.09	\$ 1.79	\$ 2.15
Cash flows used in investing activities	\$ 1,949	\$ 1,200	\$ 1,312
Net capital expenditures ⁽²⁾	\$ 2,028	\$ 1,237	\$ 1,303
Abandonment expenditures	\$ 247	\$ 201	\$ 188

(1) Further details related to product sales are disclosed in note 16 to the financial statements.

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

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

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings and Adjusted Net Earnings from Operations

Net earnings for the first quarter of 2026 were \$1,348 million compared with \$2,458 million for the first quarter of 2025 and \$5,303 million for the fourth quarter of 2025. Net earnings for the first quarter of 2026 included non-operating losses, net of tax, of \$1,098 million compared with non-operating income of \$22 million for the first quarter of 2025 and non-operating income of \$3,592 million for the fourth quarter of 2025 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on financing activities, and the gain on acquisition, disposition, and remeasurement, and recoverability charges related to the North Sea and Offshore Africa recorded in the fourth quarter of 2025. Excluding these items, adjusted net earnings from operations for the first quarter of 2026 were \$2,446 million compared with \$2,436 million for the first quarter of 2025 and \$1,711 million for the fourth quarter of 2025. Further details related to the movements in adjusted net earnings from operations are discussed in the 'Non-GAAP and Other Financial Measures' section of this MD&A.

The movements in net earnings and adjusted net earnings from operations for the first quarter of 2026 from the first quarter of 2025 primarily reflected:

- higher crude oil and NGLs sales volumes in the North America Exploration and Production segment; and
 - higher natural gas sales volumes and realized pricing in the North America Exploration and Production segment;
- partially offset by:
- lower realized crude oil and NGLs pricing ⁽¹⁾ in the North America Exploration and Production segment; and
 - lower realized SCO pricing ⁽¹⁾ and sales volumes in the Oil Sands Mining and Upgrading segment.

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

The movements in net earnings and adjusted net earnings from operations for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected:

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

partially offset by:

- lower sales volumes in the Oil Sands Mining and Upgrading segment.

The impacts of depletion, depreciation and amortization, share-based compensation, risk management activities, foreign exchange loss (gain), and the gain on acquisition, disposition, and remeasurement, and recoverability charges related to the North Sea and Offshore Africa recorded in the fourth quarter of 2025 also contributed to the movements in net earnings from the comparable periods. These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the first quarter of 2026 were \$3,282 million compared with \$4,284 million for the first quarter of 2025 and \$3,768 million for the fourth quarter of 2025. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted related to the fluctuations in adjusted net earnings from operations, together with the impact of net changes in non-cash working capital.

Adjusted funds flow for the first quarter of 2026 was \$4,374 million compared with \$4,530 million for the first quarter of 2025 and \$3,748 million for the fourth quarter of 2025. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above related to the fluctuations in cash flows from operating activities, excluding the impact of the net change in non-cash working capital, abandonment expenditures, and movements in other long-term assets, including the unamortized cost of contributions to the Company's employee bonus program, interest on Petroleum Revenue Tax ("PRT") recoveries, and prepaid cost of service tolls. Further details related to the movements in adjusted funds flow are discussed in the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Production Volumes

Crude oil and NGLs production before royalties for the first quarter of 2026 of 1,198,079 bbl/d was comparable with 1,173,804 bbl/d for the first quarter of 2025 and 1,215,364 bbl/d for the fourth quarter of 2025. Natural gas production before royalties for the first quarter of 2026 of 2,670 MMcf/d increased 9% from 2,451 MMcf/d for the first quarter of 2025 and was comparable with 2,660 MMcf/d for the fourth quarter of 2025. Total production before royalties for the first quarter of 2026 of 1,643,160 BOE/d increased 4% from 1,582,348 BOE/d for the first quarter of 2025 and was comparable with 1,658,681 BOE/d for the fourth quarter of 2025. Crude oil and NGLs and natural gas production volumes are discussed in detail in the 'Daily Production, before royalties' section of this MD&A.

Product Prices

In the Company's Exploration and Production segments, realized crude oil and NGLs prices averaged \$76.02 per bbl for the first quarter of 2026, a decrease of 5% from \$79.85 per bbl for the first quarter of 2025 and an increase of 18% from \$64.42 per bbl for the fourth quarter of 2025. The realized natural gas price increased 6% to average \$3.32 per Mcf for the first quarter of 2026 from \$3.13 per Mcf for the first quarter of 2025 and increased 15% from \$2.89 per Mcf for the fourth quarter of 2025. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price decreased 6% to average \$89.68 per bbl for the first quarter of 2026 from \$95.52 per bbl for the first quarter of 2025 and increased 18% from \$75.90 per bbl for the fourth quarter of 2025. The Company's realized product pricing is reflective of the prevailing benchmark pricing. Crude oil and NGLs and natural gas prices are discussed in detail in the 'Business Environment', 'Realized Product Prices – Exploration and Production', and 'Realized Product Prices, Royalties and Transportation – Oil Sands Mining and Upgrading' sections of this MD&A.

Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense⁽¹⁾ averaged \$13.54 per bbl for the first quarter of 2026, a decrease of 14% from \$15.74 per bbl for the first quarter of 2025 and a decrease of 6% from \$14.35 per bbl for the fourth quarter of 2025. Natural gas production expense⁽¹⁾ averaged \$1.24 per Mcf for the first quarter of 2026, an increase of 3% from \$1.20 per Mcf for the first quarter of 2025 and an increase of 13% from \$1.10 per Mcf for the fourth quarter of 2025. In the Oil Sands Mining and Upgrading segment, production expense⁽¹⁾ averaged \$23.73 per bbl for the first quarter of 2026, an increase of 8% from \$21.88 per bbl for the first quarter of 2025 and an increase of 9% from \$21.84 per bbl for the fourth quarter of 2025. Crude oil and NGLs and natural gas production expense is discussed in detail in the 'Production Expense – Exploration and Production' and 'Production Expense – Oil Sands Mining and Upgrading' sections of this MD&A.

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

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

(\$ millions, except per common share amounts)	Mar 31 2026	Dec 31 2025	Sep 30 2025	Jun 30 2025
Product sales ⁽¹⁾	\$ 12,404	\$ 10,710	\$ 11,070	\$ 9,675
Crude oil and NGLs	\$ 11,114	\$ 9,666	\$ 10,468	\$ 8,874
Natural gas	\$ 832	\$ 735	\$ 399	\$ 600
Net earnings	\$ 1,348	\$ 5,303	\$ 600	\$ 2,459
Net earnings per common share				
– basic	\$ 0.65	\$ 2.55	\$ 0.29	\$ 1.17
– diluted	\$ 0.64	\$ 2.54	\$ 0.29	\$ 1.17
(\$ millions, except per common share amounts)	Mar 31 2025	Dec 31 2024	Sep 30 2024	Jun 30 2024
Product sales ⁽¹⁾	\$ 12,712	\$ 11,064	\$ 10,401	\$ 10,622
Crude oil and NGLs	\$ 11,732	\$ 10,381	\$ 9,943	\$ 10,084
Natural gas	\$ 716	\$ 451	\$ 257	\$ 331
Net earnings	\$ 2,458	\$ 1,138	\$ 2,266	\$ 1,715
Net earnings per common share				
– basic	\$ 1.17	\$ 0.54	\$ 1.07	\$ 0.80
– diluted	\$ 1.17	\$ 0.54	\$ 1.06	\$ 0.80

(1) Further details related to product sales for the three months ended March 31, 2026 and 2025 are disclosed in note 16 to the financial statements.

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

- **Crude oil pricing** – Fluctuations in global supply/demand including crude oil production levels from OPEC+ and its impact on world supply, the impact of geopolitical and market uncertainties (including those due to the conflicts in the Middle East and in Ukraine, the restriction or disruption of global trade routes, and the impacts of ongoing tariff and trade uncertainty) on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the start-up of the Trans Mountain Expansion ("TMX") pipeline in the second quarter of 2024, the impact of increased supply of heavy crude oil from Venezuela, the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America, and the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the International segments.
- **Natural gas pricing** – Fluctuations in both the demand for natural gas and inventory storage levels, the impact of third-party pipeline maintenance and outages, the impact of geopolitical and market uncertainties, the impact of seasonal conditions, the impact of liquefied natural gas ("LNG") demand and exports, and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production from Kirby and Jackfish, fluctuations in production due to the cyclic nature of Primrose, fluctuations in the Company's drilling program in the North America Exploration and Production segment, natural field declines, the impact of turnarounds in the Oil Sands Mining and Upgrading segment, the impact and timing of acquisitions (including the acquisition of working interests in AOSP and Duvernay assets in the fourth quarter of 2024, the acquisition of assets in the Palliser Block in the second quarter of 2025, the acquisition of assets in the Grande Prairie area in the third quarter of 2025, the AOSP asset swap in the fourth quarter of 2025, and the acquisition of assets in the Peace River area in the first quarter of 2026), wildfires, and maintenance activities in the North America Exploration and Production segment. Sales volumes in the International segments also reflected fluctuations due to the timing of liftings, planned abandonment activities in the North Sea, and temporary suspension of production at Baobab in Offshore Africa for planned floating production, storage and offloading vessel ("FPSO") maintenance.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's drilling program in the North America Exploration and Production segment, the impact and timing of acquisitions (including the acquisition of a working interest in the Duvernay assets in the fourth quarter of 2024, the acquisition of assets in the Palliser Block in the second quarter of 2025, the acquisition of assets in the Grande Prairie area in the third quarter of 2025, and the acquisition of assets in the Peace River area in the first quarter of 2026), natural field declines, the impact of seasonal conditions, and wildfires in the North America Exploration and Production segment.

- **Production expense** – Fluctuations primarily due to the impacts of the demand and cost for services, fluctuations in product mix and production volumes, seasonal conditions, carbon tax, fluctuating energy costs, inflationary cost pressures, cost optimizations across all segments, turnarounds in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Depletion, depreciation and amortization expense** – Fluctuations due to changes in sales volumes, timing of acquisitions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, the impact of turnarounds in the Oil Sands Mining and Upgrading segment, the impact on the depletable base resulting from the gain recognized on the AOSP mine assets, and recoverability charges related to the North Sea and Offshore Africa.
- **Share-based compensation** – Fluctuations due to the measurement of fair market value of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Interest expense** – Fluctuations due to changing long-term debt levels and lease liabilities, the impact of movements in benchmark interest rates on outstanding floating rate long-term debt, and interest on PRT recoveries.
- **Foreign exchange** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt and working capital.
- **Gain on acquisitions, disposition, and remeasurement** – Fluctuations due to gain on acquisitions, representing the excess of the fair value of the net assets acquired compared to total purchase consideration and previously held interests, a gain on remeasurement to fair value of the Company's pre-existing 90% interest in the AOSP mines and a gain on disposition of the 10% interest in Scotford and Quest disposed of as part of the AOSP asset swap in the fourth quarter of 2025.

BUSINESS ENVIRONMENT

Global crude oil benchmark pricing rebounded during the first quarter of 2026 as conflict in the Middle East heightened market concerns regarding potential supply disruptions. While underlying global supply growth continued to outpace demand growth, escalation of regional conflict contributed to increased price volatility and a higher risk premium entering into 2026. Crude oil pricing is expected to remain elevated in the near term amid ongoing geopolitical uncertainty, with prices anticipated to stabilize as conflict-related risks subside and supply-demand fundamentals reassert themselves. Natural gas benchmark pricing remained supported during the first quarter of 2026, driven by winter seasonal demand and continued strength in LNG export activity from the US Gulf Coast. In Canada, AECO benchmark pricing improved due to strong export demand from the Western Canadian Sedimentary Basin ("WCSB"). The continued ramp-up of LNG Canada is expected to further increase LNG demand and provide incremental support to AECO pricing through 2026.

Benchmark Commodity Prices

(Average for the period)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
WTI benchmark price (US\$/bbl)	\$ 72.17	\$ 59.13	\$ 71.42
Dated Brent benchmark price (US\$/bbl)	\$ 80.93	\$ 63.69	\$ 75.68
WCS Heavy Differential from WTI (US\$/bbl)	\$ 14.12	\$ 11.20	\$ 12.66
SCO price (US\$/bbl)	\$ 71.75	\$ 57.78	\$ 69.07
Condensate benchmark price (US\$/bbl)	\$ 71.65	\$ 57.01	\$ 69.89
NYMEX benchmark price (US\$/MMBtu)	\$ 4.96	\$ 3.55	\$ 3.66
AECO benchmark price (C\$/GJ)	\$ 2.36	\$ 2.22	\$ 1.92
US/Canadian dollar average exchange rate (US\$)	\$ 0.7290	\$ 0.7170	\$ 0.6969

Substantially all of the Company's production is sold based on US dollar benchmark pricing, with crude oil marketed based on WTI and Brent indices, and natural gas marketed using a diversified mix of AECO- and NYMEX-based pricing. The Company's realized prices are directly impacted by fluctuations in foreign exchange rates, which affect product revenues as Canadian dollar sales prices change relative to the US dollar benchmark prices.

Crude Oil

Crude oil sales contracts in North America are typically based on WTI benchmark pricing. WTI averaged US\$72.17 per bbl for the first quarter of 2026, comparable with US\$71.42 per bbl for the first quarter of 2025 and an increase of 22% from US\$59.13 per bbl for the fourth quarter of 2025.

Crude oil sales contracts for the Company's International segments are typically based on Brent benchmark pricing, which is representative of international markets and overall global supply and demand. Brent averaged US\$80.93 per bbl for the first quarter of 2026, an increase of 7% from US\$75.68 per bbl for the first quarter of 2025 and an increase of 27% from US\$63.69 per bbl for the fourth quarter of 2025.

The increase in WTI and Brent benchmark pricing for the first quarter of 2026 from the comparable periods primarily reflected the conflict in the Middle East and resulting global supply disruptions. Early in the first quarter of 2026, pricing was also supported by supply constraints following severe US weather.

The WCS Heavy Differential averaged US\$14.12 per bbl for the first quarter of 2026, compared with US\$12.66 per bbl for the first quarter of 2025 and US\$11.20 per bbl for the fourth quarter of 2025. The widening of the WCS Heavy Differential for the first quarter of 2026 from the comparable periods primarily reflected lower US Gulf Coast heavy oil pricing resulting from increased availability of Venezuelan heavy crude oil, partially offset by a tightening of the sour crude market due to Middle East disruptions.

SCO pricing averaged US\$71.75 per bbl for the first quarter of 2026, an increase of 4% from US\$69.07 per bbl for the first quarter of 2025 and an increase of 24% from US\$57.78 per bbl for the fourth quarter of 2025. The increase in SCO pricing for the first quarter of 2026 from the first quarter of 2025 primarily reflected a strengthening of the SCO differential during the first quarter of 2026 due to stronger refinery demand. The increase in SCO pricing for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected stronger WTI benchmark pricing.

Natural Gas

NYMEX benchmark pricing averaged US\$4.96 per MMBtu for the first quarter of 2026, an increase of 36% from US\$3.66 per MMBtu for the first quarter of 2025 and an increase of 40% from US\$3.55 per MMBtu for the fourth quarter of 2025. The increase in NYMEX natural gas pricing for the first quarter of 2026 from the comparable periods primarily reflected increased heating demand and weather-related outages following severe winter storms early in the first quarter of 2026 in the Eastern US, combined with sustained strength in global LNG demand and exports out of the US Gulf Coast.

AECO benchmark pricing averaged \$2.36 per GJ for the first quarter of 2026, an increase of 23% from \$1.92 per GJ for the first quarter of 2025 and an increase of 6% from \$2.22 per GJ for the fourth quarter of 2025. The increase in AECO natural gas pricing for the first quarter of 2026 from the first quarter of 2025 primarily reflected higher NYMEX benchmark pricing and the ramp-up of LNG Canada, partially offset by increased gas production in the WCSB. The increase in AECO natural gas pricing for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected higher NYMEX benchmark pricing supported by strong export demand from the basin, partially offset by elevated supply conditions in the WCSB associated with increased production and milder-than-normal winter weather.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	603,265	585,497	561,238
North America – Oil Sands Mining and Upgrading ⁽¹⁾	587,946	619,901	595,116
International – Exploration and Production			
North Sea	4,829	7,618	11,507
Offshore Africa	2,039	2,348	5,943
Total International ⁽²⁾	6,868	9,966	17,450
Total Crude oil and NGLs	1,198,079	1,215,364	1,173,804
Natural gas (MMcf/d) ⁽³⁾			
North America	2,668	2,657	2,436
International			
North Sea	2	3	4
Offshore Africa	—	—	11
Total International	2	3	15
Total Natural gas	2,670	2,660	2,451
Total Barrels of oil equivalent (BOE/d)	1,643,160	1,658,681	1,582,348
Product mix			
Light and medium crude oil and NGLs	12%	12%	10%
Pelican Lake heavy crude oil	2%	3%	3%
Primary heavy crude oil	6%	5%	5%
Thermal bitumen	17%	16%	18%
Synthetic crude oil ⁽¹⁾	36%	37%	38%
Natural gas	27%	27%	26%
Percentage of product sales ^{(1) (4) (5)}			
Crude oil and NGLs	92%	92%	94%
Natural gas	8%	8%	6%

(1) SCO production before royalties excludes SCO consumed internally as diesel.

(2) "International" includes North Sea and Offshore Africa Exploration and Production segments in all instances used in this MD&A.

(3) Natural gas production volumes approximate sales volumes.

(4) Net of blending and feedstock costs and excluding risk management activities.

(5) Excluding Midstream and Refining revenue.

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	497,369	499,585	455,307
North America – Oil Sands Mining and Upgrading ⁽¹⁾	490,850	518,709	480,227
International – Exploration and Production			
North Sea	4,825	7,610	11,493
Offshore Africa	2,039	2,240	5,685
Total International	6,864	9,850	17,178
Total Crude oil and NGLs	995,083	1,028,144	952,712
Natural gas (MMcf/d)			
North America	2,544	2,570	2,348
International			
North Sea	2	3	4
Offshore Africa	—	—	11
Total International	2	3	15
Total Natural gas	2,546	2,573	2,363
Total Barrels of oil equivalent (BOE/d)	1,419,481	1,456,944	1,346,536

(1) SCO production net of royalties excludes SCO consumed internally as diesel.

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, thermal bitumen, SCO, and natural gas.

Crude oil and NGLs production before royalties for the first quarter of 2026 averaged 1,198,079 bbl/d, comparable with 1,173,804 bbl/d for the first quarter of 2025 and 1,215,364 bbl/d for the fourth quarter of 2025. Crude oil and NGLs production before royalties primarily reflected the acquisitions completed in the second and third quarters of 2025 and the first quarter of 2026, and thermal pad additions at Pike, offset by the cyclical nature of Primrose, combined with third-party natural gas supply restrictions and unplanned maintenance activities in the Oil Sands Mining and Upgrading segment.

Annual crude oil and NGLs production before royalties for 2026 is targeted to average between 1,188,000 bbl/d and 1,229,000 bbl/d. Production targets constitute forward-looking statements. Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

Natural gas production before royalties for the first quarter of 2026 averaged 2,670 MMcf/d, an increase of 9% from 2,451 MMcf/d for the first quarter of 2025 and comparable with 2,660 MMcf/d for the fourth quarter of 2025. The increase in natural gas production before royalties for the first quarter of 2026 from the first quarter of 2025 primarily reflected the acquisitions completed in the second and third quarters of 2025 and the first quarter of 2026, partially offset by natural field declines.

Annual natural gas production before royalties for 2026 is targeted to average between 2,560 MMcf/d and 2,615 MMcf/d. Production targets constitute forward-looking statements. Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the first quarter of 2026 of 603,265 bbl/d increased 7% from 561,238 bbl/d for the first quarter of 2025 and increased 3% from 585,497 bbl/d for the fourth quarter of 2025. The increase in North America crude oil and NGLs production before royalties for the first quarter of 2026 from the first quarter of 2025 primarily reflected the acquisitions completed in the second and third quarters of 2025 and the first quarter of 2026, combined with thermal pad additions at Pike, and strong drilling results, partially offset by the cyclical nature of Primrose. The increase in North America crude oil and NGLs production before royalties for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected the acquisition completed in the first quarter of 2026, thermal pad additions at Pike, and strong heavy oil drilling results, partially offset by the cyclical nature of Primrose and natural field declines.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 274,674 bbl/d for the first quarter of 2026, a decrease of 4% from 284,706 bbl/d for the first quarter of 2025 and an increase of 3% from 266,308 bbl/d for the fourth quarter of 2025. The decrease in thermal in situ production for the first quarter of 2026 from the first quarter of 2025 primarily reflected the cyclical nature of Primrose and natural field declines, partially offset by thermal pad additions at Pike. The increase in thermal in situ production for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected thermal pad additions at Pike, partially offset by the cyclical nature of Primrose.

Pelican Lake heavy crude oil production before royalties for the first quarter of 2026 averaged 40,548 bbl/d, a decrease of 6% from 43,175 bbl/d for the first quarter of 2025 reflecting Pelican Lake's long life low decline production, and comparable with 41,577 bbl/d for the fourth quarter of 2025.

Natural gas production before royalties averaged 2,668 MMcf/d for the first quarter of 2026, an increase of 10% from 2,436 MMcf/d for the first quarter of 2025 and comparable with 2,657 MMcf/d for the fourth quarter of 2025. The increase in natural gas production before royalties for the first quarter of 2026 from the first quarter of 2025 primarily reflected the acquisitions completed in the second and third quarters of 2025 and the first quarter of 2026, partially offset by natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the first quarter of 2026 averaged 587,946 bbl/d, comparable with 595,116 bbl/d for the first quarter of 2025 and a decrease of 5% from 619,901 bbl/d for the fourth quarter of 2025. The decrease in SCO production before royalties for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected third-party natural gas supply restrictions and unplanned maintenance activities.

International – Exploration and Production

International crude oil and NGLs production before royalties for the first quarter of 2026 averaged 6,868 bbl/d, a decrease of 61% from 17,450 bbl/d for the first quarter of 2025 and a decrease of 31% from 9,966 bbl/d for the fourth quarter of 2025. The decrease in crude oil and NGLs production before royalties for the first quarter of 2026 from the first quarter of 2025 reflected the temporary suspension of production at Baobab in Offshore Africa due to planned maintenance on its FPSO, which is expected to return to service in the second quarter of 2026, planned North Sea abandonments conducted as part of the previously announced decommissioning plans, and maintenance activities. The decrease in crude oil and NGLs production before royalties for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected maintenance activities.

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Crude oil and NGLs (\$/bbl) ⁽¹⁾			
Realized price ⁽²⁾	\$ 76.02	\$ 64.42	\$ 79.85
Transportation ⁽³⁾	7.05	7.14	6.40
Realized price, net of transportation ⁽²⁾	68.97	57.28	73.45
Royalties ⁽⁴⁾	13.41	9.46	14.36
Production expense ⁽⁵⁾	13.54	14.35	15.74
Netback ⁽²⁾	\$ 42.02	\$ 33.47	\$ 43.35
Natural gas (\$/Mcf) ⁽¹⁾			
Realized price ⁽⁶⁾	\$ 3.32	\$ 2.89	\$ 3.13
Transportation ⁽³⁾	0.58	0.56	0.63
Realized price, net of transportation	2.74	2.33	2.50
Royalties ⁽⁴⁾	0.15	0.09	0.11
Production expense ⁽⁵⁾	1.24	1.10	1.20
Netback ⁽⁷⁾	\$ 1.35	\$ 1.14	\$ 1.19
Barrels of oil equivalent (\$/BOE) ⁽¹⁾			
Realized price ⁽²⁾	\$ 52.88	\$ 44.85	\$ 54.95
Transportation ⁽³⁾	5.54	5.56	5.34
Realized price, net of transportation ⁽²⁾	47.34	39.29	49.61
Royalties ⁽⁴⁾	8.23	5.73	8.76
Production expense ⁽⁵⁾	10.96	11.08	12.23
Netback ⁽²⁾	\$ 28.15	\$ 22.48	\$ 28.62

(1) For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

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

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

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

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

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

(7) Natural gas netbacks exclude NGLs netbacks derived from the Company's liquids-rich natural gas plays.

REALIZED PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Crude oil and NGLs (\$/bbl) ⁽¹⁾			
North America ⁽²⁾	\$ 75.91	\$ 63.83	\$ 78.56
International average ⁽³⁾	\$ 91.81	\$ 87.45	\$ 107.04
North Sea ⁽³⁾	\$ 91.81	\$ 89.02	\$ 107.57
Offshore Africa ⁽³⁾	\$ —	\$ 83.53	\$ 106.30
Crude oil and NGLs average ⁽²⁾	\$ 76.02	\$ 64.42	\$ 79.85
Natural gas (\$/Mcf) ^{(1) (3)}			
North America	\$ 3.32	\$ 2.89	\$ 3.06
International average	\$ 11.26	\$ 8.87	\$ 14.46
North Sea	\$ 11.26	\$ 8.87	\$ 16.43
Offshore Africa	\$ —	\$ —	\$ 13.65
Natural gas average	\$ 3.32	\$ 2.89	\$ 3.13
Average (\$/BOE) ^{(1) (2)}	\$ 52.88	\$ 44.85	\$ 54.95

(1) For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

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

(3) Calculated as crude oil and NGLs sales, and natural gas sales divided by respective sales volumes.

North America

North America realized crude oil and NGLs prices averaged \$75.91 per bbl for the first quarter of 2026, a decrease of 3% from \$78.56 per bbl for the first quarter of 2025 and an increase of 19% from \$63.83 per bbl for the fourth quarter of 2025. The decrease in North America realized crude oil and NGLs prices per bbl for the first quarter of 2026 from the first quarter of 2025 primarily reflected the widening of the WCS Heavy Differential. The increase for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected higher WTI benchmark pricing. Realized crude oil and NGLs pricing is also directly impacted by fluctuations in foreign exchange rates as sales prices are primarily denominated with reference to US dollar benchmarks. The Company continues to focus on its crude oil blending and marketing strategy and in the first quarter of 2026 contributed approximately 247,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 8% to average \$3.32 per Mcf for the first quarter of 2026 from \$3.06 per Mcf for the first quarter of 2025 and increased 15% from \$2.89 per Mcf for the fourth quarter of 2025. The increase in North America realized natural gas prices per Mcf for the first quarter of 2026 from the comparable periods primarily reflected higher benchmark pricing.

The prices received in the North America Exploration and Production segment by product type were as follows:

(Quarterly average)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Wellhead Price ⁽¹⁾			
Light and medium crude oil and NGLs (\$/bbl)	\$ 73.85	\$ 58.26	\$ 76.47
Pelican Lake heavy crude oil (\$/bbl)	\$ 78.70	\$ 66.75	\$ 83.57
Primary heavy crude oil (\$/bbl)	\$ 76.54	\$ 65.69	\$ 81.76
Thermal bitumen (\$/bbl)	\$ 76.72	\$ 66.61	\$ 77.96
Natural gas (\$/Mcf)	\$ 3.32	\$ 2.89	\$ 3.06

(1) Amounts expressed on a per unit basis are based on sales volumes of the respective product type.

International

International realized crude oil and NGLs prices decreased 14% to average \$91.81 per bbl for the first quarter of 2026 from \$107.04 per bbl for the first quarter of 2025 and increased 5% from \$87.45 per bbl for the fourth quarter of 2025. Realized crude oil and NGLs prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, prevailing Brent benchmark prices and foreign exchange rates at the time of lifting.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Crude oil and NGLs (\$/bbl) ⁽¹⁾			
North America	\$ 13.51	\$ 9.67	\$ 14.94
International average	\$ 0.08	\$ 1.16	\$ 1.99
North Sea	\$ 0.08	\$ 0.09	\$ 0.14
Offshore Africa	\$ —	\$ 3.84	\$ 4.61
Crude oil and NGLs average	\$ 13.41	\$ 9.46	\$ 14.36
Natural gas (\$/Mcf) ⁽¹⁾			
North America	\$ 0.15	\$ 0.09	\$ 0.11
Offshore Africa	\$ —	\$ —	\$ 0.63
Natural gas average	\$ 0.15	\$ 0.09	\$ 0.11
Average (\$/BOE) ⁽¹⁾	\$ 8.23	\$ 5.73	\$ 8.76

(1) Calculated as royalties divided by respective sales volumes. For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

North America

North America crude oil and NGLs and natural gas royalties for the first quarter of 2026 and the comparable periods reflected movements in benchmark commodity prices, fluctuations in the WCS Heavy Differential and the impact of sliding scale royalty rates.

Crude oil and NGLs royalty rates⁽¹⁾ averaged approximately 18% of product sales for the first quarter of 2026 compared with 19% for the first quarter of 2025 and 15% for the fourth quarter of 2025. The decrease in royalty rates for the first quarter of 2026 from the first quarter of 2025 primarily reflected the widening of the WCS Heavy Differential. The increase in royalty rates for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected higher WTI benchmark pricing.

Natural gas royalty rates averaged approximately 5% of product sales for the first quarter of 2026 compared with 4% for the first quarter of 2025 and 3% for the fourth quarter of 2025. The increase in royalty rates for the first quarter of 2026 from the comparable periods primarily reflected higher benchmark pricing.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital expenditures and production expenses, the status of payouts, and the timing of liftings from each field.

No royalty expense was recognized in the first quarter of 2026 due to the absence of product sales. By comparison, royalty rates were 4% of product sales for the first quarter of 2025 and 5% for the fourth quarter of 2025. Royalty rates as a percentage of product sales reflected the timing of liftings, and the status of payout in the various fields.

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

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Crude oil and NGLs (\$/bbl) ⁽¹⁾			
North America	\$ 13.03	\$ 12.24	\$ 12.65
International average	\$ 85.18	\$ 96.90	\$ 80.63
North Sea	\$ 85.18	\$ 115.45	\$ 117.56
Offshore Africa	\$ —	\$ 50.50	\$ 28.26
Crude oil and NGLs average	\$ 13.54	\$ 14.35	\$ 15.74
Natural gas (\$/Mcf) ⁽¹⁾			
North America	\$ 1.23	\$ 1.09	\$ 1.16
International average	\$ 7.60	\$ 11.69	\$ 7.60
North Sea	\$ 7.60	\$ 11.69	\$ 10.52
Offshore Africa	\$ —	\$ —	\$ 6.42
Natural gas average	\$ 1.24	\$ 1.10	\$ 1.20
Average (\$/BOE) ⁽¹⁾	\$ 10.96	\$ 11.08	\$ 12.23

(1) Calculated as production expense divided by respective sales volumes. For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

North America

North America crude oil and NGLs production expense for the first quarter of 2026 averaged \$13.03 per bbl, comparable with \$12.65 per bbl for the first quarter of 2025 and an increase of 6% from \$12.24 per bbl for the fourth quarter of 2025. The increase in crude oil and NGLs production expense per bbl for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected seasonal service costs.

North America natural gas production expense for the first quarter of 2026 of \$1.23 per Mcf increased 6% from \$1.16 per Mcf for the first quarter of 2025 and increased 13% from \$1.09 per Mcf for the fourth quarter of 2025. The increase in natural gas production expense per Mcf for the first quarter of 2026 from the first quarter of 2025 primarily reflected higher energy and service costs. The increase in natural gas production expense per Mcf for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected seasonal service costs.

International

International crude oil and NGLs production expense for the first quarter of 2026 of \$85.18 per bbl increased 6% from \$80.63 per bbl for the first quarter of 2025 and decreased 12% from \$96.90 per bbl for the fourth quarter of 2025. The increase in crude oil and NGLs production expense per bbl for the first quarter of 2026 from the first quarter of 2025 primarily reflected activities at Ninian in the pre-cessation period, the timing of liftings from various fields that have different cost structures, and the impact of foreign exchange. The decrease in crude oil and NGLs production expense per bbl for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected the timing of liftings from various fields that have different cost structures.

ADJUSTED DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
North America	\$ 1,131	\$ 1,217	\$ 1,092
North Sea	6	215	40
Offshore Africa	14	340	59
Depletion, depreciation and amortization	\$ 1,151	\$ 1,772	\$ 1,191
Less: Recoverability charges ⁽¹⁾	—	519	—
Adjusted depletion, depreciation and amortization ⁽²⁾	\$ 1,151	\$ 1,253	\$ 1,191
\$/BOE ⁽³⁾	\$ 12.12	\$ 12.98	\$ 13.27

(1) In the fourth quarter of 2025, the Company recognized recoverability charges of \$519 million in depletion, depreciation and amortization expense, including \$204 million related to North Sea abandonment and decommissioning activities, \$269 million related to the decision not to pursue an extension of its Production Sharing Contract for the Espoir field in Offshore Africa, and \$46 million related to the decision not to pursue development of Kossipo in Offshore Africa.

(2) This is a non-GAAP financial measure used to calculate depletion, depreciation and amortization, less the impact of charges that are not related to current production or current period normal course depletion, depreciation and amortization expense such as asset recoverability charges. It may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements (depletion, depreciation and amortization expense), as an indication of the Company's performance.

(3) This is a non-GAAP ratio calculated as adjusted depletion, depreciation and amortization expense divided by sales volumes. For sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Adjusted depletion, depreciation and amortization expense for the first quarter of 2026 averaged \$12.12 per BOE, a decrease of 9% from \$13.27 per BOE for the first quarter of 2025 and a decrease of 7% from \$12.98 per BOE for the fourth quarter of 2025. The decrease in adjusted depletion, depreciation and amortization expense per BOE for the first quarter of 2026 from the first quarter of 2025 primarily reflected changes in North America depletion rates due to changes in reserve estimates at December 31, 2025 combined with the impact of higher sales volumes in the first quarter of 2026, partially offset by a higher depletable base following acquisitions completed in 2025. The decrease for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected changes in North America depletion rates due to changes in reserve estimates at December 31, 2025.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
North America	\$ 55	\$ 58	\$ 53
North Sea	20	23	14
Offshore Africa	2	2	2
Asset retirement obligation accretion	\$ 77	\$ 83	\$ 69
\$/BOE ⁽¹⁾	\$ 0.80	\$ 0.85	\$ 0.77

(1) Calculated as asset retirement obligation accretion divided by sales volumes. For sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Asset retirement obligation accretion expense for the first quarter of 2026 averaged \$0.80 per BOE, an increase of 4% from \$0.77 per BOE for the first quarter of 2025 and a decrease of 6% from \$0.85 per BOE for the fourth quarter of 2025. The increase in asset retirement obligation accretion expense per BOE for the first quarter of 2026 from the first quarter of 2025 reflected the impact of revisions in cost and timing estimates in the North Sea in the second half of 2025, partially offset by higher sales volumes in the first quarter of 2026. The decrease for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected the impact of revisions to cost and timing estimates and changes in discount rates at December 31, 2025.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable, and efficient operations, leveraging its technical expertise across the Horizon and AOSP sites, with SCO production averaging 587,946 bbl/d in the first quarter of 2026.

REALIZED PRODUCT PRICES, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

(\$/bbl)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Realized SCO sales price ⁽¹⁾	\$ 89.68	\$ 75.90	\$ 95.52
Bitumen value for royalty purposes ⁽²⁾	\$ 66.45	\$ 58.68	\$ 73.72
Bitumen royalties ⁽³⁾	\$ 15.20	\$ 9.54	\$ 18.22
Transportation ⁽⁴⁾	\$ 2.60	\$ 2.56	\$ 3.21

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

(2) Calculated as the quarterly average of the bitumen methodology price.

(3) Calculated as royalties divided by sales volumes.

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

The realized SCO sales price averaged \$89.68 per bbl for the first quarter of 2026, a decrease of 6% from \$95.52 per bbl for the first quarter of 2025 and an increase of 18% from \$75.90 per bbl for the fourth quarter of 2025. The decrease in realized SCO sales price per bbl for the first quarter of 2026 from the first quarter of 2025 primarily reflected prevailing benchmark pricing and changes in the product sales mix between periods. The increase in realized SCO sales price per bbl for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected higher WTI benchmark pricing.

The fluctuations in bitumen royalties per bbl in any particular period reflect prevailing bitumen value for royalty purposes, and the impact of sliding scale royalty rates. The decrease in bitumen royalties per bbl for the first quarter of 2026 from the first quarter of 2025 primarily reflected the decrease in average bitumen value for royalty purposes. The increase for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected the increase in average bitumen value for royalty purposes and the impact of sliding scale royalty rates.

Transportation expense averaged \$2.60 per bbl for the first quarter of 2026, a decrease of 19% from \$3.21 per bbl for the first quarter of 2025 and comparable with \$2.56 per bbl for the fourth quarter of 2025. The decrease in transportation expense per bbl for the first quarter of 2026 from the first quarter of 2025 primarily reflected lower transportation expense following the recognition of the Corridor pipeline as a lease asset following the AOSP asset swap in the fourth quarter of 2025.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

(\$ millions)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Production expense, excluding natural gas costs	\$ 1,214	\$ 1,207	\$ 1,135
Natural gas costs	55	46	50
Production expense	\$ 1,269	\$ 1,253	\$ 1,185

(\$/bbl)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Production expense, excluding natural gas costs ⁽¹⁾	\$ 22.70	\$ 21.03	\$ 20.95
Natural gas costs ⁽²⁾	1.03	0.81	0.93
Production expense ⁽³⁾	\$ 23.73	\$ 21.84	\$ 21.88
Sales volumes (bbl/d)	594,042	624,125	602,048

(1) Calculated as production expense, excluding natural gas costs, divided by sales volumes.

(2) Calculated as natural gas costs divided by sales volumes.

(3) Calculated as production expense divided by sales volumes.

Production expense for the first quarter of 2026 averaged \$23.73 per bbl, an increase of 8% from \$21.88 per bbl for the first quarter of 2025 and an increase of 9% from \$21.84 per bbl for the fourth quarter of 2025. The increase in production expense per bbl for the first quarter of 2026 from the comparable periods primarily reflected unplanned maintenance activities and lower sales volumes.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Depletion, depreciation and amortization	\$ 722	\$ 762	\$ 675
\$/bbl ⁽¹⁾	\$ 13.50	\$ 13.26	\$ 12.45

(1) Calculated as depletion, depreciation and amortization expense divided by sales volumes.

Depletion, depreciation and amortization expense for the first quarter of 2026 of \$13.50 per bbl increased 8% from \$12.45 per bbl for the first quarter of 2025 and was comparable with \$13.26 per bbl for the fourth quarter of 2025. The increase in depletion, depreciation and amortization expense per bbl for the first quarter of 2026 from the first quarter of 2025 primarily reflected a higher depletable base due to the gain recognized on the AOSP mine assets, combined with the recognition of the Corridor pipeline as a lease asset, both arising from the AOSP asset swap in the fourth quarter of 2025.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Asset retirement obligation accretion	\$ 21	\$ 21	\$ 22
\$/bbl ⁽¹⁾	\$ 0.40	\$ 0.37	\$ 0.40

(1) Calculated as asset retirement obligation accretion divided by sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Asset retirement obligation accretion expense for the first quarter of 2026 of \$0.40 per bbl was comparable with \$0.40 per bbl for the first quarter of 2025 and increased 8% from \$0.37 per bbl for the fourth quarter of 2025. The increase in asset retirement obligation accretion expense per bbl for the first quarter of 2026 from the fourth quarter of 2025 primarily reflected the impact of lower sales volumes in the first quarter of 2026.

MIDSTREAM AND REFINING

(\$ millions)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Product sales			
Midstream activities	\$ 23	\$ 23	\$ 22
NWRP, refined product sales and other	277	206	221
Segmented revenue	300	229	243
Less:			
NWRP, refining toll	57	63	68
Midstream activities	6	5	5
Production expense	63	68	73
NWRP, feedstock costs	170	144	172
Transportation expense	4	4	4
Depreciation	4	4	4
Segmented earnings (loss)	\$ 59	\$ 9	\$ (10)

The Company's Midstream and Refining assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose, and the Company's 50% equity investment in North West Redwater Partnership ("NWRP").

NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 bbl/d. The refinery processes approximately 50,000 bbl/d of bitumen feedstock, including 12,500 bbl/d of bitumen feedstock for the Company (25% toll payer) and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058. Sales of diesel and other refined products and associated refining tolls are recognized in the Midstream and Refining segment. For the first quarter of 2026, production of ultra-low sulphur diesel and other refined products averaged 94,351 BOE/d (23,588 BOE/d to the Company) (three months ended December 31, 2025 – 89,969 BOE/d; 22,492 BOE/d to the Company; three months ended March 31, 2025 – 83,863 BOE/d; 20,966 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at March 31, 2026, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$471 million (December 31, 2025 – \$496 million). For the three months ended March 31, 2026, the Company's recovery of its share of unrecognized equity losses was \$25 million (three months ended December 31, 2025 – unrecognized equity loss of \$13 million; three months ended March 31, 2025 – unrecognized equity loss of \$19 million).

ADMINISTRATION EXPENSE

(\$ millions, except per BOE amounts)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Administration expense	\$ 154	\$ 160	\$ 152
\$/BOE ⁽¹⁾	\$ 1.04	\$ 1.04	\$ 1.06
Sales volumes (BOE/d) ⁽²⁾	1,649,558	1,672,708	1,599,487

(1) Calculated as administration expense divided by sales volumes.

(2) Total Company sales volumes.

Administration expense for the first quarter of 2026 of \$1.04 per BOE was comparable with the first quarter of 2025 and the fourth quarter of 2025.

SHARE-BASED COMPENSATION

(\$ millions)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Share-based compensation expense	\$ 644	\$ 83	\$ 26

The Company's Stock Option Plan provides employees with the right to receive common shares or a cash payment in exchange for stock options surrendered. The Performance Share Unit ("PSU") Plan provides certain executive employees of the Company with the right to receive a cash payment; the amount of which is determined with reference to the value of the Company's shares, by individual employee performance, and the extent to which certain other performance measures are met.

The Company recognized \$644 million of share-based compensation expense for the three months ended March 31, 2026 primarily as a result of changes in the Company's share price, the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, and the impact of vested stock options exercised or surrendered during the period.

INTEREST AND OTHER FINANCING EXPENSE

(\$ millions, except effective interest rate)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Interest and other financing expense	\$ 318	\$ 245	\$ 258
Less: Interest (income) and other expense ⁽¹⁾	64	(18)	(6)
Interest expense on long-term debt and lease liabilities ⁽¹⁾	\$ 254	\$ 263	\$ 264
Average current and long-term debt ⁽²⁾	\$ 17,445	\$ 18,103	\$ 19,147
Average lease liabilities ⁽²⁾	3,077	2,008	1,422
Average long-term debt and lease liabilities ⁽²⁾	\$ 20,522	\$ 20,111	\$ 20,569
Average effective interest rate ^{(3) (4)}	4.9%	5.1%	5.0%
Interest and other financing expense (\$/BOE) ⁽⁵⁾	\$ 2.14	\$ 1.60	\$ 1.79
Sales volumes (BOE/d) ⁽⁶⁾	1,649,558	1,672,708	1,599,487

(1) Item is a component of interest and other financing expense.

(2) The average of current and long-term debt and lease liabilities outstanding during the respective period.

(3) This is a non-GAAP ratio and may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance.

(4) Calculated as the average interest expense on long-term debt and lease liabilities divided by the average long-term debt and lease liabilities balance. The Company presents its average effective interest rate for financial statement users to evaluate the Company's average cost of debt borrowings.

(5) Calculated as interest and other financing expense divided by sales volumes.

(6) Total Company sales volumes.

Interest and other financing expense for the first quarter of 2026 increased 20% to \$2.14 per BOE from \$1.79 per BOE for the first quarter of 2025 and increased 34% from \$1.60 per BOE for the fourth quarter of 2025. The increase in interest and other financing expense per BOE for the first quarter of 2026 from the comparable periods primarily reflected accrued interest in the North Sea, combined with higher average lease liabilities following the recognition of the Corridor pipeline in the fourth quarter of 2025.

The Company's average effective interest rate for the first quarter of 2026 was 4.9%, a decrease from 5.0% for the first quarter of 2025 and a decrease from 5.1% for the fourth quarter of 2025, reflecting interest rates on the medium-term note issuances in December 2025, combined with a lower effective interest rate on higher average lease liabilities.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, interest rate, and foreign currency exposures. These derivative financial instruments are not intended for trading or speculative purposes.

(\$ millions)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Foreign currency forward contracts	\$ 43	\$ (24)	\$ (20)
Foreign currency put options	—	—	(4)
Natural gas financial contracts ^{(1) (2)}	2	(3)	(3)
Net realized loss (gain)	45	(27)	(27)
Foreign currency forward contracts	1	5	14
Foreign currency put options	—	—	(2)
Natural gas financial contracts ^{(1) (2)}	3	6	(9)
Natural gas embedded derivative ⁽³⁾	312	(88)	—
Net unrealized loss (gain)	316	(77)	3
Net loss (gain)	\$ 361	\$ (104)	\$ (24)

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

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

(3) In the second quarter of 2025, the Company entered into a long-term natural gas supply agreement containing an embedded derivative. Further details are disclosed in note 14 to the financial statements.

The Company recorded a net realized risk management loss of \$45 million for the three months ended March 31, 2026.

The Company recorded a net unrealized loss of \$316 million (\$243 million after tax of \$73 million) on its risk management activities for the three months ended March 31, 2026 (three months ended December 31, 2025 – unrealized gain of \$77 million (\$59 million after tax of \$18 million); three months ended March 31, 2025 – unrealized loss of \$3 million (\$2 million after tax of \$1 million)).

Further details related to outstanding derivative financial instruments as at March 31, 2026 are disclosed in note 14 to the financial statements.

FOREIGN EXCHANGE

(\$ millions)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Net realized (gain) loss	\$ (23)	\$ (13)	\$ 242
Net unrealized loss (gain)	285	(193)	(285)
Net loss (gain) ⁽¹⁾	\$ 262	\$ (206)	\$ (43)

(1) Amounts are reported net of derivative financial instruments designated as cash flow hedges.

The net realized foreign exchange gain for the first quarter of 2026 was primarily related to exchange rate fluctuations on the settlement of US dollar debt and working capital items denominated in US dollars.

The net unrealized foreign exchange loss for the first quarter of 2026 was primarily related to the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at March 31, 2026 was US\$0.7166 (December 31, 2025 – US\$0.7292; March 31, 2025 – US\$0.6955).

INCOME TAXES

(\$ millions, except effective tax rates)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
North America ⁽¹⁾	\$ 671	\$ 596	\$ 569
North Sea	(53)	(16)	(26)
Offshore Africa	—	11	5
Current PRT – North Sea	(65)	(51)	(39)
Other taxes	2	3	2
Current income tax	555	543	511
Deferred corporate income tax	(59)	1,017	119
Deferred PRT – North Sea	(114)	(15)	9
Deferred income tax	(173)	1,002	128
Income tax	\$ 382	\$ 1,545	\$ 639
Earnings before taxes	\$ 1,730	\$ 6,848	\$ 3,097
Effective tax rate on net earnings ⁽²⁾	22%	23%	21%

(\$ millions, except effective tax rates)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Income tax	\$ 382	\$ 1,545	\$ 639
Tax effect on non-operating items ⁽³⁾	126	(1,088)	5
Current PRT – North Sea	65	51	39
Deferred PRT – North Sea	114	(26)	(9)
Other taxes	(2)	(3)	(2)
Effective tax on adjusted net earnings	\$ 685	\$ 479	\$ 672
Adjusted net earnings from operations ⁽⁴⁾	\$ 2,446	\$ 1,711	\$ 2,436
Adjusted net earnings from operations, before taxes	\$ 3,131	\$ 2,190	\$ 3,108
Effective tax rate on adjusted net earnings from operations ^{(5) (6)}	22%	22%	22%

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

(2) Calculated as total of current and deferred income tax divided by earnings before taxes.

(3) Includes the net income tax effect on PSUs, certain stock options, unrealized risk management, and a gain on disposition and remeasurement, and recoverability charges related to the North Sea and Offshore Africa recorded in the fourth quarter of 2025.

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

(5) This is a non-GAAP ratio and may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance.

(6) Calculated as effective tax on adjusted net earnings divided by adjusted net earnings from operations, before taxes. The Company presents its effective tax rate on adjusted net earnings from operations for financial statement users to evaluate the Company's effective tax rate on its core business activities.

The effective tax rate on net earnings and adjusted net earnings from operations for the first quarter of 2026 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings.

Deferred corporate income tax in North America for the fourth quarter of 2025 included the deferred tax impacts of the gain on disposition and remeasurement associated with the AOSP asset swap.

The current and deferred corporate income tax and the current and deferred PRT in the North Sea for the first quarter of 2026 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the decommissioning activities in the North Sea. Deferred PRT and income taxes for the fourth quarter of 2025 also reflected the impact of the recoverability charges recognized in depletion, depreciation and amortization expense.

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

NET CAPITAL EXPENDITURES ^{(1) (2)}

(\$ millions)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Exploration and Production			
Exploration and Evaluation Assets			
Net expenditures	\$ 23	\$ 4	\$ 19
Net property acquisitions (dispositions)	63	(9)	(13)
Total Exploration and Evaluation Assets	86	(5)	6
Property, Plant and Equipment			
Net property acquisitions	710	45	31
Well drilling, completion and equipping	634	514	536
Production and related facilities	379	398	390
Other	(135)	18	3
Total Property, Plant and Equipment	1,588	975	960
Total Exploration and Production	1,674	970	966
Oil Sands Mining and Upgrading			
Project costs	44	92	55
Sustaining capital	285	340	216
Turnaround costs	11	8	46
Net property acquisitions ⁽³⁾	—	(212)	—
Other	2	4	2
Total Oil Sands Mining and Upgrading	342	232	319
Midstream and Refining	1	2	2
Head Office	11	33	16
Net capital expenditures	\$ 2,028	\$ 1,237	\$ 1,303
Abandonment expenditures	\$ 247	\$ 201	\$ 188
By Segment			
North America	\$ 1,529	\$ 812	\$ 836
North Sea	2	—	3
Offshore Africa	143	158	127
Oil Sands Mining and Upgrading	342	232	319
Midstream and Refining	1	2	2
Head Office	11	33	16
Net capital expenditures	\$ 2,028	\$ 1,237	\$ 1,303

(1) Net capital expenditures exclude the impact of lease assets and fair value adjustments.

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

(3) Includes cash acquired and received as net consideration of \$212 million related to the AOSP asset swap within the Oil Sands Mining and Upgrading segment in the fourth quarter of 2025.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production expenses.

Net capital expenditures were \$2,028 million for the first quarter of 2026 compared with \$1,303 million for the first quarter of 2025 and \$1,237 million for the fourth quarter of 2025. In addition, the Company reported abandonment expenditures of \$247 million for the first quarter of 2026 compared with \$188 million for the first quarter of 2025 and \$201 million for the fourth quarter of 2025.

2026 Capital Budget

On December 16, 2025, the Company announced its 2026 operating capital budget⁽¹⁾ targeted at approximately \$6,300 million. With this capital, the Company is targeting production growth in 2026 of approximately 3% from 2025, as it invests in short and medium-term production, while commencing front-end engineering and design on potential additional medium and long-term value creation opportunities. In addition, the Company targets approximately \$125 million of capital related to carbon capture projects. The Company targets \$993 million in abandonment expenditures for 2026, before recoveries, related to its abandonment and reclamation programs in North America and the North Sea. On March 5, 2026, the Company revised its operating capital forecast to \$5,990 million, included net acquisition capital of \$765 million and increased its production guidance to between 1,615,000 BOE/d and 1,665,000 BOE/d.

Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns, and the balancing of project risks and time horizons. The 2026 capital budget constitutes forward-looking statements and is based on net capital expenditures (Non-GAAP Financial Measure). Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

Drilling Activity^{(1) (2)}

	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
(number of net wells)			
Net successful crude oil wells ⁽³⁾	113	114	74
Net successful natural gas wells	24	20	19
Dry wells	1	1	1
Total	138	135	94
Success rate	99%	99%	99%

(1) Includes drilling activity for North America and International segments.

(2) Excludes stratigraphic and service wells.

(3) Includes bitumen wells.

North America

During the first quarter of 2026, the Company drilled 24 net natural gas wells, 49 net primary heavy crude oil wells, 6 net Pelican Lake heavy crude oil wells, 31 net thermal bitumen wells, and 28 net light crude oil wells.

(1) Forward-looking non-GAAP Financial Measure. The operating capital budget is based on net capital expenditures (Non-GAAP Financial Measure). Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A for more details on net capital expenditures.

LIQUIDITY AND CAPITAL RESOURCES

(\$ millions, except ratios)	Mar 31 2026	Dec 31 2025	Mar 31 2025
Adjusted working capital ⁽¹⁾	\$ 289	\$ 42	\$ 20
Long-term debt, net ⁽²⁾	\$ 16,153	\$ 15,944	\$ 17,335
Shareholders' equity	\$ 44,638	\$ 44,366	\$ 40,445
Debt to book capitalization ⁽²⁾	26.6%	26.4%	30.0%
After-tax return on average capital employed ⁽³⁾	17.5%	19.5%	15.3%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

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

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

As at March 31, 2026, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities, and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt are dependent on factors discussed in the 'Business Environment' section of this MD&A and in the 'Risks and Uncertainties' section of the Company's annual MD&A for the year ended December 31, 2025. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings, as determined by independent rating agencies and market conditions.

The Company continues to believe its internally generated cash flows from operating activities, supported by its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short-, medium-, and long-term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers, and joint venture partners on a regular basis and, where appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;
- Actively managing the allocation of capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments, and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
 - During the first quarter of 2026, the Company cancelled the \$140 million portion of its \$2,565 million revolving syndicated credit facility, maturing June 2027, reducing the capacity to \$2,425 million, with a maturity of June 2029.
 - Borrowings under the Company's credit facilities may be made by way of pricing referenced to CORRA, SOFR, US base rate or Canadian prime rate.
 - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US\$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
 - In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to \$3,000 million of medium-term notes in Canada, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at March 31, 2026, the Company had \$1,350 million remaining on its base shelf prospectus.
 - In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US\$4,500 million of debt securities in the United States, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at March 31, 2026, the Company had US\$3,003 million remaining on its base shelf prospectus.

As at March 31, 2026, the Company had undrawn bank credit facilities of \$5,358 million, and a fully drawn non-revolving term credit facility of \$4,000 million. Including cash and cash equivalents, the Company had approximately \$6,166 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit.

Long-term debt, net was \$16,153 million as at March 31, 2026 (December 31, 2025 – \$15,944 million), resulting in a debt to book capitalization ratio of 26.6% (December 31, 2025 – 26.4%); this ratio was within the 25% to 45% internal range utilized by management. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at March 31, 2026, the Company was in compliance with this covenant.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt as at March 31, 2026 are discussed in note 7 to the financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of commodity put options is in addition to the above parameters.

As at March 31, 2026, the maturity dates of certain financial liabilities, including long-term debt and other long-term liabilities and related interest payments, were as follows:

		Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt ⁽¹⁾	\$	441	\$ 6,061	\$ 2,844	\$ 7,700
Other long-term liabilities ^{(2) (3)}	\$	377	\$ 278	\$ 639	\$ 2,248
Interest and other financing expense ⁽⁴⁾	\$	981	\$ 863	\$ 1,861	\$ 3,562

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

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, \$365 million; one to less than two years, \$278 million; two to less than five years, \$639 million; and thereafter, \$1,777 million.

(3) Includes a gross derivative liability of \$471 million associated with the Company's natural gas embedded derivative. The gross liability is offset by a gross derivative asset of \$102 million, resulting in a net liability of \$369 million.

(4) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at March 31, 2026.

Share Capital

As at March 31, 2026, there were 2,085,710,000 common shares outstanding (December 31, 2025 – 2,081,578,000 common shares) and 59,291,000 stock options outstanding (December 31, 2025 – 54,734,000 stock options). As at May 5, 2026, the Company had 2,080,387,000 common shares outstanding and 57,401,000 stock options outstanding.

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

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

The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 10, 2026, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 182,396,564 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2026 and ending March 12, 2027, subject to applicable securities laws.

For the three months ended March 31, 2026, the Company purchased 5,425,000 common shares at a weighted average price of \$57.26 per common share for a total cost, including tax, of \$311 million. Retained earnings were reduced by \$281 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2026, up to and including May 5, 2026, the Company purchased 5,650,000 common shares at a weighted average price of \$63.19 per common share for a total cost, including tax, of \$360 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at March 31, 2026:

(\$ millions)	Remaining 2026		2027	2028	2029	2030	Thereafter
Product transportation, purchases, and processing ⁽¹⁾	\$	1,729	\$ 2,279	\$ 2,135	\$ 1,977	\$ 1,816	\$ 18,169
North West Redwater Partnership service toll ⁽²⁾	\$	81	\$ 95	\$ 96	\$ 95	\$ 95	\$ 3,865
Offshore vessels and decommissioning equipment	\$	179	\$ —	\$ —	\$ —	\$ —	\$ —
Field equipment and supplies	\$	123	\$ 122	\$ 121	\$ 24	\$ 24	\$ 170
Office leases and other	\$	219	\$ 66	\$ 19	\$ 18	\$ 18	\$ 176

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

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is \$1,764 million of interest payable over the 40-year tolling period, ending in 2058.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions, and judgements in the application of IFRS Accounting Standards that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the Company's annual MD&A and audited consolidated financial statements for the year ended December 31, 2025.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended March 31, 2026 that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting. Due to inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A includes references to non-GAAP and other financial measures as defined in NI 52-112. These financial measures are used by the Company to evaluate its financial performance, financial position, and cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS Accounting Standards and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below.

Adjusted Net Earnings from Operations

Adjusted net earnings from operations is a non-GAAP financial measure that adjusts net earnings as presented in the Company's consolidated statements of earnings, for non-operating items, net of tax impacts. The Company considers adjusted net earnings from operations a key measure in evaluating its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. A reconciliation for adjusted net earnings from operations is presented below.

(\$ millions)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Net earnings	\$ 1,348	\$ 5,303	\$ 2,458
Share-based compensation, net of tax ⁽¹⁾	591	79	22
Unrealized risk management loss (gain), net of tax ⁽²⁾	243	(59)	2
Unrealized foreign exchange loss (gain), net of tax ⁽³⁾	285	(193)	(285)
Realized foreign exchange (gain) loss on financing activities, net of tax ⁽⁴⁾	(21)	(23)	239
Gain on acquisition, disposition, and remeasurement, net of tax ⁽⁵⁾	—	(3,845)	—
Recoverability charges, net of tax ^{(6) (7)}	—	449	—
Non-operating items, net of tax	1,098	(3,592)	(22)
Adjusted net earnings from operations	\$ 2,446	\$ 1,711	\$ 2,436

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU Plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets, and periodic changes in the fair value are recognized in net earnings. Pre-tax share-based compensation for the three months ended March 31, 2026 was an expense of \$644 million (three months ended December 31, 2025 – \$83 million expense; three months ended March 31, 2025 – \$26 million expense).

(2) Derivative financial instruments are recognized at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than those amounts reflected in the financial statements due to changes in prices of the underlying items hedged, primarily natural gas and foreign exchange. The pre-tax unrealized risk management loss for the three months ended March 31, 2026 was \$316 million (three months ended December 31, 2025 – \$77 million gain; three months ended March 31, 2025 – \$3 million loss).

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates and are recognized in net earnings. Pre- and after-tax amounts for these unrealized foreign exchange gains and losses are the same.

(4) Realized foreign exchange gains and losses associated with financing activities primarily result from the repayment of US dollar denominated debt and are recognized in net earnings. Pre- and after-tax amounts for these realized foreign exchange gains and losses are the same.

(5) During the fourth quarter of 2025, the Company completed the AOSP asset swap. As a result, the Company recognized a gain on acquisition, disposition, and remeasurement of \$4,989 million (\$3,845 after-tax) in net earnings.

(6) During the fourth quarter of 2025, the Company recognized a pre-tax non-cash recoverability charge of \$204 million (\$141 million after-tax) in depletion, depreciation and amortization expense relating to the North Sea abandonment and decommissioning activities. The costs are included in capital and abandonment expenditures, consistent with the treatment of all abandonment related expenditures for the purpose of the Company's non-GAAP measures.

(7) During the fourth quarter of 2025, the Company recognized pre-tax non-cash recoverability charges of \$315 million (\$308 million after-tax) in depletion, depreciation and amortization expense relating to Offshore Africa.

Adjusted Funds Flow

Adjusted funds flow is a non-GAAP financial measure that represents cash flows from operating activities as presented in the Company's consolidated statements of cash flows adjusted for the net change in non-cash working capital, abandonment expenditures, and movements in other long-term assets. The Company considers adjusted funds flow a key measure in evaluating its performance, as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment, repay debt, and provide returns to shareholders through dividends and share buybacks. A reconciliation for adjusted funds flow from cash flows from operating activities is presented below.

(\$ millions)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Cash flows from operating activities	\$ 3,282	\$ 3,768	\$ 4,284
Net change in non-cash working capital	818	(134)	(82)
Abandonment expenditures	247	201	188
Movements in other long-term assets ⁽¹⁾	27	(87)	140
Adjusted funds flow	\$ 4,374	\$ 3,748	\$ 4,530

(1) Includes the unamortized cost of contributions to the Company's employee bonus program, interest on PRT recoveries in the North Sea, and prepaid cost of service tolls.

Adjusted Net Earnings from Operations and Adjusted Funds Flow, Per Common Share (Basic and Diluted)

Adjusted net earnings from operations and adjusted funds flow, per common share (basic and diluted) are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 13 to the financial statements. These non-GAAP measures, disclosed on a per share basis, enable a comparison to the per share amounts disclosed in the Company's financial statements prepared in accordance with IFRS Accounting Standards.

Netback

Netback is a non-GAAP ratio that represents net cash flows provided from core activities after the impact of all costs associated with bringing a product to market, on a per unit basis. The Company considers netback a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. Refer to the 'Operating Highlights – Exploration and Production' section of this MD&A for the netback calculations on a per unit basis for crude oil and NGLs and on a total barrels of oil equivalent basis.

The netback calculations include the realized price non-GAAP financial measure which is reconciled below to its respective line item in note 16 to the financial statements.

Realized Price (\$/bbl and \$/BOE) – Exploration and Production

Realized price (\$/bbl and \$/BOE) is a non-GAAP ratio calculated as realized crude oil and NGLs sales and total realized BOE sales (non-GAAP financial measures) divided by respective sales volumes. Realized crude oil and NGLs sales and total realized BOE sales is comprised of crude oil and NGLs sales and natural gas sales less blending and feedstock costs and other by-product sales, as disclosed in note 16 to the financial statements. The Company considers realized price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit the Company obtained on the market for its crude oil and NGLs sales volumes and BOE sales volumes.

Reconciliations for Exploration and Production realized crude oil and NGLs sales and BOE sales and the calculations for realized price are presented below.

(\$ millions, except bbl/d and \$/bbl)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Crude oil and NGLs (bbl/d)			
North America	606,104	590,144	562,183
International			
North Sea	4,332	10,804	15,665
Offshore Africa	—	4,318	11,048
Total International	4,332	15,122	26,713
Total sales volumes	610,436	605,266	588,896
Crude oil and NGLs sales ⁽¹⁾	\$ 5,425	\$ 4,539	\$ 5,624
Less: Blending and feedstock costs ⁽²⁾	1,248	951	1,391
Realized crude oil and NGLs sales	\$ 4,177	\$ 3,588	\$ 4,233
Realized price (\$/bbl)	\$ 76.02	\$ 64.42	\$ 79.85

(1) Crude oil and NGLs sales in note 16 to the financial statements.

(2) Blending and feedstock costs in note 16 to the financial statements.

(\$ millions, except BOE/d and \$/BOE)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Barrels of oil equivalent (BOE/d)			
North America	1,050,813	1,032,973	968,189
International			
North Sea	4,703	11,292	16,399
Offshore Africa	—	4,318	12,851
Total International	4,703	15,610	29,250
Total sales volumes	1,055,516	1,048,583	997,439
Barrels of oil equivalent sales ⁽¹⁾	\$ 6,223	\$ 5,247	\$ 6,314
Less: Blending and feedstock costs ⁽²⁾	1,248	951	1,391
Less: Sulphur income	(48)	(30)	(9)
Realized barrels of oil equivalent sales	\$ 5,023	\$ 4,326	\$ 4,932
Realized price (\$/BOE)	\$ 52.88	\$ 44.85	\$ 54.95

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 16 to the financial statements.

(2) Blending and feedstock costs in note 16 to the financial statements.

North America – Realized Product Prices and Royalties

Realized crude oil and NGLs price (\$/bbl) is a non-GAAP ratio calculated as realized crude oil and NGLs sales (non-GAAP financial measure) divided by sales volumes. Realized crude oil and NGLs sales is comprised of crude oil and NGLs sales less blending and feedstock costs, as disclosed in note 16 to the financial statements. The Company considers the realized crude oil and NGLs price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its crude oil and NGLs sales volumes.

Crude oil and NGLs royalty rate is a non-GAAP ratio that is calculated as crude oil and NGLs royalties divided by realized crude oil and NGLs sales. The Company considers crude oil and NGLs royalty rate a key measure in evaluating its performance, as it describes the Company's royalties for crude oil and NGLs sales volumes on a per unit basis.

A reconciliation for North America realized crude oil and NGLs sales and the calculations for realized crude oil and NGLs prices and the royalty rates are presented below.

(\$ millions, except \$/bbl and royalty rates)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Crude oil and NGLs sales ⁽¹⁾	\$ 5,389	\$ 4,417	\$ 5,366
Less: Blending and feedstock costs ⁽²⁾	1,248	951	1,391
Realized crude oil and NGLs sales	\$ 4,141	\$ 3,466	\$ 3,975
Realized crude oil and NGLs prices (\$/bbl)	\$ 75.91	\$ 63.83	\$ 78.56
Crude oil and NGLs royalties ⁽³⁾	\$ 737	\$ 525	\$ 756
Crude oil and NGLs royalty rates	18%	15%	19%

(1) Crude oil and NGLs sales in note 16 to the financial statements.

(2) Blending and feedstock costs in note 16 to the financial statements.

(3) Item is a component of royalties in note 16 to the financial statements.

Realized Product Prices – Oil Sands Mining and Upgrading

Realized SCO sales price (\$/bbl) is a non-GAAP ratio calculated as realized SCO sales (non-GAAP financial measure) divided by SCO sales volumes. Realized SCO sales is comprised of crude oil and NGLs sales less blending and feedstock costs, as disclosed in note 16 to the financial statements. The Company considers realized SCO sales price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its SCO sales volumes.

Reconciliations for Oil Sands Mining and Upgrading realized SCO sales and the calculation for realized SCO sales price on a per unit basis are presented below.

(\$ millions, except for bbl/d and \$/bbl)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
SCO sales volumes (bbl/d)	594,042	624,125	602,048
Crude oil and NGLs sales ⁽¹⁾	\$ 5,537	\$ 4,955	\$ 5,879
Less: Blending and feedstock costs ⁽²⁾	743	597	703
Realized SCO sales	\$ 4,794	\$ 4,358	\$ 5,176
Realized SCO sales price (\$/bbl)	\$ 89.68	\$ 75.90	\$ 95.52

(1) Crude oil and NGLs sales in note 16 to the financial statements.

(2) Blending and feedstock costs in note 16 to the financial statements.

Net Capital Expenditures

Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's consolidated statements of cash flows, adjusted for the net change in non-cash working capital, net proceeds from investments, and cash flows from investing activities not included in the Company's capital budget. The Company includes acquisition and disposition capital for property, plant and equipment and exploration and evaluation assets in net capital expenditures at close of the transactions. The Company considers net capital expenditures a key measure in evaluating its performance, as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. A reconciliation of net capital expenditures is presented below.

(\$ millions)	Three Months Ended		
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Cash flows used in investing activities	\$ 1,949	\$ 1,200	\$ 1,312
Net change in non-cash working capital	79	37	(9)
Net capital expenditures	2,028	1,237	1,303
Abandonment expenditures	247	201	188
Capital and abandonment expenditures	\$ 2,275	\$ 1,438	\$ 1,491

Liquidity

Liquidity is a non-GAAP financial measure that represents the availability of readily available undrawn bank credit facilities, cash and cash equivalents, and other highly liquid assets to meet short-term funding requirements and to assist in assessing the Company's financial position. The Company's calculation of liquidity is presented below.

(\$ millions)			
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Undrawn bank credit facilities	\$ 5,358	\$ 5,668	\$ 4,965
Cash and cash equivalents	808	673	93
Liquidity	\$ 6,166	\$ 6,341	\$ 5,058

Long-term Debt, net

Long-term debt, net, is a capital management measure that represents long-term debt, including the current portion of long-term debt, less cash and cash equivalents, as disclosed in note 12 to the financial statements. A reconciliation of the Company's long-term debt, net is presented below.

(\$ millions)			
	Mar 31 2026	Dec 31 2025	Mar 31 2025
Long-term debt	\$ 16,961	\$ 16,617	\$ 17,428
Less: Cash and cash equivalents	808	673	93
Long-term debt, net	\$ 16,153	\$ 15,944	\$ 17,335

Debt to Book Capitalization

Debt to book capitalization is a capital management measure intended to enable financial statement users to evaluate the Company's capital structure, as disclosed in note 12 to the financial statements.

After-Tax Return on Average Capital Employed

After-tax return on average capital employed as defined by the Company is a non-GAAP ratio. The ratio is calculated as net earnings plus after-tax interest and other financing expense for the twelve month trailing period as a percentage of average capital employed (defined as current and long-term debt plus shareholders' equity) for the twelve month trailing period. The Company considers this ratio a key measure in evaluating the Company's ability to generate profit and the efficiency with which it employs capital. A reconciliation of the Company's after-tax return on average capital employed is presented below.

(\$ millions, except ratios)	Mar 31 2026	Dec 31 2025	Mar 31 2025
Interest adjusted after-tax return:			
Net earnings, 12 months trailing ⁽¹⁾	\$ 9,710	\$ 10,820	\$ 7,577
Interest and other financing expense, net of tax, 12 months trailing ⁽²⁾	686	640	546
Interest adjusted after-tax return	\$ 10,396	\$ 11,460	\$ 8,123
12 months average current portion long-term debt ⁽³⁾	\$ 902	\$ 1,293	\$ 1,615
12 months average long-term debt ⁽³⁾	16,169	16,149	11,878
12 months average common shareholders' equity ⁽³⁾	42,242	41,208	39,757
12 months average capital employed	\$ 59,313	\$ 58,650	\$ 53,250
After-tax return on average capital employed	17.5%	19.5%	15.3%

(1) Net earnings, 12 months trailing includes a gain on acquisition, disposition, and remeasurement of \$4,989 million associated with the AOSP asset swap in the fourth quarter of 2025.

(2) The blended tax rate on interest was approximately 23% for each of the periods presented.

(3) For the purpose of this non-GAAP ratio, the measurement of average current and long-term debt and common shareholders' equity are determined on a consistent basis, as an average of the opening and quarterly period end values for the 12 month trailing period for each of the periods presented.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Mar 31 2026	Dec 31 2025
ASSETS			
Current assets			
Cash and cash equivalents		\$ 808	\$ 673
Accounts receivable		5,248	3,999
Inventory		2,921	2,621
Prepays and other		310	301
Current portion of other long-term assets	6	80	70
		9,367	7,664
Exploration and evaluation assets	3	2,735	2,651
Property, plant and equipment	4	78,108	77,645
Lease assets	5	2,951	3,001
Other long-term assets	6	886	869
		\$ 94,047	\$ 91,830
LIABILITIES			
Current liabilities			
Accounts payable		\$ 1,582	\$ 1,105
Accrued liabilities		5,051	4,255
Current income taxes payable		484	597
Current portion of long-term debt	7	441	441
Current portion of other long-term liabilities	8	1,961	1,665
		9,519	8,063
Long-term debt	7	16,520	16,176
Other long-term liabilities	8	12,281	11,936
Deferred income taxes		11,089	11,289
		49,409	47,464
SHAREHOLDERS' EQUITY			
Share capital	10	11,909	11,421
Retained earnings		32,489	32,726
Accumulated other comprehensive income	11	240	219
		44,638	44,366
		\$ 94,047	\$ 91,830

Commitments and contingencies (note 15)

Approved by the Board of Directors on May 6, 2026.

CONSOLIDATED STATEMENTS OF EARNINGS

		Three Months Ended	
(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Mar 31 2026	Mar 31 2025
Product sales	16	\$ 12,404	\$ 12,712
Less: royalties		(1,594)	(1,773)
Revenue		10,810	10,939
Expenses			
Production		2,388	2,372
Blending and feedstock		2,308	2,487
Transportation		670	653
Depletion, depreciation and amortization	4,5	1,877	1,870
Administration		154	152
Share-based compensation	8	644	26
Asset retirement obligation accretion	8	98	91
Interest and other financing expense		318	258
Risk management loss (gain)	14	361	(24)
Foreign exchange loss (gain)		262	(43)
		9,080	7,842
Earnings before taxes		1,730	3,097
Current income tax expense	9	555	511
Deferred income tax (recovery) expense	9	(173)	128
Net earnings		\$ 1,348	\$ 2,458
Net earnings per common share			
Basic	13	\$ 0.65	\$ 1.17
Diluted	13	\$ 0.64	\$ 1.17

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

		Three Months Ended	
(millions of Canadian dollars, unaudited)		Mar 31 2026	Mar 31 2025
Net earnings		\$ 1,348	\$ 2,458
Items that may be reclassified subsequently to net earnings			
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized income during the period, net of taxes of \$nil (2025 – \$nil)		1	4
Reclassification to net earnings, net of taxes of \$nil (2025 – \$1 million)		(2)	(5)
		(1)	(1)
Foreign currency translation adjustment			
Translation of net investment		22	(3)
Other comprehensive income (loss), net of taxes		21	(4)
Comprehensive income		\$ 1,369	\$ 2,454

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

		Three Months Ended	
(millions of Canadian dollars, unaudited)	Note	Mar 31 2026	Mar 31 2025
Share capital	10		
Balance – beginning of period		\$ 11,421	\$ 11,064
Issued upon exercise of stock options		293	112
Previously recognized liability on stock options exercised for common shares		225	136
Purchase of common shares under Normal Course Issuer Bid		(30)	(59)
Balance – end of period		11,909	11,253
Retained earnings			
Balance – beginning of period		32,726	28,103
Net earnings		1,348	2,458
Dividends on common shares	10	(1,304)	(1,233)
Purchase of common shares under Normal Course Issuer Bid, including tax	10	(281)	(433)
Balance – end of period		32,489	28,895
Accumulated other comprehensive income	11		
Balance – beginning of period		219	301
Other comprehensive income (loss), net of taxes		21	(4)
Balance – end of period		240	297
Shareholders' equity		\$ 44,638	\$ 40,445

CONSOLIDATED STATEMENTS OF CASH FLOWS

		Three Months Ended	
(millions of Canadian dollars, unaudited)	Note	Mar 31 2026	Mar 31 2025
Operating activities			
Net earnings		\$ 1,348	\$ 2,458
Non-cash items			
Depletion, depreciation and amortization	4,5	1,877	1,870
Share-based compensation		644	26
Asset retirement obligation accretion		98	91
Unrealized risk management loss	14	316	3
Unrealized foreign exchange loss (gain)		285	(285)
Deferred income tax (recovery) expense		(173)	128
Realized foreign exchange on financing activities ⁽¹⁾		(21)	239
Abandonment expenditures	8	(247)	(188)
Other		(27)	(140)
Net change in non-cash working capital		(818)	82
Cash flows from operating activities		3,282	4,284
Financing activities			
Issuance (repayment) of bank credit facilities and commercial paper, net	7	101	(491)
Repayment of other long-term debt	7	—	(876)
Payment of lease liabilities	5	(101)	(84)
Issuance of common shares on exercise of stock options	10	293	112
Dividends on common shares		(1,224)	(1,184)
Purchase of common shares under Normal Course Issuer Bid	10	(311)	(487)
Cash flows used in financing activities		(1,242)	(3,010)
Investing activities			
Net expenditures on exploration and evaluation assets	3,16	(86)	(6)
Net expenditures on property, plant and equipment	4,16	(2,092)	(1,297)
Proceeds from long-term contract		150	—
Net change in non-cash working capital		79	(9)
Cash flows used in investing activities		(1,949)	(1,312)
Increase (decrease) in cash and cash equivalents			
Opening cash balance prior to restatement for IFRS 9	2	673	131
Adjustment on adoption of IFRS 9	2	44	—
Cash and cash equivalents – beginning of period		717	131
Cash and cash equivalents – end of period		\$ 808	\$ 93
Interest paid on long-term debt		\$ 201	\$ 257
Income taxes paid, net		\$ 663	\$ 685

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

1. ACCOUNTING POLICIES

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

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

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

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855 - 2 Street S.W., Calgary, Alberta, Canada. In June 2026, the Company is relocating its head and registered office to 400 - 4th Avenue S.W., Calgary, AB, T2P 0J4.

These interim consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards"), applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34 "Interim Financial Reporting", following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2025, except as disclosed in note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2025.

Critical Accounting Estimates and Judgements

The Company has made estimates, assumptions, and judgements regarding certain assets, liabilities, revenues, and expenses in the preparation of these interim consolidated financial statements, primarily related to unsettled transactions and events as of the date of these interim consolidated financial statements. Accordingly, actual results may differ from estimated amounts, and those differences may be material.

2. CHANGE IN ACCOUNTING POLICIES

In May 2024, the IASB issued amendments to IFRS 9 "Financial Instruments" and IFRS 7 "Financial Instruments: Disclosures" to clarify the date of recognition and derecognition of some financial assets and liabilities, with a new exception for some financial liabilities settled using an electronic payment system. The amendments also clarify the classification of certain financial assets, and add disclosure requirements for financial instruments with certain contingent features and for equity investments designated at fair value through other comprehensive income. The amendments were effective January 1, 2026. The Company adopted the amendments retrospectively without restating comparative information in the interim consolidated statements of cash flows.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2025	\$ 2,594	\$ —	\$ —	\$ 57	\$ 2,651
Additions/Acquisitions, net	88	—	—	—	88
Transfers to property, plant and equipment	(4)	—	—	—	(4)
At March 31, 2026	\$ 2,678	\$ —	\$ —	\$ 57	\$ 2,735

4. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2025	\$ 92,896	\$ 9,270	\$ 5,316	\$ 60,570	\$ 503	\$ 699	\$ 169,254
Additions/Acquisitions, net	1,705	2	143	342	1	11	2,204
Transfers from exploration and evaluation assets	4	—	—	—	—	—	4
Derecognitions ⁽¹⁾	(94)	(320)	—	(17)	—	—	(431)
Foreign exchange adjustments and other	—	178	97	—	—	—	275
At March 31, 2026	\$ 94,511	\$ 9,130	\$ 5,556	\$ 60,895	\$ 504	\$ 710	\$ 171,306
Accumulated depletion and depreciation							
At December 31, 2025	\$ 65,940	\$ 9,270	\$ 4,035	\$ 11,617	\$ 246	\$ 501	\$ 91,609
Expense	1,095	2	10	653	4	10	1,774
Derecognitions ⁽¹⁾	(94)	(320)	—	(17)	—	—	(431)
Foreign exchange adjustments and other	(3)	178	71	—	—	—	246
At March 31, 2026	\$ 66,938	\$ 9,130	\$ 4,116	\$ 12,253	\$ 250	\$ 511	\$ 93,198
Net book value							
At March 31, 2026	\$ 27,573	\$ —	\$ 1,440	\$ 48,642	\$ 254	\$ 199	\$ 78,108
At December 31, 2025	\$ 26,956	\$ —	\$ 1,281	\$ 48,953	\$ 257	\$ 198	\$ 77,645

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

In February 2026, the Company acquired certain producing and non-producing crude oil and NGLs, and natural gas assets in the Peace River area in the North America Exploration and Production segment for net cash consideration of \$761 million, subject to final closing adjustments. Net assets acquired included exploration and evaluation assets of \$65 million, and property, plant and equipment of \$796 million. The Company also assumed associated asset retirement obligations of \$100 million. No net deferred tax liabilities were recognized on this transaction.

As a result of the acquisition, revenue increased by approximately \$92 million and net operating income (comprised of revenue less production and transportation expense) increased by approximately \$49 million for the three months ended March 31, 2026. Including the impact of depletion, depreciation and amortization, earnings before tax increased by approximately \$34 million for the three months ended March 31, 2026.

If the acquisition had been completed on January 1, 2026, the Company estimates that pro forma revenue would have increased by approximately \$128 million and pro forma net operating income (comprised of revenue less production and transportation expense) would have increased by approximately \$65 million for the three months ended March 31, 2026. Including the impact of depletion, depreciation and amortization, the Company estimates pro forma earnings before taxes would have increased by approximately \$42 million for the three months ended March 31, 2026.

Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have been achieved had the acquisitions actually occurred on January 1, 2026, or of future results. Pro forma results are based on historical information and reflect actual production in the period available for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition dates.

5. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2025	\$ 2,199	\$ 634	\$ 43	\$ 125	\$ 3,001
Additions	—	10	34	8	52
Depreciation	(41)	(48)	(8)	(6)	(103)
Foreign exchange adjustments and other	2	(1)	1	(1)	1
At March 31, 2026	\$ 2,160	\$ 595	\$ 70	\$ 126	\$ 2,951

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at March 31, 2026 were as follows:

	Mar 31 2026	Dec 31 2025
Lease liabilities	\$ 3,059	\$ 3,106
Less: current portion	365	373
	\$ 2,694	\$ 2,733

Total cash outflows for leases for the three months ended March 31, 2026, including payments related to short-term leases not reported as lease assets, were \$392 million (three months ended March 31, 2025 – \$354 million). Interest expense on leases for the three months ended March 31, 2026 was \$34 million (three months ended March 31, 2025 – \$16 million).

6. OTHER LONG-TERM ASSETS

	Mar 31 2026	Dec 31 2025
Long-term prepayments, contracts and other ⁽¹⁾	\$ 456	\$ 419
Prepaid cost of service tolls	223	229
Long-term inventory	287	291
	966	939
Less: current portion	80	70
	\$ 886	\$ 869

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

The Company has a 50% equity investment in NWRP. NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 barrels per day. The refinery processes approximately 50,000 barrels per day of bitumen feedstock, including 12,500 barrels per day of bitumen feedstock for the Company (25% toll payer) and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058 (note 15). Sales of diesel and other refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 16).

The carrying value of the Company's interest in NWRP is \$nil, and as at March 31, 2026, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$471 million (December 31, 2025 – \$496 million). For the three months ended March 31, 2026, the Company's recovery of its share of unrecognized equity losses was \$25 million (three months ended March 31, 2025 – unrecognized equity loss of \$19 million).

7. LONG-TERM DEBT

	Mar 31 2026	Dec 31 2025
Canadian dollar denominated debt, unsecured		
Medium-term notes	\$ 3,116	\$ 3,116
US dollar denominated debt, unsecured		
Bank credit facilities (March 31, 2026 – US\$2,932 million; December 31, 2025 – US\$2,860 million)	4,092	3,922
US dollar debt securities (March 31, 2026 – US\$7,050 million; December 31, 2025 – US\$7,050 million)	9,838	9,669
	17,046	16,707
Less: original issue discounts, net ⁽¹⁾	13	14
transaction costs ^{(1) (2)}	72	76
	16,961	16,617
Less: current portion of long-term debt ^{(1) (2)}	441	441
	\$ 16,520	\$ 16,176

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

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

Bank Credit Facilities and Commercial Paper

As at March 31, 2026, the Company had undrawn bank credit facilities of \$5,358 million, and a fully drawn non-revolving term credit facility of \$4,000 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit.

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

During the first quarter of 2026, the Company cancelled the \$140 million portion of its \$2,565 million revolving syndicated credit facility, maturing June 2027, reducing the capacity to \$2,425 million, with a maturity of June 2029.

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

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

The Company's weighted average interest rate on bank credit facilities outstanding as at March 31, 2026 was 4.9% (March 31, 2025 – 5.3%), and on total long-term debt outstanding for the three months ended March 31, 2026 was 4.9% (March 31, 2025 – 5.0%).

As at March 31, 2026, letters of credit and guarantees aggregating to \$954 million were outstanding (December 31, 2025 – \$840 million).

Medium-Term Notes

In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to \$3,000 million of medium-term notes in Canada, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at March 31, 2026, the Company had \$1,350 million remaining on its base shelf prospectus.

US Dollar Debt Securities

In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US\$4,500 million of debt securities in the United States, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at March 31, 2026, the Company had US\$3,003 million remaining on its base shelf prospectus.

8. OTHER LONG-TERM LIABILITIES

	Mar 31 2026	Dec 31 2025
Asset retirement obligations	\$ 9,757	\$ 9,743
Lease liabilities (note 5)	3,059	3,106
Share-based compensation	794	433
Risk management (note 14)	381	65
Transportation and processing contracts	180	186
Other	71	68
	14,242	13,601
Less: current portion	1,961	1,665
	\$ 12,281	\$ 11,936

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 4.9% (December 31, 2025 – 4.9%) and inflation rates of up to 2% (December 31, 2025 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Mar 31 2026	Dec 31 2025
Balance – beginning of period	\$ 9,743	\$ 8,607
Liabilities incurred	11	34
Liabilities acquired, net	101	489
Liabilities settled	(247)	(771)
Asset retirement obligation accretion	98	380
Revision of cost, inflation, and timing estimates ⁽¹⁾	—	1,233
Change in discount rates	—	(129)
Foreign exchange adjustments	51	(100)
Balance – end of period	9,757	9,743
Less: current portion	1,007	956
	\$ 8,750	\$ 8,787

(1) Includes normal course revisions of cost, inflation, and timing estimates, as well as revisions to decommissioning timing and cost estimates in the North Sea and Offshore Africa at December 31, 2025.

Share-Based Compensation

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

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

	Mar 31 2026	Dec 31 2025
Balance – beginning of period	\$ 433	\$ 620
Share-based compensation expense	644	180
Cash payment for stock options surrendered and PSUs vested	(58)	(94)
Transferred to common shares	(225)	(273)
Balance – end of period	794	433
Less: current portion	559	312
	\$ 235	\$ 121

9. INCOME TAXES

The provision for income tax was as follows:

Expense (recovery)	Three Months Ended	
	Mar 31 2026	Mar 31 2025
Current corporate income tax – North America ⁽¹⁾	\$ 671	\$ 569
Current corporate income tax – North Sea	(53)	(26)
Current corporate income tax – Offshore Africa	—	5
Current PRT ⁽²⁾ – North Sea	(65)	(39)
Other taxes	2	2
Current income tax	555	511
Deferred corporate income tax	(59)	119
Deferred PRT ⁽²⁾ – North Sea	(114)	9
Deferred income tax	(173)	128
Income tax	\$ 382	\$ 639

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

(2) Petroleum Revenue Tax.

10. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued Common Shares	Three Months Ended Mar 31, 2026	
	Number of shares (thousands)	Amount
Balance – beginning of period	2,081,578	\$ 11,421
Issued upon exercise of stock options	9,557	293
Previously recognized liability on stock options exercised for common shares	—	225
Purchase of common shares under Normal Course Issuer Bid	(5,425)	(30)
Balance – end of period	2,085,710	\$ 11,909

Dividends

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

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

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

Normal Course Issuer Bid

On March 10, 2026, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 182,396,564 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2026 and ending March 12, 2027, subject to applicable securities laws.

For the three months ended March 31, 2026, the Company purchased 5,425,000 common shares at a weighted average price of \$57.26 per common share for a total cost, including tax, of \$311 million. Retained earnings were reduced by \$281 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2026, up to and including May 5, 2026, the Company purchased 5,650,000 common shares at a weighted average price of \$63.19 per common share for a total cost, including tax, of \$360 million.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding as at March 31, 2026:

	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of period	54,734	\$ 39.83
Granted	16,938	55.27
Exercised for common shares	(9,557)	30.73
Surrendered for cash settlement	(2,253)	38.05
Forfeited	(571)	41.05
Outstanding – end of period	59,291	\$ 45.76
Exercisable – end of period	8,659	\$ 40.40

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

11. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Mar 31 2026	Mar 31 2025
Derivative financial instruments designated as cash flow hedges	\$ 65	\$ 69
Foreign currency translation adjustment	175	228
	\$ 240	\$ 297

12. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the ratio of current and long-term debt less cash and cash equivalents divided by the sum of the carrying value of shareholders' equity plus current and long-term debt less cash and cash equivalents. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. As at March 31, 2026, the ratio was within the target range at 26.6%.

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

	Mar 31 2026	Dec 31 2025
Long-term debt	\$ 16,961	\$ 16,617
Less: cash and cash equivalents	808	673
Long-term debt, net	\$ 16,153	\$ 15,944
Total shareholders' equity	\$ 44,638	\$ 44,366
Debt to book capitalization	26.6%	26.4%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at March 31, 2026, the Company was in compliance with this covenant.

13. NET EARNINGS PER COMMON SHARE

	Three Months Ended	
	Mar 31 2026	Mar 31 2025
Weighted average common shares outstanding – basic (thousands of shares)	2,084,519	2,100,540
Effect of dilutive stock options (thousands of shares)	11,596	8,537
Weighted average common shares outstanding – diluted (thousands of shares)	2,096,115	2,109,077
Net earnings	\$ 1,348	\$ 2,458
Net earnings per common share – basic	\$ 0.65	\$ 1.17
– diluted	\$ 0.64	\$ 1.17

14. FINANCIAL INSTRUMENTS

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

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

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

Asset (liability)	Mar 31 2026	Dec 31 2025
Balance – beginning of period	\$ (65)	\$ 5
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities ^{(1) (2) (3) (4)}	(316)	(68)
Foreign exchange	—	(1)
Other comprehensive income	—	(1)
Balance – end of period	(381)	(65)
Less: current portion	(12)	(8)
	\$ (369)	\$ (57)

(1) Risk management liabilities are disclosed in note 8.

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

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

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

Net loss (gain) from risk management activities was as follows:

	Three Months Ended	
	Mar 31 2026	Mar 31 2025
Net realized risk management loss (gain)	\$ 45	\$ (27)
Net unrealized risk management loss	316	3
	\$ 361	\$ (24)

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

	Mar 31, 2026	
	Carrying amount	Level 1 Fair Value
Fixed rate long-term debt ^{(1) (2)}	\$ 12,869	\$ 13,047

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

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

Embedded Derivative

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

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

The Company recognizes a loss (gain) on risk management activities in the statements of earnings related to its natural gas embedded derivative. The loss (gain) is determined by the relative movements in fair value compared to the prior period. For the three months ended March 31, 2026, the Company recognized an unrealized risk management loss of \$312 million on the natural gas embedded derivative. As at March 31, 2026, the fair value of the embedded derivative was a liability of \$369 million (December 31, 2025 – \$57 million liability).

The Level 3 fair value measurements of the embedded derivative could be materially impacted by a change in the discount rate and movements in natural gas prices. The following table summarizes the impacts to the fair value of the embedded derivative resulting from changes in the specified variable over the 15-year contract. These sensitivities as at March 31, 2026 are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities.

	JKM price		Discount rate	
	US\$0.10/MMBtu increase	US\$0.10/MMBtu decrease	1% increase	1% decrease
Fair value – increase/(decrease)	\$ 53	\$ (53)	\$ (56)	\$ 66

Financial Risk Factors

The Company's financial risks are consistent with those discussed in notes 1, 3 and 18 of the Company's audited consolidated financial statements for the year ended December 31, 2025.

a) Market risk

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

Commodity price risk management

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

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. As at March 31, 2026, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

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

As at March 31, 2026, the Company had US\$1,502 million of foreign currency forward contracts outstanding (December 31, 2025 – US\$1,500 million), with original terms of up to 90 days, all of which were designated as derivatives held for trading (December 31, 2025 – US\$1,500 million).

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and, where appropriate, ensuring that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at March 31, 2026, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

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

As at March 31, 2026, the maturity dates of the Company's financial liabilities were as follows:

		Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	\$	1,582	\$ —	\$ —	\$ —
Accrued liabilities	\$	5,051	\$ —	\$ —	\$ —
Long-term debt ⁽¹⁾	\$	441	\$ 6,061	\$ 2,844	\$ 7,700
Other long-term liabilities ^{(2) (3)}	\$	377	\$ 278	\$ 639	\$ 2,248
Interest and other financing expense ⁽⁴⁾	\$	981	\$ 863	\$ 1,861	\$ 3,562

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

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, \$365 million; one to less than two years, \$278 million; two to less than five years, \$639 million; and thereafter, \$1,777 million.

(3) Includes a gross derivative liability of \$471 million associated with the Company's natural gas embedded derivative. The gross liability is offset by a gross derivative asset of \$102 million, resulting in a net liability of \$369 million.

(4) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at March 31, 2026.

15. COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at March 31, 2026:

	Remaining 2026	2027	2028	2029	2030	Thereafter
Product transportation, purchases, and processing ⁽¹⁾	\$ 1,729	\$ 2,279	\$ 2,135	\$ 1,977	\$ 1,816	\$ 18,169
North West Redwater Partnership service toll ⁽²⁾	\$ 81	\$ 95	\$ 96	\$ 95	\$ 95	\$ 3,865
Offshore vessels and decommissioning equipment	\$ 179	\$ —	\$ —	\$ —	\$ —	\$ —
Field equipment and supplies	\$ 123	\$ 122	\$ 121	\$ 24	\$ 24	\$ 170
Office leases and other	\$ 219	\$ 66	\$ 19	\$ 18	\$ 18	\$ 176

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

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is \$1,764 million of interest payable over the 40-year tolling period, ending in 2058 (note 6).

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

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

16. SEGMENTED INFORMATION

	North America		North Sea		Offshore Africa		Total Exploration and Production	
	Three Months Ended		Three Months Ended		Three Months Ended		Three Months Ended	
	Mar 31		Mar 31		Mar 31		Mar 31	
(millions of Canadian dollars, unaudited)	2026	2025	2026	2025	2026	2025	2026	2025
Segmented product sales								
Crude oil and NGLs ⁽¹⁾	\$ 5,389	\$ 5,366	\$ 36	\$ 152	\$ —	\$ 106	\$ 5,425	\$ 5,624
Natural gas ⁽¹⁾	796	671	2	6	—	13	798	690
Other income and revenue	47	17	—	—	—	1	47	18
Total segmented product sales	6,232	6,054	38	158	—	120	6,270	6,332
Less: royalties	(781)	(781)	—	—	—	(5)	(781)	(786)
Segmented revenue	5,451	5,273	38	158	—	115	5,489	5,546
Segmented expenses								
Production	1,006	894	35	170	—	35	1,041	1,099
Blending and feedstock	1,248	1,391	—	—	—	—	1,248	1,391
Transportation	524	476	2	3	—	—	526	479
Depletion, depreciation and amortization	1,131	1,092	6	40	14	59	1,151	1,191
Asset retirement obligation accretion	55	53	20	14	2	2	77	69
Risk management loss (gain) (commodity derivatives)	317	(12)	—	—	—	—	317	(12)
Total segmented expenses	4,281	3,894	63	227	16	96	4,360	4,217
Segmented earnings (loss)	\$ 1,170	\$ 1,379	\$ (25)	\$ (69)	\$ (16)	\$ 19	\$ 1,129	\$ 1,329
Non-segmented expenses								
Administration								
Share-based compensation								
Interest and other financing expense								
Risk management loss (gain) (other)								
Foreign exchange loss (gain)								
Total non-segmented expenses								
Earnings before taxes								
Current income tax								
Deferred income tax								
Net earnings								

	Oil Sands Mining and Upgrading		Midstream and Refining		Inter-segment Elimination and Other		Total	
	Three Months Ended		Three Months Ended		Three Months Ended		Three Months Ended	
	Mar 31		Mar 31		Mar 31		Mar 31	
(millions of Canadian dollars, unaudited)	2026	2025	2026	2025	2026	2025	2026	2025
Segmented product sales								
Crude oil and NGLs ⁽¹⁾ ⁽²⁾	\$ 5,537	\$ 5,879	\$ 23	\$ 22	\$ 129	\$ 207	\$ 11,114	\$ 11,732
Natural gas ⁽¹⁾	—	—	—	—	34	26	832	716
Other income and revenue	134	25	277	221	—	—	458	264
Total segmented product sales	5,671	5,904	300	243	163	233	12,404	12,712
Less: royalties	(813)	(987)	—	—	—	—	(1,594)	(1,773)
Segmented revenue	4,858	4,917	300	243	163	233	10,810	10,939
Segmented expenses								
Production	1,269	1,185	63	73	15	15	2,388	2,372
Blending and feedstock ⁽²⁾	743	703	170	172	147	221	2,308	2,487
Transportation	139	174	4	4	1	(4)	670	653
Depletion, depreciation and amortization	722	675	4	4	—	—	1,877	1,870
Asset retirement obligation accretion	21	22	—	—	—	—	98	91
Risk management loss (gain) (commodity derivatives)	—	—	—	—	—	—	317	(12)
Total segmented expenses	2,894	2,759	241	253	163	232	7,658	7,461
Segmented earnings (loss)	\$ 1,964	\$ 2,158	\$ 59	\$ (10)	\$ —	\$ 1	\$ 3,152	\$ 3,478
Non-segmented expenses								
Administration							154	152
Share-based compensation							644	26
Interest and other financing expense							318	258
Risk management loss (gain) (other)							44	(12)
Foreign exchange loss (gain)							262	(43)
Total non-segmented expenses							1,422	381
Earnings before taxes							1,730	3,097
Current income tax							555	511
Deferred income tax							(173)	128
Net earnings							\$ 1,348	\$ 2,458

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

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

Capital Expenditures ⁽¹⁾

Three Months Ended						
	Mar 31, 2026			Mar 31, 2025		
	Net expenditures	Non-cash and fair value changes ⁽²⁾	Capitalized costs	Net expenditures	Non-cash and fair value changes ⁽²⁾	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	\$ 86	\$ (2)	\$ 84	\$ 7	\$ 8	\$ 15
Offshore Africa	—	—	—	(1)	—	(1)
	86	(2)	84	6	8	14
Property, plant and equipment						
Exploration and Production						
North America	1,593	22	1,615	829	(139)	690
North Sea	2	(320)	(318)	3	—	3
Offshore Africa	143	—	143	128	—	128
	1,738	(298)	1,440	960	(139)	821
Oil Sands Mining and Upgrading	342	(17)	325	319	(66)	253
Midstream and Refining	1	—	1	2	—	2
Head Office	11	—	11	16	—	16
	2,092	(315)	1,777	1,297	(205)	1,092
	\$ 2,178	\$ (317)	\$ 1,861	\$ 1,303	\$ (197)	\$ 1,106

(1) This table provides a reconciliation of capitalized costs, reported in note 3 and note 4, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

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

Segmented Assets

	Mar 31 2026	Dec 31 2025
Exploration and Production		
North America	\$ 34,884	\$ 33,462
North Sea	688	789
Offshore Africa	1,564	1,398
Other	59	35
Oil Sands Mining and Upgrading	55,202	54,699
Midstream and Refining	1,341	1,142
Head Office	309	305
	\$ 94,047	\$ 91,830

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated August 2025. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended March 31, 2026:

Interest coverage (times)	
Net earnings ⁽¹⁾	14.3x
Adjusted funds flow ⁽²⁾	20.3x

(1) Net earnings plus income taxes and interest expense; divided by interest expense.

(2) Adjusted funds flow (as defined in the Company's Management's Discussion and Analysis), plus current income taxes and interest expense; divided by interest expense.

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CORPORATE INFORMATION

Board of Directors

Catherine M. Best, F.C.A, ICD.D
Shelley A. M. Brown, C.M., F.C.P.A, F.C.A, ICD.D
M. Elizabeth Cannon, Ph.D, O.C.
N. Murray Edwards, C.M.
Christopher L. Fong
Ambassador Gordon D. Giffin
Wilfred A. Gobert
Christine M. Healy
Steve W. Laut
Honourable Frank J. McKenna, P.C., O.C., O.N.B., K.C.
Scott G. Stauth
David A. Tuer
Annette M. Verschuren, O.C.

Officers

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Executive Chairman
Scott G. Stauth
President
Robin S. Zabek
Chief Operating Officer, Exploration and Production
Jay E. Froc
Chief Operating Officer, Oil Sands
Ron K. Laing
Chief Commercial and Corporate Development Officer
Victor C. Darel
Chief Financial Officer
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Senior Vice-President, Canadian Conventional Field Operations
Calvin J. Bast
Senior Vice-President, Production
Dwayne F. Giggs
Senior Vice-President, Exploration
Dean W. Halewich
Senior Vice-President, Safety, Risk Management and Innovation
Sheryl L. Kapeluck
Senior Vice-President, Finance
Devin C. Lowe
Senior Vice-President, Exploitation
Warren P. Raczynski
Senior Vice-President, Thermal
Kara L. Slemko
Senior Vice-President, Commercial Operations and Corporate Development
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Senior Vice-President, Oil Sands Mining and Upgrading
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Vice-President, Legal and General Counsel
Erin L. Lunn
Vice-President, Land
Mark A. Overwater
Vice-President, Marketing
Kyle G. Pisio
Vice-President, Drilling, Completions and Asset Retirement
Stephanie A. Graham
Corporate Secretary and Associate General Counsel, Canada

CNR International (U.K.) Limited Aberdeen, Scotland

Barry Duncan
Managing Director and
Vice-President, Finance, International

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ
New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

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