CANADIAN NATURAL RESOURCES LIMITED
2025 FOURTH QUARTER AND YEAR END RESULTS

Canadian Natural's President, Scott Stauth, commented on the Company's fourth quarter and year end 2025 results, "The year 2025 was the best operational year in the Company's long history of maximizing value for our shareholders. We set several production records, lowered our operating costs and capital expenditures came in under our forecast. We grew organically and completed several accretive acquisitions, including the Palliser Block assets in southern Alberta and liquids-rich Montney assets in the Grande Prairie area, along with increasing our ownership in the Albian mines to 100% through an asset swap. As a result, we achieved record annual production of 1,571 MBOE/d in 2025, resulting in year-over-year growth of 15% or approximately 207 MBOE/d from 2024 levels. We also achieved record annual liquids production of 1,146 Mbbl/d, of which 65% was comprised of Synthetic Crude Oil ("SCO"), light crude oil and NGLs, which are not subject to widening heavy crude oil differentials.

Strong execution across our large, diverse asset base continues to provide significant opportunities to create shareholder value in 2026 and beyond. This is evident by our increased production, strong free cash flow and growth in reserves achieved in 2025, through organic growth and accretive acquisitions. These successes provided the Board of Directors with the confidence to approve a dividend increase and an enhancement to our direct shareholder returns, by adjusting our net debt targets as a part of our free cash flow allocation policy. Additionally, we are decreasing our 2026 operating capital forecast by approximately $310 million, following the completion of a strategic acquisition early in 2026, and increasing our 2026 production guidance range to 1,615 MBOE/d and 1,665 MBOE/d from the previous guidance range of 1,590 MBOE/d and 1,650 MBOE/d.

Canadian Natural's reserves are significant when compared to other major oil companies, which support long-term organic growth opportunities. Year end 2025 total proved reserves of 15.91 billion BOE and total proved plus probable reserves of 20.75 billion BOE represent increases of approximately 4% and 3%, respectively, from year end 2024 levels. With approximately 73% of the Company's total proved reserves being long life low decline, the strength and depth of our assets is evident and provide us with a total proved reserves life index ("RLI") of 31 years and a total proved plus probable RLI of 40 years. We continue to deliver strong total proved Finding, Development and Acquisition ("FD&A") costs, including changes in Future Development Cost ("FDC"), achieving an industry leading FD&A in 2025 of $3.64/BOE for total proved reserves and $2.42/BOE for total proved plus probable reserves."

Canadian Natural's Chief Financial Officer, Victor Darel, added "In 2025, we generated adjusted net earnings of $7.4 billion or $3.56 per share, and adjusted funds flow of $15.5 billion or $7.39 per share. Throughout the year, we completed several accretive acquisitions, increasing production and cash flow, while reducing net debt by approximately $2.7 billion to just under $16 billion at year end 2025. We returned approximately $9.0 billion to our shareholders in 2025, including $4.9 billion in dividends, $1.4 billion in share repurchases and $2.7 billion in net debt reduction. Subsequent to year end, the Board approved an approximate 6.4% increase to our quarterly dividend, bringing the annualized dividend up to $2.50 per common share. This marks 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.

Additionally, the Board of Directors have, effective January 1, 2026, adjusted the net debt target levels in our free cash flow allocation policy which results in an acceleration of the next increase to direct shareholder returns. Now, when net debt falls below $16 billion, compared to our previous target of $15 billion, we will increase direct shareholder returns in the form of share repurchases to 75% of free cash flow generated, managed on a forward-looking basis.

Our financial flexibility and long life low decline asset base provide a strong foundation and a competitive advantage with low maintenance capital requirements. Our US$ WTI breakeven remains top tier in the low to mid-$40 per barrel range. Our balance sheet is strong with significant liquidity of approximately $6.3 billion at year end 2025. Our excellent results highlight the cash flow generating capability of our top tier asset base with strong year end metrics including Debt to Book Capitalization at 26% and Debt to Adjusted EBITDA at 0.7x."

2025 ANNUAL HIGHLIGHTS

- Generated net earnings of approximately $10.8 billion and adjusted net earnings from operations of $7.4 billion.
- Generated adjusted funds flow of approximately $15.5 billion.
- Returns to shareholders totaled approximately $9.0 billion, comprised of $4.9 billion in dividends, $1.4 billion in share repurchases and $2.7 billion through reduction in the Company's net debt.
  - Approximately 33.5 million common shares were repurchased and cancelled in 2025 at a weighted average price of $43.28 per share.
- Record total annual production of approximately 1,571,000 BOE/d, an increase of 207,000 BOE/d or 15% from 2024 levels.
  - Record total liquids production of approximately 1,146,000 bbl/d, an increase of 141,000 bbl/d or 14% from 2024 levels.
    - Strong total corporate liquids operating costs[1] of $18.44/bbl (US$13.19/bbl), compared to $18.56/bbl (US$13.55/bbl) in 2024.
    - Record Oil Sands Mining and Upgrading production of approximately 565,000 bbl/d of zero decline SCO, with upgrader utilization of 100%, including the planned turnaround at the Athabasca Oil Sands Project ("AOSP").
      - Industry leading Oil Sands Mining and Upgrading operating costs of $22.66/bbl (US$16.21/bbl), compared to $22.88/bbl (US$16.70/bbl) in 2024.
    - Record thermal in situ production of 275,000 bbl/d of long life low decline production.
  - Record natural gas production of 2,547 MMcf/d, an increase of 400 MMcf/d or 19% from 2024 levels.
- Canadian Natural reduced net debt by approximately $2.7 billion from 2024 year end levels.
  - Repaid US$1.2 billion of US dollar debt securities.
  - Issued C$1.65 billion in 3, 5 and 10 year medium-term notes.

2025 FOURTH QUARTER HIGHLIGHTS

- Generated net earnings of approximately $5.3 billion and adjusted net earnings from operations of $1.7 billion.
- Generated adjusted funds flow of approximately $3.7 billion.
- Returns to shareholders totaled approximately $2.7 billion, comprised of $1.2 billion in dividends, $0.3 billion in share repurchases and $1.2 billion through reduction in the Company's net debt.
- Record total quarterly production of approximately 1,659,000 BOE/d, an increase of 188,000 BOE/d or 13% from Q4/24 levels.
  - Record total liquids production of approximately 1,215,000 bbl/d, an increase of 125,000 bbl/d or 12% from Q4/24 levels.
    - Record Oil Sands Mining and Upgrading production of approximately 620,000 bbl/d of zero decline SCO with upgrader utilization of 105%.
      - Industry leading Oil Sands Mining and Upgrading operating costs of $21.84/bbl (US$15.66/bbl).
- On November 1, 2025, Canadian Natural closed the AOSP asset swap with Shell and now owns and operates 100% of the Albian oil sands mines and associated reserves.
  - The transaction added approximately 31,000 bbl/d of annual, zero decline bitumen production to our Oil Sands Mining and Upgrading portfolio.

(1) Operating costs are calculated as production expense divided by respective sales volumes. Natural gas and NGLs production volumes approximate sales volumes.

ACCELERATING SHAREHOLDER RETURNS WITH REVISED FREE CASH FLOW ALLOCATION POLICY

As a result of the Company's continued strong execution and resilience to volatile commodity prices, combined with continued growth of production, cash flow and reserves through strategic acquisitions and organic development, Canadian Natural is increasing its annual dividend and enhancing direct shareholder returns by updating its net debt targets within the Company's free cash flow allocation policy. The policy was last adjusted in October 2024, when on a proforma basis, including the acquired Chevron assets, annual production was approximately 1,465,000 BOE/d. Since then, through organic growth and strategic acquisitions, annual production has grown by approximately 12% or 175,000 BOE/d, to the mid-point of updated 2026 guidance.

- The Board of Directors have approved an approximate 6.4% increase to the quarterly cash dividend to $0.625 per common share, from $0.5875 per common share, payable on April 7, 2026 to shareholders of record at the close of business on March 20, 2026.
  - This dividend increase represents an annualized dividend of $2.50 per common share and demonstrates 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.
    - Canadian Natural's leading track record of 26 consecutive years of dividend growth continues with a CAGR of 20% over that time.
- The Company's free cash flow allocation policy has been revised based upon the increase in the Company's reserves and production from when it was last reviewed in 2024.
  - When net debt is at or above $16 billion (formerly $15 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 (formerly $12 billion) and $16 billion (formerly $15 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 (formerly $12 billion), 100% of free cash flow will be allocated to direct shareholder returns in the form of share repurchases.
  - 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.
  - Free cash flow is calculated as adjusted funds flow less dividends on common shares, net capital expenditures and abandonment expenditures.
- On March 4, 2026, the Board of Directors approved the renewal of the Company's Normal Course Issuer Bid ("NCIB"), which states that during the 12 month period commencing on March 13, 2026 and ending on March 12, 2027, the Company can repurchase for cancellation up to 10% of the public float (as determined in accordance with the rules of the TSX), subject to TSX approval.

UPDATED 2026 GUIDANCE

- Canadian Natural is utilizing its capital flexibility in 2026 by reducing forecasted Operating Capital Expenditures by approximately $310 million, which reflects continuous improvement and efficiency gains on our development program and a deferral of front-end engineering and design ("FEED") capital on our Jackpine mine expansion opportunity at Albian.
  - As first communicated at the Company's 2025 investor day held on November 7, 2025, Canadian Natural continues to progress on its budgeted defined short-term growth strategy through the development of its Conventional E&P assets and thermal drill to fill pad additions, and its medium-term growth strategy by expending FEED capital on both its 70,000 bbl/d Pike 2 growth project and 30,000 bbl/d Jackfish expansion project.
  - As a part of its long-term growth strategy, the Company is deferring FEED and defined capital for our Oil Sands Jackpine mine expansion opportunity at Albian, that was originally included in our 2026 capital budget. This approximately $8.25 billion project is being deferred due to the lack of finalization of government regulatory policies as it relates to carbon pricing and methane, which creates uncertainty and economic burden for long-term growth investments. Once there is more certainty on these regulatory policies, approval timelines and egress, we will reassess the viability of this project.
  - Additionally, subsequent to year end, Canadian Natural has acquired assets in the Peace River area of Alberta, which are adjacent to existing operations in the area, and elsewhere for approximately $765 million.
  - As a result, forecasted annual capital is being updated as follows:

Capital Expenditures[(1)] ($ millions)	2026 Budget	**2026 Updated Forecast**	Change
Conventional E&P	$ 3,320	**$ 3,160**	$ (160)
Thermal and Oil Sands Mining & Upgrading	$ 2,980	**$ 2,830**	$ (150)
Total Operating Capital Expenditures	$ 6,300	**$ 5,990**	$ (310)
Carbon Capture	$ 125	**$ 125**	$ —
Net acquisitions	$ —	**$ 765**	$ 765
Total Capital Expenditures	$ 6,425	**$ 6,880**	$ 455

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

Note: 2026 capital expenditures excludes approximately $993 million of abandonment expenditures, before recoveries, related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea.

- Following the recent acquisition, Canadian Natural is increasing its 2026 production guidance range to 1,615 MBOE/d and 1,665 MBOE/d, with the mid-point being 20 MBOE/d higher than the budget.

Production Guidance[(1)] (before royalties)	2026 Budget	**2026 Updated Forecast**
Natural Gas (MMcf/d)	2,477 - 2,577	**2,560 - 2,615**
Conventional E&P Crude Oil & NGLs (Mbbl/d)	325 - 337	**336 - 346**
Thermal and Oil Sands Mining & Upgrading (Mbbl/d)	852 - 883	**852 - 883**
Total Liquids (Mbbl/d)	1,177 - 1,220	**1,188 - 1,229**
Total MBOE/d	1,590 - 1,650	**1,615 - 1,665**

(1) Reflects planned downtime for turnaround activities in all areas.

Note: Rounded to the nearest 1,000 bbl/d.

HIGHLIGHTS

($ millions, except per common share amounts)		Three Months Ended Dec 31 2025	Sep 30 2025	Dec 31 2024	Year Ended Dec 31 2025	Dec 31 2024
Net earnings		**$ 5,303**	$ 600	$ 1,138	**$ 10,820**	$ 6,106
Per common share	– basic	**$ 2.55**	$ 0.29	$ 0.54	**$ 5.17**	$ 2.87
	– diluted	**$ 2.54**	$ 0.29	$ 0.54	**$ 5.16**	$ 2.85
Adjusted net earnings from operations (1)		**$ 1,711**	$ 1,801	$ 1,977	**$ 7,444**	$ 7,414
Per common share	– basic (2)	**$ 0.82**	$ 0.86	$ 0.94	**$ 3.56**	$ 3.49
	– diluted (2)	**$ 0.82**	$ 0.86	$ 0.93	**$ 3.55**	$ 3.46
Cash flows from operating activities		**$ 3,768**	$ 3,940	$ 3,432	**$ 15,106**	$ 13,386
Adjusted funds flow (1)		**$ 3,748**	$ 3,920	$ 4,186	**$ 15,460**	$ 14,859
Per common share	– basic (2)	**$ 1.80**	$ 1.88	$ 1.99	**$ 7.39**	$ 6.99
	– diluted (2)	**$ 1.79**	$ 1.87	$ 1.97	**$ 7.37**	$ 6.94
Cash flows used in investing activities		**$ 1,200**	$ 2,234	$ 10,414	**$ 6,687**	$ 14,095
Net capital expenditures (1)		**$ 1,237**	$ 2,124	$ 10,348	**$ 6,579**	$ 14,431
Net capital expenditures (1), excluding net acquisitions (3)		**$ 1,413**	$ 1,318	$ 1,290	**$ 5,707**	$ 5,286
Abandonment expenditures		**$ 201**	$ 189	$ 151	**$ 771**	$ 646
Daily production, before royalties						
Natural gas (MMcf/d)		**2,660**	2,668	2,283	**2,547**	2,147
Crude oil and NGLs (bbl/d)		**1,215,364**	1,175,604	1,090,002	**1,146,175**	1,005,603
Equivalent production (BOE/d) (4)		**1,658,681**	1,620,261	1,470,428	**1,570,757**	1,363,496

(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) Includes the impact of cash paid and received related to acquisitions and dispositions. The Company received net cash consideration of $212 million related to the AOSP asset swap in Q4/25. Refer to the 'Net Capital Expenditures' table in the Company's MD&A.

(4) 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 $10.8 billion in 2025 reflected strong operational performance, as well as the impact of non-cash accounting gains on the AOSP asset swap that closed in Q4/25, together with non-cash recoverability charges related to the North Sea and Offshore Africa. These items are discussed in detail in the Q4/25 Financial Statements and MD&A.
  - Adjusted net earnings from operations was strong at $7.4 billion in 2025.

RESERVES HIGHLIGHTS

A key differentiator for Canadian Natural is the strength, diversity and balance of its world class, top tier assets. The Company's total proved reserve life index ("RLI")[1] of 31 years is supported by long life low decline assets that have been strategically assembled and developed over several decades. The low maintenance capital requirements relative to the size and quality of the reserves affords the Company significant flexibility when balancing its four pillars of capital allocation to maximize shareholder value.

The Company's reserves were evaluated and reviewed by Independent Qualified Reserves Evaluators ("IQREs"). The following highlights are based on the Company's reserves using forecast prices and costs at December 31, 2025 (all reserves values are Company Gross unless stated otherwise).

- Total proved reserves increased 4% to 15.910 billion BOE, with reserves additions and revisions of 1.253 billion BOE. Total proved plus probable reserves increased 3% to 20.750 billion BOE, with reserves additions and revisions of 1.213 billion BOE.
  - The strength and depth of the Company's assets are evident as approximately 73% of total proved reserves are long life low decline reserves. This results in a total proved BOE RLI of 31 years and a total proved plus probable BOE RLI of 40 years.
    - Additionally, high value, zero decline SCO and bitumen from the Horizon and Albian mines represent approximately 50% of total proved reserves with a RLI of 39 years.
- Proved developed producing reserves additions and revisions for 2025 were 1.129 billion BOE, replacing 2025 production by 197%. The proved developed producing BOE RLI is 20 years.
- Total proved reserves additions and revisions for 2025 replaced 2025 production by 218%. Total proved plus probable reserves additions and revisions for 2025 replaced 2025 production by 212%.
- In 2025, Canadian Natural continued to achieve strong Finding, Development and Acquisition ("FD&A") costs:
  - FD&A costs, including changes in Future Development Cost ("FDC"), are $3.64/BOE for total proved reserves and $2.42/BOE for total proved plus probable reserves.
- The net present value of future net revenues, before income tax, discounted at 10%, is $110.1 billion for proved developed producing reserves, $157.8 billion for total proved reserves, and $191.0 billion for total proved plus probable reserves.

(1) Supplementary financial measure. Refer to the '2025 Year End Reserves' section of this document.

OPERATIONS REVIEW

North America Oil Sands Mining and Upgrading

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Synthetic crude oil production (bbl/d) (1)(2)	**619,901**	581,136	534,631	**565,102**	472,245

(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 achieved record annual production in 2025, averaging 565,102 bbl/d of SCO, an increase of 20% or approximately 93,000 bbl/d from 2024 levels, reflecting the additional working interests acquired in AOSP, combined with effective and efficient operations.
  - Oil Sands Mining and Upgrading achieved strong annual upgrader utilization, averaging 100% in 2025, which included a planned turnaround at AOSP.
  - Industry leading Oil Sands Mining and Upgrading operating costs averaged $22.66/bbl (US$16.21/bbl) of SCO in 2025, compared to $22.88/bbl (US$16.70/bbl) in 2024.
  - Oil Sands Mining and Upgrading production has strong realized pricing, averaging $86.41/bbl in 2025.
- 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.
- As a part of its long-term growth strategy, the Company is deferring FEED and defined capital for our Oil Sands Jackpine mine expansion opportunity at Albian, that was originally included in our 2026 capital budget. This approximately $8.25 billion project is being deferred due to the lack of finalization of government regulatory policies as it relates to carbon pricing and methane, which creates uncertainty and economic burden for long-term growth investments. Once there is more certainty on these regulatory policies, approval timelines and egress, we will reassess the viability of this project.

North America Exploration and Production

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Bitumen production (bbl/d)	**266,308**	274,752	276,231	**275,086**	271,011
Net bitumen wells drilled	**25**	11	16	**78**	94
Net successful bitumen wells drilled	**24**	11	16	**77**	94
Success rate	**96%**	100%	100%	**99%**	100%

- Thermal in situ achieved record annual production in 2025, averaging 275,086 bbl/d, an increase of 2% from 2024 levels, reflecting the Company's capital efficient pad add and development program, partially offset by natural field declines.
  - Thermal in situ operating costs remain strong, averaging $11.09/bbl (US$7.93/bbl) in 2025, comparable to 2024 levels.
- 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.
  - The first Pike 1 pad was brought on production ahead of schedule in December 2025 which is tied into the Jackfish 3 facility. Current production rates from this pad of approximately 27,000 bbl/d are exceeding expectations, with a Steam to Oil Ratio ("SOR") of approximately 1.8x. A second Pike 1 pad is targeted to come on production in April 2026 and is targeted to keep production at the Jackfish 3 facility at full capacity.
  - 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 Steam Assisted Gravity Drainage ("SAGD") pad in Q2/26, which is targeted to come on production in 2027.

- As part of the Company's defined medium-term growth strategy, in 2026, front end engineering is progressing on both its 70,000 bbl/d Pike 2 growth project and 30,000 bbl/d Jackfish expansion project. In December 2025, Canadian Natural received regulatory approval for the Pike 2 SAGD project.
- 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 targeted 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			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs production (bbl/d)	**319,189**	309,873	255,729	**294,315**	238,277
Net crude oil wells drilled	**90**	78	84	**282**	214
Net successful crude oil wells drilled	**90**	78	84	**281**	213
Success rate	**100%**	100%	100%	**99%**	99%

- North America E&P liquids production, excluding thermal in situ, averaged 294,315 bbl/d in 2025, an increase of 24% or approximately 56,000 bbl/d from 2024 levels, reflecting opportunistic acquisitions and strong organic growth from heavy crude oil multilaterals, light crude oil and liquids-rich natural gas.
  - Primary heavy crude oil production averaged 87,888 bbl/d in 2025, an increase of 11% from 2024 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 land throughout our primary heavy crude oil assets.
    - Operating costs in the Company's primary heavy crude oil operations averaged $16.68/bbl (US$11.93/bbl) in 2025, a decrease of 8% from 2024 levels, primarily reflecting lower operating cost multilateral production.
  - Pelican Lake production averaged 42,470 bbl/d in 2025, a decrease of 5% from 2024 levels, reflecting the low natural field declines from this long life low decline asset.
    - Operating costs at Pelican Lake averaged $9.24/bbl (US$6.61/bbl) in 2025, comparable to 2024 levels.
  - North America light crude oil and NGLs production averaged 163,957 bbl/d in 2025, an increase of 43% or approximately 50,000 bbl/d from 2024 levels, primarily reflecting opportunistic acquisitions and strong drilling results.
    - Operating costs in the Company's North America light crude oil and NGLs operations averaged $12.39/bbl (US$8.87/bbl) in 2025, a decrease of 9% from 2024 levels, primarily reflecting higher production volumes.

North America Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Natural gas production (MMcf/d)	**2,657**	2,658	2,273	**2,538**	2,136
Net natural gas wells drilled	**20**	17	14	**78**	79
Net successful natural gas wells drilled	**20**	17	14	**78**	78
Success rate	**100%**	100%	100%	**100%**	99%

- Record North America natural gas production was achieved in 2025, averaging 2,538 MMcf/d, an increase of 19% from 2024 levels, primarily reflecting opportunistic acquisitions and strong drilling results in the Company's liquids-rich natural gas assets.
  - North America natural gas operating costs averaged $1.11/Mcf in 2025, a decrease of 7% from 2024 levels, primarily reflecting higher production volumes and cost efficiencies.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil production (bbl/d)	**9,966**	9,843	23,411	**11,672**	24,070
Natural gas production (MMcf/d)	**3**	10	10	**9**	11

- International E&P crude oil production volumes averaged 11,672 bbl/d in 2025, a decrease of 52% compared to 2024 levels. The decrease reflects temporary suspension of production at Baobab in Offshore Africa due to the planned refurbishment of its floating production storage and offloading ("FPSO") vessel which is expected to return to service in Q2/26, planned decommissioning activities in the North Sea and natural field declines.

Drilling Activity

	Year Ended			
	December 31, 2025		December 31, 2024	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil (1)	**368**	**358**	313	307
Natural gas	**99**	**78**	94	78
Dry	**2**	**2**	2	2
Subtotal	**469**	**438**	409	387
Stratigraphic test / service wells	**522**	**499**	474	407
Total	**991**	**937**	883	794
Success rate (excluding stratigraphic test / service wells)		**99%**		99%

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 438 net crude oil and natural gas wells in 2025, 51 more than in 2024.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Benchmark Commodity Prices					
WTI benchmark price (US$/bbl) [1]	**$ 59.13**	$ 64.95	$ 70.27	**$ 64.77**	$ 75.72
WCS heavy differential (discount) to WTI (US$/bbl) [1]	**$ (11.20)**	$ (10.36)	$ (12.55)	**$ (11.10)**	$ (14.73)
WCS heavy differential as a percentage of WTI (%) [1]	**19%**	16%	18%	**17%**	19%
Condensate benchmark price (US$/bbl)	**$ 57.01**	$ 63.12	$ 70.66	**$ 63.32**	$ 72.94
SCO price (US$/bbl) [1]	**$ 57.78**	$ 66.26	$ 71.13	**$ 64.42**	$ 75.09
SCO premium (discount) to WTI (US$/bbl) [1]	**$ (1.35)**	$ 1.31	$ 0.86	**$ (0.35)**	$ (0.63)
AECO benchmark price (C$/GJ)	**$ 2.22**	$ 0.94	$ 1.38	**$ 1.76**	$ 1.36
Realized Prices					
Exploration & Production liquids realized price (C$/bbl) [2][3][4][5]	**$ 64.42**	$ 72.57	$ 75.22	**$ 71.54**	$ 77.76
SCO realized price (C$/bbl) [1][3][4][5]	**$ 75.90**	$ 87.85	$ 95.08	**$ 86.41**	$ 98.03
Natural gas realized price (C$/Mcf) [4]	**$ 2.89**	$ 1.49	$ 2.02	**$ 2.51**	$ 1.86

(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.
- 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 68,139 bbl/d in 2025.
- 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 Energy, Inc. ("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.

2025 YEAR END RESERVES

Determination of Reserves

For the year ended December 31, 2025, the Company retained IQREs, Sproule International Limited and GLJ Ltd., to evaluate and review all of the Company’s proved and proved plus probable reserves. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company’s Board of Directors has met with and carried out independent due diligence procedures with the IQREs as to the Company’s reserves.

Additional reserves information is disclosed in the Company's Annual Information Form.

Summary of Company Gross Reserves

As of December 31, 2025
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Thermal Bitumen (MMbbl)	Mining Bitumen (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
Total Company									
Proved									
Developed Producing	121	130	188	684	835	7,043	5,861	229	10,207
Developed Non-Producing	28	6	—	42	—	—	272	13	135
Undeveloped	160	92	55	2,603	14	91	11,873	575	5,568
Total Proved	309	228	243	3,330	849	7,134	18,006	817	15,910
Probable	118	105	107	1,845	46	554	9,969	404	4,840
Total Proved plus Probable	427	333	349	5,175	895	7,688	27,974	1,221	20,750

Notes to Reserves:

1. Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
2. Information in the reserves data tables may not add due to rounding. BOE values and oil and natural gas metrics may not calculate exactly due to rounding.
3. Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserves estimates are the 3-Consultant-Average of price forecasts developed by Sproule International Limited, GLJ Ltd. and McDaniel & Associates Consultants Ltd., dated December 31, 2025:

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

All prices increase at a rate of 2% per year after 2030.

A US$/C$ foreign exchange rate of 0.7277 was used for 2026, 0.7367 for 2027, and 0.7400 for 2028 and thereafter in the year end 2025 evaluation.

4. A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

5. Oil and natural gas metrics included herein are commonly used in the crude oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural’s performance over time. However, such measures are not reliable indicators of Canadian Natural’s future performance and future performance may vary.
6. Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.
7. Reserves replacement or Production replacement ratio is the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.
8. Reserves Life Index ("RLI") is based on the amount for the relevant reserves category divided by the 2026 proved developed producing production forecast prepared by the IQREs.
9. Finding, Development and Acquisition ("FD&A") costs including changes in Future Development Costs ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2025 and net changes in FDC from December 31, 2024 to December 31, 2025 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment, decommissioning and reclamation costs.
10. Abandonment, decommissioning and reclamation ("ADR") costs included in the calculation of the Future Net Revenue ("FNR") consist of both the Company's Asset Retirement Obligation ("ARO") for North America and Offshore Africa, before inflation and discounting, for development existing as at December 31, 2025 and forecast estimates of ADR costs attributable to future development activity.

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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 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 and year ended December 31, 2025 dated March 4, 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.

Up to October 2024, before the announcement of the Chevron acquisition, the Company was targeting to allocate 100% of its free cash flow in 2024 to shareholder returns.

In October 2024, with the announcement of the Chevron acquisition, the Board of Directors adjusted the allocation of free cash flow as follows:

- 60% of free cash flow to shareholder returns and 40% to the balance sheet until net debt reaches $15 billion.
- When net debt is between $12 billion and $15 billion, free cash flow allocation will be 75% to shareholder returns and 25% to the balance sheet.
- When net debt is at or below $12 billion, free cash flow allocation will be 100% to shareholder returns.

The Company's free cash flow for the year ended December 31, 2025 and comparable period is shown below:

	Year Ended	
($ millions)	Dec 31 2025	Dec 31 2024
Adjusted funds flow (1)	$ 15,460	$ 14,859
Less: Dividends on common shares	4,871	4,429
Net capital expenditures (2)	6,579	5,286
Abandonment expenditures	771	646
Free cash flow	$ 3,239	$ 4,498

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, which are provided in the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A for the three months and year ended December 31, 2025 dated March 4, 2026.

(2) Non-GAAP Financial Measure. In 2024, for the purpose of the free cash flow calculated above, net capital expenditures of $5,286 million excludes net acquisitions of $9,145 million. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A for the three months and year ended December 31, 2025 dated March 4, 2026.

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.

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)	Dec 31 2025	Sep 30 2025	Dec 31 2024
Long-term debt	**$ 16,617**	$ 17,268	$ 18,819
Less: cash and cash equivalents	**673**	113	131
Long-term debt, net	**$ 15,944**	$ 17,155	$ 18,688

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 is a forward-looking non-GAAP financial measure and is based on net capital expenditures (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. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A for more details on net capital expenditures.

Capital expenditures reflect forecasted net capital expenditures, before 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 on 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.

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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, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, forecast and anticipated abandonment expenditures, income tax expenses, and other targets provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, including the strength of the Company's balance sheet, the sources and adequacy of the Company's liquidity, and the flexibility of the Company's capital structure, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to: the Company's assets at Horizon 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, Ukraine and Venezuela, 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 the Company's bitumen products; availability and cost of financing; the Company's success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets, including the acquisition of the remaining interest in the AOSP mines and other acquisitions that occurred in 2025; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; changes to future abandonment and decommissioning costs; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety, competition, environmental laws and regulations, and the impact of climate change initiatives on capital expenditures and production expenses); interpretations of applicable tax and competition laws and regulations; asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short-, medium-, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; the impact of legal proceedings to which the Company is party; and other circumstances affecting revenues and expenses.

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

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

Special Note Regarding Non-GAAP and Other Financial Measures

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

Special Note Regarding Common Share Split and Comparative Figures

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

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

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

Special Note Regarding Currency, Financial Information 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 and year ended December 31, 2025, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2024. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three months and year ended December 31, 2025 and this MD&A have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards").

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

The following discussion and analysis refers primarily to the Company's financial results for the three months and year ended December 31, 2025 in relation to the comparable periods in 2024 and the third 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, 2024, 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 March 4, 2026.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)		Three Months Ended			Year Ended	
		Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Product sales [1]		**$ 10,710**	$ 11,070	$ 11,064	**$ 44,167**	$ 41,509
Crude oil and NGLs		**$ 9,666**	$ 10,468	$ 10,381	**$ 40,740**	$ 39,084
Natural gas		**$ 735**	$ 399	$ 451	**$ 2,450**	$ 1,568
Net earnings		**$ 5,303**	$ 600	$ 1,138	**$ 10,820**	$ 6,106
Per common share	– basic	**$ 2.55**	$ 0.29	$ 0.54	**$ 5.17**	$ 2.87
	– diluted	**$ 2.54**	$ 0.29	$ 0.54	**$ 5.16**	$ 2.85
Adjusted net earnings from operations [2]		**$ 1,711**	$ 1,801	$ 1,977	**$ 7,444**	$ 7,414
Per common share	– basic [3]	**$ 0.82**	$ 0.86	$ 0.94	**$ 3.56**	$ 3.49
	– diluted [3]	**$ 0.82**	$ 0.86	$ 0.93	**$ 3.55**	$ 3.46
Cash flows from operating activities		**$ 3,768**	$ 3,940	$ 3,432	**$ 15,106**	$ 13,386
Adjusted funds flow [2]		**$ 3,748**	$ 3,920	$ 4,186	**$ 15,460**	$ 14,859
Per common share	– basic [3]	**$ 1.80**	$ 1.88	$ 1.99	**$ 7.39**	$ 6.99
	– diluted [3]	**$ 1.79**	$ 1.87	$ 1.97	**$ 7.37**	$ 6.94
Cash flows used in investing activities		**$ 1,200**	$ 2,234	$ 10,414	**$ 6,687**	$ 14,095
Net capital expenditures [2]		**$ 1,237**	$ 2,124	$ 10,348	**$ 6,579**	$ 14,431
Abandonment expenditures		**$ 201**	$ 189	$ 151	**$ 771**	$ 646

(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 year ended December 31, 2025 were $10,820 million compared with $6,106 million for the year ended December 31, 2024. Net earnings for the year ended December 31, 2025 included non-operating income, net of tax, of $3,376 million compared with non-operating losses of $1,308 million for the year ended December 31, 2024 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on financing activities, the gain from investment, the gain on acquisitions, disposition, and remeasurement, and recoverability charges related to the North Sea and Offshore Africa. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2025 were $7,444 million compared with $7,414 million for the year ended December 31, 2024.

Net earnings for the fourth quarter of 2025 were $5,303 million compared with $1,138 million for the fourth quarter of 2024 and $600 million for the third quarter of 2025. Net earnings for the fourth quarter of 2025 included non-operating income, net of tax, of $3,592 million compared with non-operating losses of $839 million for the fourth quarter of 2024 and non-operating losses of $1,201 million for the third 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, the gain on acquisitions, disposition, and remeasurement, and recoverability charges related to the North Sea and Offshore Africa. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2025 were $1,711 million compared with $1,977 million for the fourth quarter of 2024 and $1,801 million for the third quarter of 2025.

The movements in net earnings and adjusted net earnings from operations for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected:

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

partially offset by:

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

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

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

partially offset by:

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

The impacts of depletion, depreciation and amortization, share-based compensation, risk management activities, foreign exchange (gain) loss, the gain on acquisitions, disposition, and remeasurement, the gain from investment, and recoverability charges related to the North Sea and Offshore Africa 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. The AOSP asset swap is discussed below, and the recoverability charges related to the North Sea and Offshore Africa are discussed in detail in the 'Adjusted Depletion, Depreciation and Amortization – Exploration and Production' section of this MD&A.

AOSP Asset Swap Transaction

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

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

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the year ended December 31, 2025 were $15,106 million compared with $13,386 million for the year ended December 31, 2024. Cash flows from operating activities for the fourth quarter of 2025 were $3,768 million compared with $3,432 million for the fourth quarter of 2024 and $3,940 million for the third 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 year ended December 31, 2025 was $15,460 million compared with $14,859 million for the year ended December 31, 2024. Adjusted funds flow for the fourth quarter of 2025 was $3,748 million compared with $4,186 million for the fourth quarter of 2024 and $3,920 million for the third 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") and corporate tax recoveries, and prepaid cost of service tolls.

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

Production Volumes

Record crude oil and NGLs production before royalties for the fourth quarter of 2025 of 1,215,364 bbl/d increased 12% from 1,090,002 bbl/d for the fourth quarter of 2024 and increased 3% from 1,175,604 bbl/d for the third quarter of 2025. Natural gas production before royalties for the fourth quarter of 2025 of 2,660 MMcf/d increased 17% from 2,283 MMcf/d for the fourth quarter of 2024 and was comparable with 2,668 MMcf/d for the third quarter of 2025. Total production before royalties for the fourth quarter of 2025 of 1,658,681 BOE/d increased 13% from 1,470,428 BOE/d for the fourth quarter of 2024 and was comparable with 1,620,261 BOE/d for the third 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 $64.42 per bbl for the fourth quarter of 2025, a decrease of 14% from $75.22 per bbl for the fourth quarter of 2024 and a decrease of 11% from $72.57 per bbl for the third quarter of 2025. The realized natural gas price increased 43% to average $2.89 per Mcf for the fourth quarter of 2025 from $2.02 per Mcf for the fourth quarter of 2024 and increased 94% from $1.49 per Mcf for the third quarter of 2025. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price decreased 20% to average $75.90 per bbl for the fourth quarter of 2025 from $95.08 per bbl for the fourth quarter of 2024 and decreased 14% from $87.85 per bbl for the third 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 the 'Realized Product Prices, Royalties and Transportation – Oil Sands Mining and Upgrading' sections of this MD&A.

Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense[(1)] averaged $14.35 per bbl for the fourth quarter of 2025, an increase of 9% from $13.15 per bbl for the fourth quarter of 2024 and $13.18 per bbl for the third quarter of 2025. Natural gas production expense[(1)] averaged $1.10 per Mcf for the fourth quarter of 2025, comparable with $1.12 per Mcf for the fourth quarter of 2024 and a decrease of 5% from $1.16 per Mcf for the third quarter of 2025. In the Oil Sands Mining and Upgrading segment, production expense[(1)] averaged $21.84 per bbl for the fourth quarter of 2025, an increase of 4% from $20.97 per bbl for the fourth quarter of 2024 and an increase of 3% from $21.29 per bbl for the third quarter of 2025. Crude oil and NGLs and natural gas production expense is discussed in detail in the 'Production Expense – Exploration and Production' and the 'Production Expense – Oil Sands Mining and Upgrading' sections of this MD&A.

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

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

(1) Further details related to product sales for the three months ended December 31, 2025 and 2024 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, Ukraine and Venezuela, and the impacts of ongoing tariff and trade uncertainty) on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the start-up of the Trans Mountain Expansion ("TMX") pipeline in the second quarter of 2024, 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, and the AOSP asset swap in the fourth quarter of 2025), wildfires, and maintenance activities in the North America Exploration and Production segment. Sales volumes in the International segments also reflected fluctuations due to the timing of liftings, planned abandonment activities in the North Sea, and temporary suspension of production at Baobab in Offshore Africa for planned 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, and the acquisition of assets in the Grande Prairie area in the third quarter of 2025), natural field declines, the impact of seasonal conditions, and wildfires in the North America Exploration and Production segment.
- **Production expense** – Fluctuations primarily due to the impacts of the demand and cost for services, fluctuations in product mix and production volumes, seasonal conditions, carbon tax, fluctuating energy costs, inflationary cost pressures, cost optimizations across all segments, turnarounds in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.

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

BUSINESS ENVIRONMENT

Global crude oil benchmark pricing declined through the fourth quarter of 2025 as increasing global supply outpaced relatively modest demand growth, which remained subdued amid ongoing tariff and trade uncertainty. Late in the fourth quarter of 2025, escalating geopolitical tensions contributed to heightened concerns regarding potential crude oil supply disruptions entering into 2026. Natural gas benchmark pricing increased during the fourth quarter of 2025, driven by seasonal demand factors and continued strength in LNG export activity out of the US Gulf Coast. In Canada, AECO benchmark pricing improved due to robust export volumes out of the Western Canadian Sedimentary Basin ("WCSB"). The ongoing ramp-up of LNG Canada is expected to further increase LNG demand and support AECO pricing in 2026.

In the first quarter of 2025, the US government announced tariffs on certain Canadian goods. While these actions have contributed to market volatility, including commodity price and foreign currency volatility, these tariffs have not had a material impact on the Company's financial results as of the date of this MD&A. The duration of these trade actions remains uncertain, and broader changes to US economic policy may have a material effect on the Company's business, financial conditions, or results in future periods. The Company will continue to monitor and assess the implications of any current or emerging US economic policies.

Benchmark Commodity Prices

	Three Months Ended			Year Ended	
(Average for the period)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
WTI benchmark price (US$/bbl)	**$ 59.13**	$ 64.95	$ 70.27	**$ 64.77**	$ 75.72
Dated Brent benchmark price (US$/bbl)	**$ 63.69**	$ 69.08	$ 74.69	**$ 69.02**	$ 80.75
WCS Heavy Differential from WTI (US$/bbl)	**$ 11.20**	$ 10.36	$ 12.55	**$ 11.10**	$ 14.73
SCO price (US$/bbl)	**$ 57.78**	$ 66.26	$ 71.13	**$ 64.42**	$ 75.09
Condensate benchmark price (US$/bbl)	**$ 57.01**	$ 63.12	$ 70.66	**$ 63.32**	$ 72.94
NYMEX benchmark price (US$/MMBtu)	**$ 3.55**	$ 3.07	$ 2.79	**$ 3.43**	$ 2.27
AECO benchmark price (C$/GJ)	**$ 2.22**	$ 0.94	$ 1.38	**$ 1.76**	$ 1.36
US/Canadian dollar average exchange rate (US$)	**$ 0.7170**	$ 0.7262	$ 0.7151	**$ 0.7155**	$ 0.7300

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

Crude oil sales contracts in North America are typically based on WTI benchmark pricing. WTI averaged US$64.77 per bbl for the year ended December 31, 2025, a decrease of 14% from US$75.72 per bbl for the year ended December 31, 2024. WTI averaged US$59.13 per bbl for the fourth quarter of 2025, a decrease of 16% from US$70.27 per bbl for the fourth quarter of 2024 and a decrease of 9% from US$64.95 per bbl for the third 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$69.02 per bbl for the year ended December 31, 2025, a decrease of 15% from US$80.75 per bbl for the year ended December 31, 2024. Brent averaged US$63.69 per bbl for the fourth quarter of 2025, a decrease of 15% from US$74.69 per bbl for the fourth quarter of 2024 and a decrease of 8% from US$69.08 per bbl for the third quarter of 2025.

The decrease in WTI and Brent benchmark pricing for the three months and year ended December 31, 2025 from the comparable periods primarily reflected increased global supply and inventory builds driven by near-record production from non-OPEC+ producers and higher OPEC+ output. Supply gains exceeded global demand growth, which remained muted amid ongoing tariff and trade uncertainty.

The WCS Heavy Differential averaged US$11.10 per bbl for the year ended December 31, 2025, compared with US$14.73 per bbl for the year ended December 31, 2024. The WCS Heavy Differential averaged US$11.20 per bbl for the fourth quarter of 2025, compared with US$12.55 per bbl for the fourth quarter of 2024 and US$10.36 per bbl for the third quarter of 2025. The narrowing of the WCS Heavy Differential for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected full year takeaway capacity on the TMX pipeline and strong US Gulf Coast heavy oil pricing. The widening of the WCS Heavy Differential for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected seasonal demand factors and strong production, together with pipeline apportionment in the WCSB.

The SCO price averaged US$64.42 per bbl for the year ended December 31, 2025, a decrease of 14% from US$75.09 per bbl for the year ended December 31, 2024. The SCO price averaged US$57.78 per bbl for the fourth quarter of 2025, a decrease of 19% from US$71.13 per bbl for the fourth quarter of 2024 and a decrease of 13% from US$66.26 per bbl for the third quarter of 2025. The decrease in SCO pricing for the three months and year ended December 31, 2025 from the comparable periods primarily reflected weaker WTI benchmark pricing.

NYMEX benchmark pricing averaged US$3.43 per MMBtu for the year ended December 31, 2025, an increase of 51% from US$2.27 per MMBtu for the year ended December 31, 2024. NYMEX benchmark pricing averaged US$3.55 per MMBtu for the fourth quarter of 2025, an increase of 27% from US$2.79 per MMBtu for the fourth quarter of 2024 and an increase of 16% from US$3.07 per MMBtu for the third quarter of 2025. The increase in NYMEX natural gas pricing for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected lower US inventory levels in the first half of 2025, combined with record LNG exports out of the US Gulf Coast. The increase in NYMEX natural gas pricing for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected seasonal demand factors and strong LNG exports out of the US Gulf Coast.

AECO benchmark pricing averaged $1.76 per GJ for the year ended December 31, 2025, an increase of 29% from $1.36 per GJ for the year ended December 31, 2024. AECO benchmark pricing averaged $2.22 per GJ for the fourth quarter of 2025, an increase of 61% from $1.38 per GJ for the fourth quarter of 2024 and an increase of 136% from $0.94 per GJ for the third quarter of 2025. The increase in AECO natural gas pricing for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected higher NYMEX benchmark pricing and increased exports out of the WCSB. The increase in AECO natural gas pricing for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected improved seasonal demand factors and stronger WCSB exports following third quarter pipeline maintenance.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**585,497**	584,625	531,960	**569,401**	509,288
North America – Oil Sands Mining and Upgrading [(1)]	**619,901**	581,136	534,631	**565,102**	472,245
International – Exploration and Production					
North Sea	**7,618**	7,045	11,467	**8,468**	11,536
Offshore Africa	**2,348**	2,798	11,944	**3,204**	12,534
Total International [(2)]	**9,966**	9,843	23,411	**11,672**	24,070
Total Crude oil and NGLs	**1,215,364**	1,175,604	1,090,002	**1,146,175**	1,005,603
Natural gas (MMcf/d) [(3)]					
North America	**2,657**	2,658	2,273	**2,538**	2,136
International					
North Sea	**3**	2	4	**3**	2
Offshore Africa	**—**	8	6	**6**	9
Total International	**3**	10	10	**9**	11
Total Natural gas	**2,660**	2,668	2,283	**2,547**	2,147
Total Barrels of oil equivalent (BOE/d)	**1,658,681**	1,620,261	1,470,428	**1,570,757**	1,363,496
Product mix					
Light and medium crude oil and NGLs	**12%**	12%	10%	**11%**	10%
Pelican Lake heavy crude oil	**3%**	3%	3%	**3%**	3%
Primary heavy crude oil	**5%**	5%	6%	**6%**	6%
Thermal bitumen	**16%**	17%	19%	**17%**	20%
Synthetic crude oil [(1)]	**37%**	36%	36%	**36%**	35%
Natural gas	**27%**	27%	26%	**27%**	26%
Percentage of product sales [(1) (4) (5)]					
Crude oil and NGLs	**92%**	96%	96%	**94%**	96%
Natural gas	**8%**	4%	4%	**6%**	4%

(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			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**499,585**	479,660	425,682	**476,850**	408,237
North America – Oil Sands Mining and Upgrading (1)	**518,709**	473,188	432,701	**467,415**	386,171
International – Exploration and Production					
North Sea	**7,610**	7,017	11,441	**8,451**	11,509
Offshore Africa	**2,240**	2,669	11,364	**3,061**	11,918
Total International	**9,850**	9,686	22,805	**11,512**	23,427
Total Crude oil and NGLs	**1,028,144**	962,534	881,188	**955,777**	817,835
Natural gas (MMcf/d)					
North America	**2,570**	2,615	2,223	**2,466**	2,091
International					
North Sea	**3**	2	4	**3**	2
Offshore Africa	**—**	8	6	**6**	9
Total International	**3**	10	10	**9**	11
Total Natural gas	**2,573**	2,625	2,233	**2,475**	2,102
Total Barrels of oil equivalent (BOE/d)	**1,456,944**	1,399,968	1,253,347	**1,368,198**	1,168,209

(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.

Record crude oil and NGLs production before royalties for the year ended December 31, 2025 averaged 1,146,175 bbl/d, an increase of 14% from 1,005,603 bbl/d for the year ended December 31, 2024. Record crude oil and NGLs production before royalties for the fourth quarter of 2025 averaged 1,215,364 bbl/d, an increase of 12% from 1,090,002 bbl/d for the fourth quarter of 2024 and an increase of 3% from 1,175,604 bbl/d for the third quarter of 2025. The increase in crude oil and NGLs production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, strong utilization in the Oil Sands Mining and Upgrading segment, and strong drilling results in the North America Exploration and Production segment. The increase for the fourth quarter of 2025 from the fourth quarter of 2024 also reflected the completion of the AOSP asset swap in November 2025. The increase in crude oil and NGLs production before royalties for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected the completion of the AOSP asset swap in November 2025, combined with strong utilization in the Oil Sands Mining and Upgrading segment.

Annual crude oil and NGLs production before royalties for 2025 was within the Company's previously issued production target of 1,137,000 bbl/d and 1,151,000 bbl/d. Annual crude oil and NGLs production before royalties for 2026 is now targeted to average between 1,188,000 bbl/d and 1,229,000 bbl/d. Production targets constitute forward-looking statements. Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

Record natural gas production before royalties for the year ended December 31, 2025 averaged 2,547 MMcf/d, an increase of 19% from 2,147 MMcf/d for the year ended December 31, 2024. Natural gas production before royalties for the fourth quarter of 2025 averaged 2,660 MMcf/d, an increase of 17% from 2,283 MMcf/d for the fourth quarter of 2024 and comparable with 2,668 MMcf/d for the third quarter of 2025. The increase in natural gas production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, combined with strong drilling results in the Company's liquids-rich natural gas assets.

Annual natural gas production before royalties for 2025 was within the Company's previously issued production target of 2,535 MMcf/d and 2,575 MMcf/d. Annual natural gas production before royalties for 2026 is now targeted to average between 2,560 MMcf/d and 2,615 MMcf/d. Production targets constitute forward-looking statements. Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

North America – Exploration and Production

Record North America crude oil and NGLs production before royalties for the year ended December 31, 2025 averaged 569,401 bbl/d, an increase of 12% from 509,288 bbl/d for the year ended December 31, 2024. North America crude oil and NGLs production before royalties for the fourth quarter of 2025 of 585,497 bbl/d increased 10% from 531,960 bbl/d for the fourth quarter of 2024 and was comparable with 584,625 bbl/d for the third quarter of 2025. The increase in North America crude oil and NGLs production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, combined with strong drilling results.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 266,308 bbl/d for the fourth quarter of 2025, a decrease of 4% from 276,231 bbl/d for the fourth quarter of 2024 and comparable with 274,752 bbl/d for the third quarter of 2025. The decrease in thermal in situ production for the fourth quarter of 2025 from the fourth quarter of 2024 primarily reflected the cyclical nature of Primrose and natural field declines, partially offset by thermal pad additions.

Pelican Lake heavy crude oil production before royalties for the fourth quarter of 2025 averaged 41,577 bbl/d, a decrease of 6% from 44,035 bbl/d for the fourth quarter of 2024 reflecting Pelican Lake's long life low decline production, and comparable with 42,070 bbl/d for the third quarter of 2025.

Record North America natural gas production before royalties for the year ended December 31, 2025 averaged 2,538 MMcf/d, an increase of 19% from 2,136 MMcf/d for the year ended December 31, 2024. Natural gas production before royalties averaged 2,657 MMcf/d for the fourth quarter of 2025, an increase of 17% from 2,273 MMcf/d for the fourth quarter of 2024 and comparable with 2,658 MMcf/d for the third quarter of 2025. The increase in natural gas production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, combined with strong drilling results in the Company's liquids-rich natural gas assets.

North America – Oil Sands Mining and Upgrading

Record SCO production before royalties for the year ended December 31, 2025 averaged 565,102 bbl/d, an increase of 20% from 472,245 bbl/d for the year ended December 31, 2024. Record SCO production before royalties for the fourth quarter of 2025 averaged 619,901 bbl/d, an increase of 16% from 534,631 bbl/d for the fourth quarter of 2024 and an increase of 7% from 581,136 bbl/d for the third quarter of 2025. The increase in SCO production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the acquisition completed in December 2024, combined with strong utilization. The increase in SCO production for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected the completion of the AOSP asset swap in November 2025, combined with strong utilization.

International – Exploration and Production

International crude oil and NGLs production before royalties for the year ended December 31, 2025 averaged 11,672 bbl/d, a decrease of 52% from 24,070 bbl/d for the year ended December 31, 2024. International crude oil and NGLs production before royalties for the fourth quarter of 2025 averaged 9,966 bbl/d, a decrease of 57% from 23,411 bbl/d for the fourth quarter of 2024 and comparable with 9,843 bbl/d for the third quarter of 2025. The decrease in International crude oil and NGLs production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the temporary suspension of production at Baobab in Offshore Africa due to planned maintenance on its FPSO, which is expected to return to service in the second quarter of 2026, planned North Sea abandonments conducted as part of the previously announced decommissioning plans, and natural field declines.

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs ($/bbl) [1]					
Realized price [2]	**$ 64.42**	$ 72.57	$ 75.22	**$ 71.54**	$ 77.76
Transportation [3]	**7.14**	6.93	6.08	**7.02**	5.50
Realized price, net of transportation [2]	**57.28**	65.64	69.14	**64.52**	72.26
Royalties [4]	**9.46**	13.10	14.77	**11.53**	14.85
Production expense [5]	**14.35**	13.18	13.15	**14.33**	14.72
Netback [2]	**$ 33.47**	$ 39.36	$ 41.22	**$ 38.66**	$ 42.69
Natural gas ($/Mcf) [1]					
Realized price [6]	**$ 2.89**	$ 1.49	$ 2.02	**$ 2.51**	$ 1.86
Transportation [3]	**0.56**	0.57	0.59	**0.59**	0.62
Realized price, net of transportation	**2.33**	0.92	1.43	**1.92**	1.24
Royalties [4]	**0.09**	0.02	0.04	**0.08**	0.05
Production expense [5]	**1.10**	1.16	1.12	**1.14**	1.22
Netback [7]	**$ 1.14**	$ (0.26)	$ 0.27	**$ 0.70**	$ (0.03)
Barrels of oil equivalent ($/BOE) [1]					
Realized price [2]	**$ 44.85**	$ 45.31	$ 49.54	**$ 47.98**	$ 50.82
Transportation [3]	**5.56**	5.38	5.06	**5.54**	4.78
Realized price, net of transportation [2]	**39.29**	39.93	44.48	**42.44**	46.04
Royalties [4]	**5.73**	7.53	8.85	**6.90**	8.96
Production expense [5]	**11.08**	10.50	10.53	**11.18**	11.73
Netback [2]	**$ 22.48**	$ 21.90	$ 25.10	**$ 24.36**	$ 25.35

(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			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs ($/bbl) (1)					
North America (2)	**$ 63.83**	$ 72.35	$ 74.46	**$ 70.90**	$ 76.37
International average (3)	**$ 87.45**	$ 94.08	$ 96.36	**$ 98.07**	$ 108.80
North Sea (3)	**$ 89.02**	$ 90.19	$ 103.80	**$ 97.26**	$ 111.53
Offshore Africa (3)	**$ 83.53**	$ 99.90	$ 86.93	**$ 99.71**	$ 106.00
Crude oil and NGLs average (2)	**$ 64.42**	$ 72.57	$ 75.22	**$ 71.54**	$ 77.76
Natural gas ($/Mcf) (1) (3)					
North America	**$ 2.89**	$ 1.45	$ 1.98	**$ 2.47**	$ 1.81
International average	**$ 8.87**	$ 11.22	$ 11.28	**$ 12.45**	$ 12.01
North Sea	**$ 8.87**	$ 8.57	$ 8.87	**$ 11.77**	$ 9.93
Offshore Africa	**$ —**	$ 11.87	$ 12.62	**$ 12.77**	$ 12.46
Natural gas average	**$ 2.89**	$ 1.49	$ 2.02	**$ 2.51**	$ 1.86
Average ($/BOE) (1) (2)	**$ 44.85**	$ 45.31	$ 49.54	**$ 47.98**	$ 50.82

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

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

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

North America

North America realized crude oil and NGLs prices decreased 7% to average $70.90 per bbl for the year ended December 31, 2025 from $76.37 per bbl for the year ended December 31, 2024. North America realized crude oil and NGLs prices averaged $63.83 per bbl for the fourth quarter of 2025, a decrease of 14% from $74.46 per bbl for the fourth quarter of 2024 and a decrease of 12% from $72.35 per bbl for the third quarter of 2025. The decrease in North America realized crude oil and NGLs prices per bbl for the year ended December 31, 2025 from the year ended December 31, 2024 primarily reflected lower WTI benchmark pricing, partially offset by a narrowing of the WCS Heavy Differential. The decrease in North America realized crude oil and NGLs prices per bbl for the fourth quarter of 2025 from the comparable periods primarily reflected lower 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 fourth quarter of 2025 contributed approximately 230,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 36% to average $2.47 per Mcf for the year ended December 31, 2025 from $1.81 per Mcf for the year ended December 31, 2024. North America realized natural gas prices increased 46% to average $2.89 per Mcf for the fourth quarter of 2025 from $1.98 per Mcf for the fourth quarter of 2024 and increased 99% from $1.45 per Mcf for the third quarter of 2025. The increase in North America realized natural gas prices per Mcf for the three months and year ended December 31, 2025 from the comparable periods primarily reflected higher AECO benchmark and export pricing.

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

	Three Months Ended		
(Quarterly average)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024
Wellhead Price (1)			
Light and medium crude oil and NGLs ($/bbl)	**$ 58.26**	$ 66.29	$ 68.63
Pelican Lake heavy crude oil ($/bbl)	**$ 66.75**	$ 75.94	$ 79.88
Primary heavy crude oil ($/bbl)	**$ 65.69**	$ 75.55	$ 78.34
Thermal bitumen ($/bbl)	**$ 66.61**	$ 74.83	$ 75.11
Natural gas ($/Mcf)	**$ 2.89**	$ 1.45	$ 1.98

(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 10% to average $98.07 per bbl for the year ended December 31, 2025 from $108.80 per bbl for the year ended December 31, 2024. International realized crude oil and NGLs prices decreased 9% to average $87.45 per bbl for the fourth quarter of 2025 from $96.36 per bbl for the fourth quarter of 2024 and decreased 7% from $94.08 per bbl for the third 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			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 9.67**	$ 13.21	$ 15.22	**$ 11.77**	$ 15.40
International average	**$ 1.16**	$ 2.05	$ 1.99	**$ 1.56**	$ 2.75
North Sea	**$ 0.09**	$ 0.35	$ 0.23	**$ 0.15**	$ 0.26
Offshore Africa	**$ 3.84**	$ 4.60	$ 4.22	**$ 4.41**	$ 5.30
Crude oil and NGLs average	**$ 9.46**	$ 13.10	$ 14.77	**$ 11.53**	$ 14.85
Natural gas ($/Mcf) [1]					
North America	**$ 0.09**	$ 0.02	$ 0.04	**$ 0.08**	$ 0.04
Offshore Africa	**$ —**	$ 0.55	$ 0.58	**$ 0.59**	$ 0.57
Natural gas average	**$ 0.09**	$ 0.02	$ 0.04	**$ 0.08**	$ 0.05
Average ($/BOE) [1]	**$ 5.73**	$ 7.53	$ 8.85	**$ 6.90**	$ 8.96

(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 three months and year ended December 31, 2025 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 17% of product sales for the year ended December 31, 2025 compared with 20% of product sales for the year ended December 31, 2024. Crude oil and NGLs royalty rates averaged approximately 15% of product sales for the fourth quarter of 2025 compared with 20% for the fourth quarter of 2024 and 18% for the third quarter of 2025. The decrease in royalty rates for the three months and year ended December 31, 2025 from the comparable periods primarily reflected lower benchmark pricing and the impact of sliding scale royalty rates.

Natural gas royalty rates averaged approximately 3% of product sales for the year ended December 31, 2025 compared with 2% of product sales for the year ended December 31, 2024. Natural gas royalty rates averaged approximately 3% of product sales for the fourth quarter of 2025 compared with 2% for the fourth quarter of 2024 and the third quarter of 2025. The increase in royalty rates for the three months and year ended December 31, 2025 from the comparable periods primarily reflected higher prevailing benchmark pricing.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 4% for the year ended December 31, 2025 compared with 5% of product sales for the year ended December 31, 2024. Royalty rates as a percentage of product sales averaged approximately 5% for the fourth quarter of 2025 compared with 5% of product sales for the fourth quarter of 2024 and the third 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			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 12.24**	$ 11.97	$ 10.83	**$ 12.19**	$ 12.55
International average	**$ 96.90**	$ 134.12	$ 77.66	**$ 103.48**	$ 62.99
North Sea	**$ 115.45**	$ 188.98	$ 118.91	**$ 136.47**	$ 103.28
Offshore Africa	**$ 50.50**	$ 52.17	$ 25.34	**$ 36.73**	$ 21.77
Crude oil and NGLs average	**$ 14.35**	$ 13.18	$ 13.15	**$ 14.33**	$ 14.72
Natural gas ($/Mcf) [1]					
North America	**$ 1.09**	$ 1.14	$ 1.09	**$ 1.11**	$ 1.19
International average	**$ 11.69**	$ 8.18	$ 7.81	**$ 9.23**	$ 6.51
North Sea	**$ 11.69**	$ 15.64	$ 9.38	**$ 12.18**	$ 8.95
Offshore Africa	**$ —**	$ 6.32	$ 6.94	**$ 7.80**	$ 5.98
Natural gas average	**$ 1.10**	$ 1.16	$ 1.12	**$ 1.14**	$ 1.22
Average ($/BOE) [1]	**$ 11.08**	$ 10.50	$ 10.53	**$ 11.18**	$ 11.73

(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 year ended December 31, 2025 averaged $12.19 per bbl, comparable with $12.55 per bbl for the year ended December 31, 2024. North America crude oil and NGLs production expense for the fourth quarter of 2025 of $12.24 per bbl increased 13% from $10.83 per bbl for the fourth quarter of 2024 and was comparable with $11.97 per bbl for the third quarter of 2025. The increase in crude oil and NGLs production expense per bbl for the fourth quarter of 2025 from the fourth quarter of 2024 primarily reflected higher fuel costs.

North America natural gas production expense for the year ended December 31, 2025 averaged $1.11 per Mcf, a decrease of 7% from $1.19 per Mcf for the year ended December 31, 2024. North America natural gas production expense for the fourth quarter of 2025 of $1.09 per Mcf was comparable with $1.09 per Mcf for the fourth quarter of 2024 and decreased 4% from $1.14 per Mcf for the third quarter of 2025. The decrease in natural gas production expense per Mcf for the year ended December 31, 2025 from the year ended December 31, 2024 primarily reflected higher production volumes. The decrease in natural gas production expense per Mcf for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected lower service costs.

International

International crude oil and NGLs production expense for the year ended December 31, 2025 averaged $103.48 per bbl, an increase of 64% from $62.99 per bbl for the year ended December 31, 2024. International crude oil and NGLs production expense for the fourth quarter of 2025 of $96.90 per bbl increased 25% from $77.66 per bbl for the fourth quarter of 2024 and decreased 28% from $134.12 per bbl for the third quarter of 2025. The increase in crude oil and NGLs production expense per bbl for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected activities at Ninian in the pre-cessation period, the timing of liftings from various fields that have different cost structures, and the impact of foreign exchange. The decrease in crude oil and NGLs production expense per bbl for the fourth quarter of 2025 from the third 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

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
North America	**$ 1,217**	$ 1,188	$ 1,010	**$ 4,582**	$ 3,831
North Sea	**215**	1,285	221	**1,573**	279
Offshore Africa	**340**	20	46	**432**	297
Depletion, depreciation and amortization	**$ 1,772**	$ 2,493	$ 1,277	**$ 6,587**	$ 4,407
Less: Recoverability charges (1)	**519**	1,258	160	**1,777**	222
Adjusted depletion, depreciation and amortization (2)	**$ 1,253**	$ 1,235	$ 1,117	**$ 4,810**	$ 4,185
$/BOE (3)	**$ 12.98**	$ 13.08	$ 13.01	**$ 13.07**	$ 12.92

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

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

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

Adjusted depletion, depreciation and amortization expense for the year ended December 31, 2025 averaged $13.07 per BOE, comparable with $12.92 per BOE for the year ended December 31, 2024. Adjusted depletion, depreciation and amortization expense for the fourth quarter of 2025 averaged $12.98 per BOE, comparable with $13.01 per BOE for the fourth quarter of 2024 and $13.08 per BOE for the third quarter of 2025.

International Matters – North Sea and Offshore Africa

Pre-tax recoverability charges of $1,777 million in 2025 reflect the acceleration of the Company's abandonment and decommissioning activities and revisions to cost estimates in the North Sea, together with strategic decisions to not pursue an extension of its Production Sharing Contract ("PSC") for the Espoir Field, Block CI-26, in Offshore Africa and to not pursue development of Kossipo in Offshore Africa.

In the North Sea, following a competitive tender for the Ninian South Platform, estimated abandonment and decommissioning costs were higher than originally budgeted. Accordingly, in the third quarter of 2025, the Company updated its cost estimates for the Ninian Central and South Platforms and T-Block (Tiffany, Toni and Thelma fields). Additionally, in the third quarter of 2025, based on current and forecasted economic conditions, including commodity prices and market egress, the Company determined that the T-Block assets were no longer economically viable. As a result, at September 30, 2025, the Company recognized a non-cash charge of $695 million, comprised of a $734 million recoverability charge related to Ninian abandonment costs and a $524 million recoverability charge related to T-Block, net of deferred tax recoveries of $359 million and $204 million, respectively.

Further, during the fourth quarter of 2025, the Company decided to accelerate cessation of production at T-Block to the first quarter of 2027 and de-book associated reserves. This resulted in an additional non-cash charge of $141 million, primarily reflecting revised timing of the abandonment activities and updates to cost estimates, and comprised of a recoverability charge of $204 million, net of deferred tax recoveries of $63 million.

In Offshore Africa, during the fourth quarter of 2025, the Company determined that it would not pursue an extension of its PSC for the Espoir Field, Block CI-26, and de-booked associated crude oil reserves. The Company is working with the Government of Côte d'Ivoire to facilitate the transition of operatorship in the second half of 2026. As a result, the Company recognized a non-cash recoverability charge of $269 million as at December 31, 2025. Additionally, the Company decided not to pursue development of Kossipo in Offshore Africa, and recognized a recoverability charge of $46 million related to the derecognition of its exploration and evaluation assets.

Estimates of asset retirement obligations and related tax recoveries remain subject to revision as abandonment activities progress. Recoverability charges are recognized in depletion, depreciation and amortization expense.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
North America	**$ 58**	$ 57	$ 58	**$ 221**	$ 231
North Sea	**23**	13	17	**64**	65
Offshore Africa	**2**	3	3	**9**	9
Asset retirement obligation accretion	**$ 83**	$ 73	$ 78	**$ 294**	$ 305
$/BOE (1)	**$ 0.85**	$ 0.77	$ 0.89	**$ 0.80**	$ 0.94

(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 year ended December 31, 2025 averaged $0.80 per BOE, a decrease of 15% from $0.94 per BOE for the year ended December 31, 2024. Asset retirement obligation accretion expense for the fourth quarter of 2025 averaged $0.85 per BOE, a decrease of 4% from $0.89 per BOE for the fourth quarter of 2024 and an increase of 10% from $0.77 per BOE for the third quarter of 2025. The decrease in asset retirement obligation accretion expense per BOE for the three months and year ended December 31, 2025 from the comparable periods in 2024 reflected the impact of changes in discount rates at December 31, 2024, combined with higher sales volumes in 2025, partially offset by revisions in cost and timing estimates at December 31, 2024, North America acquisitions completed during 2025, and North Sea cost and timing estimate revisions during 2025. The increase in asset retirement obligation accretion expense per BOE for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected the impact of revisions to cost and timing estimates at September 30, 2025 associated with the North Sea abandonment activities.

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. Record SCO production averaged 619,901 bbl/d in the fourth quarter of 2025 primarily reflecting strong utilization in the Oil Sands Mining and Upgrading segment. The completion of the AOSP asset swap also contributed to increased volumes in the fourth quarter of 2025.

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

	Three Months Ended			Year Ended	
($/bbl)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Realized SCO sales price (1)	**$ 75.90**	$ 87.85	$ 95.08	**$ 86.41**	$ 98.03
Bitumen value for royalty purposes (2)	**$ 58.68**	$ 68.06	$ 69.35	**$ 66.23**	$ 72.68
Bitumen royalties (3)	**$ 9.54**	$ 15.80	$ 17.20	**$ 13.84**	$ 17.23
Transportation (4)	**$ 2.56**	$ 3.86	$ 3.60	**$ 3.31**	$ 2.91

(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 $86.41 per bbl for the year ended December 31, 2025, a decrease of 12% from $98.03 per bbl for the year ended December 31, 2024. The realized SCO sales price averaged $75.90 per bbl for the fourth quarter of 2025, a decrease of 20% from $95.08 per bbl for the fourth quarter of 2024 and a decrease of 14% from $87.85 per bbl for the third quarter of 2025. The decrease in realized SCO sales price per bbl for the three months and year ended December 31, 2025 from the comparable periods primarily reflected lower 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 three months and year ended December 31, 2025 from the comparable periods primarily reflected the decrease in average bitumen value for royalty purposes and the impact of royalty true-ups.

Transportation expense averaged $3.31 per bbl for the year ended December 31, 2025, an increase of 14% from $2.91 per bbl for the year ended December 31, 2024. Transportation expense averaged $2.56 per bbl for the fourth quarter of 2025, a decrease of 29% from $3.60 per bbl for the fourth quarter of 2024 and a decrease of 34% from $3.86 per bbl for the third quarter of 2025. The increase in transportation expense per bbl for the year ended December 31, 2025 from the year ended December 31, 2024 primarily reflected higher volumes shipped on the TMX pipeline in 2025. The decrease in transportation expense per bbl for the fourth quarter of 2025 from the fourth quarter of 2024 primarily reflected lower volumes shipped to the US Gulf Coast, partially offset by higher volumes shipped on the TMX pipeline. The decrease for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected lower volumes shipped to the US Gulf Coast and on the TMX pipeline, as well as a reduction of transportation expense following the recognition of the Corridor pipeline as a leased asset in the fourth quarter.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Production expense, excluding natural gas costs	**$ 1,207**	$ 1,116	$ 991	**$ 4,543**	$ 3,801
Natural gas costs	**46**	19	28	**150**	120
Production expense	**$ 1,253**	$ 1,135	$ 1,019	**$ 4,693**	$ 3,921

	Three Months Ended			Year Ended	
($/bbl)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Production expense, excluding natural gas costs (1)	**$ 21.03**	$ 20.93	$ 20.39	**$ 21.94**	$ 22.18
Natural gas costs (2)	**0.81**	0.36	0.58	**0.72**	0.70
Production expense (3)	**$ 21.84**	$ 21.29	$ 20.97	**$ 22.66**	$ 22.88
Sales volumes (bbl/d)	**624,125**	579,209	528,248	**567,335**	468,280

(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 year ended December 31, 2025 averaged $22.66 per bbl, comparable with $22.88 per bbl for the year ended December 31, 2024. Production expense for the fourth quarter of 2025 averaged $21.84 per bbl, an increase of 4% from $20.97 per bbl for the fourth quarter of 2024 and an increase of 3% from $21.29 per bbl for the third quarter of 2025. The increase in production expense per bbl for the fourth quarter of 2025 from the comparable periods primarily reflected higher energy costs.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Depletion, depreciation and amortization	**$ 762**	$ 713	$ 621	**$ 2,780**	$ 2,258
$/bbl (1)	**$ 13.26**	$ 13.38	$ 12.76	**$ 13.42**	$ 13.17

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

Depletion, depreciation and amortization expense for the year ended December 31, 2025 averaged $13.42 per bbl, comparable with $13.17 per bbl for the year ended December 31, 2024. Depletion, depreciation and amortization expense for the fourth quarter of 2025 of $13.26 per bbl increased 4% from $12.76 per bbl for the fourth quarter of 2024 and was comparable with $13.38 per bbl for the third quarter of 2025. The increase in depletion, depreciation and amortization expense per bbl for the fourth quarter of 2025 from the fourth quarter of 2024 primarily reflected a higher depletable base due to the remeasurement of the AOSP mines and the recognition of the Corridor pipeline as a leased asset following the AOSP asset swap.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Asset retirement obligation accretion	**$ 21**	$ 22	$ 20	**$ 86**	$ 84
$/bbl (1)	**$ 0.37**	$ 0.40	$ 0.44	**$ 0.42**	$ 0.49

(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 year ended December 31, 2025 of $0.42 per bbl decreased 14% from $0.49 per bbl for the year ended December 31, 2024. Asset retirement obligation accretion expense for the fourth quarter of 2025 of $0.37 per bbl decreased 16% from $0.44 per bbl for the fourth quarter of 2024 and decreased 8% from $0.40 per bbl for the third quarter of 2025. The decrease in asset retirement obligation accretion expense per bbl for the three months and year ended December 31, 2025 from the comparable periods primarily reflected the impact of higher sales volumes.

MIDSTREAM AND REFINING

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Product sales					
Midstream activities	**$ 23**	$ 24	$ 21	**$ 91**	$ 82
NWRP, refined product sales and other	**206**	106	193	**670**	813
Segmented revenue	**229**	130	214	**761**	895
Less:					
NWRP, refining toll	**63**	70	65	**262**	295
Midstream activities	**5**	7	5	**22**	20
Production expense	**68**	77	70	**284**	315
NWRP, feedstock costs	**144**	82	160	**503**	669
Transportation expenses	**4**	3	4	**42**	16
Depreciation	**4**	5	3	**17**	16
Segmented earnings (loss)	**$ 9**	$ (37)	$ (23)	**$ (85)**	$ (121)

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 fourth quarter of 2025, production of ultra-low sulphur diesel and other refined products averaged 89,969 BOE/d (22,492 BOE/d to the Company) (three months ended September 30, 2025 – 38,434 BOE/d; 9,608 BOE/d to the Company; three months ended December 31, 2024 – 77,742 BOE/d; 19,436 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at December 31, 2025, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $496 million (December 31, 2024 – $509 million). For the three months ended December 31, 2025, the Company's unrecognized share of the equity loss was $13 million (three months ended September 30, 2025 – recovery of unrecognized equity losses of $21 million; year ended December 31, 2025 – recovery of unrecognized equity losses of $13 million; three months ended December 31, 2024 – recovery of unrecognized equity losses of $1 million; year ended December 31, 2024 – recovery of unrecognized equity losses of $46 million).

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended Dec 31 2025	Sep 30 2025	Dec 31 2024	Year Ended Dec 31 2025	Dec 31 2024
Administration expense	**$ 160**	$ 152	$ 127	**$ 615**	$ 503
$/BOE (1)	**$ 1.04**	$ 1.03	$ 0.95	**$ 1.07**	$ 1.02
Sales volumes (BOE/d) (2)	**1,672,708**	1,606,723	1,460,909	**1,575,845**	1,353,166

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

(2) Total Company sales volumes.

Administration expense for the year ended December 31, 2025 of $1.07 per BOE increased 5% from $1.02 per BOE for the year ended December 31, 2024. Administration expense for the fourth quarter of 2025 of $1.04 per BOE increased 9% from $0.95 per BOE for the fourth quarter of 2024 and was comparable with $1.03 per BOE for the third quarter of 2025. The increase in administration expense per BOE for the year ended December 31, 2025 from the year ended December 31, 2024 primarily reflected higher personnel costs, including incremental costs from recent acquisitions. The increase in administration expense per BOE for the fourth quarter of 2025 from the fourth quarter of 2024 primarily reflected higher personnel costs and lower overhead recoveries.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Dec 31 2025	Sep 30 2025	Dec 31 2024	Year Ended Dec 31 2025	Dec 31 2024
Share-based compensation expense	**$ 83**	$ 63	$ 44	**$ 180**	$ 279

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

The Company recognized $180 million of share-based compensation expense for the year ended December 31, 2025 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 Dec 31 2025	Sep 30 2025	Dec 31 2024	Year Ended Dec 31 2025	Dec 31 2024
Interest and other financing expense	**$ 245**	$ 93	$ 142	**$ 834**	$ 592
Less: Interest (income) and other expense (1)	**(18)**	(174)	(47)	**(205)**	(81)
Interest expense on long-term debt and lease liabilities (1)	**$ 263**	$ 267	$ 189	**$ 1,039**	$ 673
Average current and long-term debt (2)	**$ 18,103**	$ 18,802	$ 13,285	**$ 18,401**	$ 11,895
Average lease liabilities (2)	**2,008**	1,469	1,457	**1,570**	1,509
Average long-term debt and lease liabilities (2)	**$ 20,111**	$ 20,271	$ 14,742	**$ 19,971**	$ 13,404
Average effective interest rate (3) (4)	**5.1%**	5.2%	5.0%	**5.1%**	4.9%
Interest and other financing expense ($/BOE) (5)	**$ 1.60**	$ 0.62	$ 1.06	**$ 1.45**	$ 1.20
Sales volumes (BOE/d) (6)	**1,672,708**	1,606,723	1,460,909	**1,575,845**	1,353,166

(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 year ended December 31, 2025 increased 21% to $1.45 per BOE from $1.20 per BOE for the year ended December 31, 2024. Interest and other financing expense for the fourth quarter of 2025 increased 51% to $1.60 per BOE from $1.06 per BOE for the fourth quarter of 2024 and increased 158% from $0.62 per BOE for the third quarter of 2025. The increase in interest and other financing expense per BOE for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected higher average debt levels, partially offset by higher sales volumes. The increase in interest and other financing expense per BOE for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected the interest income on the deferred PRT and corporate tax recoveries in the North Sea in the third quarter.

The Company's average effective interest rate for the three months and year ended December 31, 2025 was 5.1%, an increase from 4.9% for the year ended December 31, 2024, reflecting higher average long-term debt levels held in 2025, and comparable with the fourth quarter of 2024 and the third quarter of 2025.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Foreign currency forward contracts	**$ (24)**	$ 52	$ 144	**$ (107)**	$ 155
Foreign currency put options [1]	**—**	—	—	**23**	—
Natural gas financial instruments [2] [3] [4] [5]	**(3)**	2	2	**(5)**	13
Net realized (gain) loss	**(27)**	54	146	**(89)**	168
Foreign currency forward contracts	**5**	—	(2)	**—**	15
Natural gas financial instruments [2] [3] [4] [5]	**6**	4	(2)	**14**	(6)
Natural gas embedded derivative [6]	**(88)**	156	—	**57**	—
Net unrealized (gain) loss	**(77)**	160	(4)	**71**	9
Net (gain) loss	**$ (104)**	$ 214	$ 142	**$ (18)**	$ 177

(1) During 2025, the Company periodically entered into foreign currency put options contracts. Further details are disclosed in note 14 to the financial statements.

(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 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.

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

(5) Certain commodity financial instruments were assumed in the acquisition of Painted Pony Energy Ltd. in the fourth quarter of 2020.

(6) 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 gain of $89 million for the year ended December 31, 2025 and a net realized risk management gain of $27 million for the fourth quarter of 2025.

The Company recorded a net unrealized loss of $71 million ($55 million after tax of $16 million) on its risk management activities for the year ended December 31, 2025, and a net unrealized gain of $77 million ($59 million after tax of $18 million) for the fourth quarter of 2025 (three months ended September 30, 2025 – unrealized loss of $160 million ($124 million after tax of $36 million); three months ended December 31, 2024 – unrealized gain of $4 million ($3 million after tax of $1 million); year ended December 31, 2024 – unrealized loss of $9 million ($10 million after tax of $1 million)).

Further details related to outstanding derivative financial instruments as at December 31, 2025 are disclosed in note 14 to the financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Net realized (gain) loss	**$ (13)**	$ 21	$ (62)	**$ 108**	$ 67
Net unrealized (gain) loss	**(193)**	269	782	**(870)**	888
Net (gain) loss [1]	**$ (206)**	$ 290	$ 720	**$ (762)**	$ 955

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

The net realized foreign exchange loss for the year ended December 31, 2025 was primarily related to exchange rate fluctuations on the settlement of US dollar debt, and on the settlement of working capital items denominated in US dollars. The net unrealized foreign exchange gain for the year ended December 31, 2025 was primarily related to the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at December 31, 2025 was US$0.7292 (September 30, 2025 – US$0.7191; December 31, 2024 – US$0.6942).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended Dec 31 2025	Sep 30 2025	Dec 31 2024	Year Ended Dec 31 2025	Dec 31 2024
North America [1]	**$ 596**	$ 499	$ 261	**$ 2,193**	$ 1,654
North Sea	**(16)**	(37)	(11)	**(124)**	(41)
Offshore Africa	**11**	—	35	**16**	57
Current PRT – North Sea	**(51)**	(45)	(67)	**(184)**	(134)
Other taxes	**3**	2	3	**10**	(5)
Current income tax	**543**	419	221	**1,911**	1,531
Deferred corporate income tax	**1,017**	(143)	372	**887**	520
Deferred PRT – North Sea	**(15)**	(389)	(145)	**(377)**	(98)
Deferred income tax	**1,002**	(532)	227	**510**	422
Income tax	**$ 1,545**	$ (113)	$ 448	**$ 2,421**	$ 1,953
Earnings before taxes	**$ 6,848**	$ 487	$ 1,586	**$ 13,241**	$ 8,059
Effective tax rate on net earnings [2]	**23%**	(23)%	28%	**18%**	24%

($ millions, except effective tax rates)	Three Months Ended Dec 31 2025	Sep 30 2025	Dec 31 2024	Year Ended Dec 31 2025	Dec 31 2024
Income tax	**$ 1,545**	$ (113)	$ 448	**$ 2,421**	$ 1,953
Tax effect on non-operating items [3]	**(1,088)**	603	143	**(481)**	175
Current PRT – North Sea	**51**	45	67	**184**	134
Deferred PRT – North Sea	**(26)**	(31)	56	**(84)**	9
Other taxes	**(3)**	(2)	(3)	**(10)**	5
Effective tax on adjusted net earnings	**$ 479**	$ 502	$ 711	**$ 2,030**	$ 2,276
Adjusted net earnings from operations [4]	**$ 1,711**	$ 1,801	$ 1,977	**$ 7,444**	$ 7,414
Adjusted net earnings from operations, before taxes	**$ 2,190**	$ 2,303	$ 2,688	**$ 9,474**	$ 9,690
Effective tax rate on adjusted net earnings from operations [5] [6]	**22%**	22%	26%	**21%**	23%

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

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

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

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

(5) This is a non-GAAP ratio and may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the 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 three months and year ended December 31, 2025 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 three months and year ended December 31, 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 three months and year ended December 31, 2025 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 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]

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Exploration and Production					
Exploration and Evaluation Assets					
Net expenditures	**$ 4**	$ 18	$ 9	**$ 46**	$ 82
Net property (dispositions) acquisitions [3]	**(9)**	45	330	**69**	330
Total Exploration and Evaluation Assets	**(5)**	63	339	**115**	412
Property, Plant and Equipment					
Net property acquisitions [3]	**45**	761	2,553	**1,015**	2,642
Well drilling, completion and equipping	**514**	499	472	**2,107**	1,832
Production and related facilities	**398**	365	341	**1,560**	1,336
Other	**18**	13	14	**50**	53
Total Property, Plant and Equipment	**975**	1,638	3,380	**4,732**	5,863
Total Exploration and Production	**970**	1,701	3,719	**4,847**	6,275
Oil Sands Mining and Upgrading					
Project costs	**92**	76	66	**319**	306
Sustaining capital	**340**	312	357	**1,274**	1,466
Turnaround costs	**8**	13	16	**241**	153
Net property acquisitions [3]	**(212)**	—	6,175	**(212)**	6,173
Other	**4**	2	1	**10**	6
Total Oil Sands Mining and Upgrading	**232**	403	6,615	**1,632**	8,104
Midstream and Refining	**2**	2	1	**8**	11
Head Office	**33**	18	13	**92**	41
Net capital expenditures	**$ 1,237**	$ 2,124	$ 10,348	**$ 6,579**	$ 14,431
Abandonment expenditures	**$ 201**	$ 189	$ 151	**$ 771**	$ 646
By Segment					
North America	**$ 812**	$ 1,606	$ 3,632	**$ 4,364**	$ 6,033
North Sea	**—**	5	3	**16**	39
Offshore Africa	**158**	90	84	**467**	203
Oil Sands Mining and Upgrading	**232**	403	6,615	**1,632**	8,104
Midstream and Refining	**2**	2	1	**8**	11
Head Office	**33**	18	13	**92**	41
Net capital expenditures	**$ 1,237**	$ 2,124	$ 10,348	**$ 6,579**	$ 14,431

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

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

(3) Includes cash consideration paid of $320 million for exploration and evaluation assets and $2,553 million for property, plant and equipment within the North America Exploration and Production segment, and $6,175 million for property, plant and equipment within the Oil Sands Mining and Upgrading segment acquired from Chevron in the fourth quarter of 2024. Includes cash acquired and received as net consideration of $212 million related to the AOSP asset swap within the Oil Sands Mining and Upgrading segment in 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 $6,579 million for the year ended December 31, 2025 compared with $14,431 million for the year ended December 31, 2024. Net capital expenditures were $1,237 million for the fourth quarter of 2025 compared with $10,348 million for the fourth quarter of 2024 and $2,124 million for the third quarter of 2025. In addition, the Company reported abandonment expenditures of $771 million for the year ended December 31, 2025 compared with $646 million for the year ended December 31, 2024. Abandonment expenditures were $201 million for the fourth quarter of 2025 compared with $151 million for the fourth quarter of 2024 and $189 million for the third 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. Subsequent to December 31, 2025, the Company revised its operating capital budget to $5,990 million and increased its production guidance to between 1,615,000 BOE/d and 1,665,000 BOE/d.

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

In February 2026, subsequent to year end, the Company acquired certain producing and non-producing crude oil and NGLs, and natural gas assets in the Peace River area in the North America Exploration and Production segment for cash consideration of approximately $765 million, subject to final closing adjustments. Net assets acquired primarily include exploration and evaluation assets and property, plant and equipment. The Company also assumed associated asset retirement obligations. The 2026 capital budget did not include capital related to this acquisition.

Drilling Activity [(1)] [(2)]

	Three Months Ended			Year Ended	
(number of net wells)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Net successful crude oil wells [(3)]	**114**	89	100	**358**	307
Net successful natural gas wells	**20**	17	14	**78**	78
Dry wells	**1**	—	—	**2**	2
Total	**135**	106	114	**438**	387
Success rate	**99%**	100%	100%	**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 fourth quarter of 2025, the Company drilled 20 net natural gas wells, 67 net primary heavy crude oil wells, 25 net thermal bitumen wells, and 23 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)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024
Adjusted working capital (1)	**$ 42**	$ (303)	$ 174
Long-term debt, net (2)	**$ 15,944**	$ 17,155	$ 18,688
Shareholders' equity	**$ 44,366**	$ 40,461	$ 39,468
Debt to book capitalization (2)	**26.4%**	29.8%	32.1%
After-tax return on average capital employed (3)	**19.5%**	12.8%	12.7%

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

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

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

As at December 31, 2025, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities, and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt are dependent on factors discussed in the 'Business Environment' 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, 2024. 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 2025, the Company extended its $500 million revolving credit facility originally maturing February 2026 to June 2027.
  - During the fourth quarter of 2025, the Company increased its $2,425 million revolving syndicated facility to $2,565 million, and extended $2,425 million originally due June 2027 to June 2029. The remaining $140 million outstanding under this facility will mature in June 2027. Each of the revolving credit facilities are extendible annually at the mutual agreement of the Company and lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.
  - Borrowings under the Company's credit facilities may be made by way of pricing referenced to CORRA, SOFR, US base rate or Canadian prime rate.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - During the first quarter of 2025, the Company repaid US$600 million of 3.90% US dollar debt securities due February 2025.
  - During the third quarter of 2025, the Company repaid US$600 million of 2.05% US dollar debt securities due July 2025.

- During the third quarter of 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- During the fourth quarter of 2025, the Company issued $550 million of 3.30% medium-term notes due December 2028, $550 million of 3.75% medium-term notes due February 2031, and $550 million of 4.55% medium-term notes due February 2036. After issuing these securities, the Company had $1,350 million remaining on its base shelf prospectus.
- During the third quarter of 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$4,500 million of debt securities in the United States, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- During the fourth quarter of 2025, the Company filed a prospectus supplement to the base shelf prospectus. Under the base shelf prospectus, the Company completed the exchange of US$747 million of the outstanding restricted 5.00% US dollar debt securities due December 2029 and US$750 million of the outstanding restricted 5.40% US dollar debt securities due December 2034. The exchanged notes were not subject to transfer restrictions and did not impact the Company's level of indebtedness. After the exchange of these securities, the Company had US$3,003 million remaining on its base shelf prospectus.

As at December 31, 2025, the Company had undrawn bank credit facilities of $5,668 million, and a fully drawn non-revolving term credit facility of $4,000 million. Including cash and cash equivalents, the Company had approximately $6,341 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit.

Long-term debt, net was $15,944 million as at December 31, 2025 (December 31, 2024 – $18,688 million), resulting in a debt to book capitalization ratio of 26.4% (December 31, 2024 – 32.1%); this ratio was within the 25% to 45% internal range utilized by management. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2025, the Company was in compliance with this covenant.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt as at December 31, 2025 are discussed in note 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 December 31, 2025, the maturity dates of certain financial liabilities, including long-term debt and other long-term liabilities and related interest payments, were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt [(1)]	$ 441	$ 5,637	$ 2,489	$ 8,140
Other long-term liabilities [(2)]	$ 381	$ 268	$ 659	$ 1,863
Interest and other financing expense [(3)]	$ 971	$ 910	$ 1,860	$ 3,678

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

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

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

Share Capital

As at December 31, 2025, there were 2,081,578,000 common shares outstanding (December 31, 2024 – 2,102,996,000 common shares) and 54,734,000 stock options outstanding (December 31, 2024 – 50,806,000 stock options). As at March 3, 2026, the Company had 2,085,972,000 common shares outstanding and 57,252,000 stock options outstanding.

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

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

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

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

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

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

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

COMMITMENTS AND CONTINGENCIES

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

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

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

(2) In the fourth quarter of 2025, in connection with the AOSP asset swap, the Company became the sole contracted shipper on the Corridor pipeline. Previously, the Company recognized a commitment associated with the pipeline, however, following the completion of the AOSP asset swap the contract has been recorded as a lease. Further details on the AOSP asset swap are disclosed in note 4 to the financial statements.

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

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

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, 2024.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the year ended December 31, 2025 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.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Net earnings	**$ 5,303**	$ 600	$ 1,138	**$ 10,820**	$ 6,106
Share-based compensation, net of tax (1)	**79**	59	39	**166**	257
Unrealized risk management (gain) loss, net of tax (2)	**(59)**	124	(3)	**55**	10
Unrealized foreign exchange (gain) loss, net of tax (3)	**(193)**	269	782	**(870)**	888
Realized foreign exchange (gain) loss on financing activities, net of tax (4)	**(23)**	54	—	**54**	135
Gain from investment, net of tax	**—**	—	—	**—**	(50)
Gain on acquisitions, disposition, and remeasurement, net of tax (5) (6)	**(3,845)**	—	—	**(3,925)**	—
Recoverability charges, net of tax (7) (8)	**449**	695	21	**1,144**	68
Non-operating items, net of tax	**(3,592)**	1,201	839	**(3,376)**	1,308
Adjusted net earnings from operations	**$ 1,711**	$ 1,801	$ 1,977	**$ 7,444**	$ 7,414

(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 December 31, 2025 was an expense of $83 million (three months ended September 30, 2025 – $63 million expense; three months ended December 31, 2024 – $44 million expense; year ended December 31, 2025 – $180 million expense; year ended December 31, 2024 – $279 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 gain for the three months ended December 31, 2025 was $77 million (three months ended September 30, 2025 – $160 million loss; three months ended December 31, 2024 – $4 million gain; year ended December 31, 2025 – $71 million loss; year ended December 31, 2024 – $9 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 second quarter of 2025, the Company acquired an interest in certain producing and non-producing crude oil and NGLs, and natural gas assets in the North America Exploration and Production segment, resulting in a pre- and after-tax gain on acquisition of $80 million representing the excess of the fair value of the net assets acquired compared to the total purchase consideration.

(6) 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. The transaction is discussed further in the 'Summary of Financial Highlights' section of this MD&A.

(7) For the three months ended December 31, 2025, the Company recognized a pre-tax non-cash recoverability charge of $204 million ($141 million after-tax) (three months ended September 30, 2025 – $1,258 million ($695 million after-tax); year ended December 31, 2025 – $1,462 million ($836 million after-tax); three months ended December 31, 2024 – $160 million ($21 million after-tax)) in depletion, depreciation and amortization expense relating to the North Sea abandonment and decommissioning activities. The costs are included in capital and abandonment expenditures, consistent with the treatment of all abandonment related expenditures for the purpose of the Company's non-GAAP measures. Recoverability charges are discussed in the 'Adjusted Depletion, Depreciation and Amortization – Exploration and Production' section of this MD&A.

(8) For the three months ended December 31, 2025, the Company recognized pre-tax non-cash recoverability charges of $315 million ($308 million after-tax) (three months ended June 30, 2024 – $62 million ($47 million after-tax)) in depletion, depreciation and amortization expense relating to Offshore Africa. Recoverability charges are discussed in the 'Adjusted Depletion, Depreciation and Amortization – Exploration and Production' section of this MD&A.

Adjusted Funds Flow

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Cash flows from operating activities	**$ 3,768**	$ 3,940	$ 3,432	**$ 15,106**	$ 13,386
Net change in non-cash working capital	**(134)**	(432)	563	**(672)**	743
Abandonment expenditures	**201**	189	151	**771**	646
Movements in other long-term assets (1)	**(87)**	223	40	**255**	84
Adjusted funds flow	**$ 3,748**	$ 3,920	$ 4,186	**$ 15,460**	$ 14,859

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

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

Adjusted net earnings from operations and adjusted funds flow, per common share (basic and diluted) are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 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.

During the first quarter of 2025, the Company revised its presentation of transportation expense and blending and feedstock costs, showing the expenses on a disaggregated basis in the consolidated statements of earnings. Previously, the Company aggregated transportation, blending and feedstock costs. The revision provides users with more information to evaluate the Company’s performance. The financial statements and this MD&A have been updated for all periods presented. As a result, Transportation ($/BOE, $/bbl and $/Mcf) is no longer considered a non-GAAP ratio.

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

Realized price ($/bbl and $/BOE) is a non-GAAP ratio calculated as realized crude oil and NGLs sales and total realized BOE sales (non-GAAP financial measures) divided by respective sales volumes. Realized crude oil and NGLs sales and total realized BOE sales is comprised of crude oil and NGLs sales and natural gas sales less blending and feedstock costs and other by-product sales, as disclosed in note 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.

	Three Months Ended			Year Ended	
($ millions, except bbl/d and $/bbl)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs (bbl/d)					
North America	**590,144**	577,089	533,126	**570,262**	504,339
International					
North Sea	**10,804**	3,455	10,686	**9,146**	11,455
Offshore Africa	**4,318**	2,313	8,423	**4,520**	11,198
Total International	**15,122**	5,768	19,109	**13,666**	22,653
Total sales volumes	**605,266**	582,857	552,235	**583,928**	526,992
Crude oil and NGLs sales (1)	**$ 4,539**	$ 4,773	$ 4,999	**$ 19,591**	$ 19,641
Less: Blending and feedstock costs (2)	**951**	883	1,177	**4,344**	4,643
Realized crude oil and NGLs sales	**$ 3,588**	$ 3,890	$ 3,822	**$ 15,247**	$ 14,998
Realized price ($/bbl)	**$ 64.42**	$ 72.57	$ 75.22	**$ 71.54**	$ 77.76

(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.

	Three Months Ended			Year Ended	
($ millions, except BOE/d and $/BOE)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Barrels of oil equivalent (BOE/d)					
North America	**1,032,973**	1,020,062	911,869	**993,279**	860,367
International					
North Sea	**11,292**	3,791	11,285	**9,656**	11,791
Offshore Africa	**4,318**	3,661	9,507	**5,575**	12,728
Total International	**15,610**	7,452	20,792	**15,231**	24,519
Total sales volumes	**1,048,583**	1,027,514	932,661	**1,008,510**	884,886
Barrels of oil equivalent sales (1)	**$ 5,247**	$ 5,139	$ 5,424	**$ 21,921**	$ 21,105
Less: Blending and feedstock costs (2)	**951**	883	1,177	**4,344**	4,643
Less: Sulphur (income) expense	**(30)**	(28)	(3)	**(85)**	3
Realized barrels of oil equivalent sales	**$ 4,326**	$ 4,284	$ 4,250	**$ 17,662**	$ 16,459
Realized price ($/BOE)	**$ 44.85**	$ 45.31	$ 49.54	**$ 47.98**	$ 50.82

(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.

	Three Months Ended			Year Ended	
($ millions, except $/bbl and royalty rates)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs sales (1)	**$ 4,417**	$ 4,724	$ 4,830	**$ 19,102**	$ 18,740
Less: Blending and feedstock costs (2)	**951**	883	1,177	**4,344**	4,643
Realized crude oil and NGLs sales	**$ 3,466**	$ 3,841	$ 3,653	**$ 14,758**	$ 14,097
Realized crude oil and NGLs prices ($/bbl)	**$ 63.83**	$ 72.35	$ 74.46	**$ 70.90**	$ 76.37
Crude oil and NGLs royalties (3)	**$ 525**	$ 702	$ 747	**$ 2,450**	$ 2,842
Crude oil and NGLs royalty rates	**15%**	18%	20%	**17%**	20%

(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.

	Three Months Ended			Year Ended	
($ millions, except for bbl/d and $/bbl)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
SCO sales volumes (bbl/d)	**624,125**	579,209	528,248	**567,335**	468,280
Crude oil and NGLs sales (1)	**$ 4,955**	$ 5,255	$ 5,362	**$ 20,112**	$ 19,263
Less: Blending and feedstock costs (2)	**597**	573	741	**2,218**	2,462
Realized SCO sales	**$ 4,358**	$ 4,682	$ 4,621	**$ 17,894**	$ 16,801
Realized SCO sales price ($/bbl)	**$ 75.90**	$ 87.85	$ 95.08	**$ 86.41**	$ 98.03

(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.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Cash flows used in investing activities	**$ 1,200**	$ 2,234	$ 10,414	**$ 6,687**	$ 14,095
Working capital acquired from Chevron	**—**	—	(115)	**—**	(115)
Net proceeds from investment	**—**	—	—	**—**	575
Net change in non-cash working capital	**37**	(110)	49	**(108)**	(124)
Net capital expenditures	**1,237**	2,124	10,348	**6,579**	14,431
Abandonment expenditures	**201**	189	151	**771**	646
Capital and abandonment expenditures	**$ 1,438**	$ 2,313	$ 10,499	**$ 7,350**	$ 15,077

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)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024
Undrawn bank credit facilities	**$ 5,668**	$ 4,201	$ 4,562
Cash and cash equivalents	**673**	113	131
Liquidity	**$ 6,341**	$ 4,314	$ 4,693

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)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024
Long-term debt	**$ 16,617**	$ 17,268	$ 18,819
Less: Cash and cash equivalents	**673**	113	131
Long-term debt, net	**$ 15,944**	$ 17,155	$ 18,688

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)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024
Interest adjusted after-tax return:			
Net earnings, 12 months trailing (1)	**$ 10,820**	$ 6,655	$ 6,106
Interest and other financing expense, net of tax, 12 months trailing (2)	**640**	561	454
Interest adjusted after-tax return	**$ 11,460**	$ 7,216	$ 6,560
12 months average current portion long-term debt (3)	**$ 1,293**	$ 1,529	$ 1,525
12 months average long-term debt (3)	**16,149**	14,596	10,642
12 months average common shareholders' equity (3)	**41,208**	40,314	39,635
12 months average capital employed	**$ 58,650**	$ 56,439	$ 51,802
After-tax return on average capital employed	**19.5%**	12.8%	12.7%

(1) Net earnings, 12 months trailing for the fourth quarter of 2025 includes a gain on acquisition, disposition, and remeasurement of $4,989 million associated with the AOSP asset swap. Further details are disclosed in note 4 to the financial statements.

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

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

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

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

Commitments and contingencies (note 15)

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

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Dec 31 2025	Three Months Ended Dec 31 2024	Year Ended Dec 31 2025	Year Ended Dec 31 2024
Product sales	16	**$ 10,710**	$ 11,064	**$ 44,167**	$ 41,509
Less: royalties		**(1,101)**	(1,596)	**(5,405)**	(5,853)
Revenue		**9,609**	9,468	**38,762**	35,656
Expenses					
Production		**2,404**	2,008	**9,155**	8,093
Blending and feedstock		**1,856**	2,091	**8,071**	7,931
Transportation		**670**	609	**2,751**	2,053
Depletion, depreciation and amortization [1]	3,4,5	**2,538**	1,901	**9,384**	6,681
Administration		**160**	127	**615**	503
Share-based compensation	8	**83**	44	**180**	279
Asset retirement obligation accretion	8	**104**	98	**380**	389
Interest and other financing expense		**245**	142	**834**	592
Risk management (gain) loss	14	**(104)**	142	**(18)**	177
Foreign exchange (gain) loss		**(206)**	720	**(762)**	955
Gain on acquisitions, disposition, and remeasurement	4	**(4,989)**	—	**(5,069)**	—
Gain from investment		**—**	—	**—**	(56)
		2,761	7,882	**25,521**	27,597
Earnings before taxes		**6,848**	1,586	**13,241**	8,059
Current income tax expense	9	**543**	221	**1,911**	1,531
Deferred income tax expense	9	**1,002**	227	**510**	422
Net earnings		**$ 5,303**	$ 1,138	**$ 10,820**	$ 6,106
Net earnings per common share					
Basic	13	**$ 2.55**	$ 0.54	**$ 5.17**	$ 2.87
Diluted	13	**$ 2.54**	$ 0.54	**$ 5.16**	$ 2.85

(1) Depletion, depreciation and amortization expense for the year ended December 31, 2025 includes a $1,462 million non-cash recoverability charge for revisions to abandonment and decommissioning costs in the North Sea, a $269 million non-cash recoverability charge related to the decision to not pursue an extension of the Company's Production Sharing Contract ("PSC") for the Espoir field in Offshore Africa, and a $46 million non-cash derecognition of exploration and evaluation assets related to the decision to not pursue development of Kossipo in Offshore Africa (notes 3 and 4).

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2025	Three Months Ended Dec 31 2024	Year Ended Dec 31 2025	Year Ended Dec 31 2024
Net earnings	**$ 5,303**	$ 1,138	**$ 10,820**	$ 6,106
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 $1 million (2024 – $nil) – three months ended; $2 million (2024 – $nil) – year ended	**3**	1	**18**	2
Reclassification to net earnings, net of taxes of $nil (2024 – $nil) – three months ended; $2 million (2024 – $nil) – year ended	**(6)**	(1)	**(22)**	(4)
	(3)	—	**(4)**	(2)
Foreign currency translation adjustment				
Translation of net investment	**(13)**	101	**(78)**	131
Other comprehensive (loss) income, net of taxes	**(16)**	101	**(82)**	129
Comprehensive income	**$ 5,287**	$ 1,239	**$ 10,738**	$ 6,235

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended Dec 31 2025	Year Ended Dec 31 2024
Share capital	10		
Balance – beginning of year		**$ 11,064**	$ 10,712
Issued upon exercise of stock options		**264**	280
Previously recognized liability on stock options exercised for common shares		**273**	358
Purchase of common shares under Normal Course Issuer Bid		**(180)**	(286)
Balance – end of year		**11,421**	11,064
Retained earnings			
Balance – beginning of year		**28,103**	28,948
Net earnings		**10,820**	6,106
Dividends on common shares	10	**(4,910)**	(4,537)
Purchase of common shares under Normal Course Issuer Bid, including tax	10	**(1,287)**	(2,414)
Balance – end of year		**32,726**	28,103
Accumulated other comprehensive income	11		
Balance – beginning of year		**301**	172
Other comprehensive (loss) income, net of taxes		**(82)**	129
Balance – end of year		**219**	301
Shareholders' equity		**$ 44,366**	$ 39,468

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Dec 31 2025	Three Months Ended Dec 31 2024	Year Ended Dec 31 2025	Year Ended Dec 31 2024
Operating activities					
Net earnings		**$ 5,303**	$ 1,138	**$ 10,820**	$ 6,106
Non-cash items					
Depletion, depreciation and amortization	3,4,5	**2,538**	1,901	**9,384**	6,681
Share-based compensation		**83**	44	**180**	279
Asset retirement obligation accretion		**104**	98	**380**	389
Unrealized risk management (gain) loss	14	**(77)**	(4)	**71**	9
Unrealized foreign exchange (gain) loss		**(193)**	782	**(870)**	888
Gain on acquisitions, disposition, and remeasurement	4	**(4,989)**	—	**(5,069)**	—
Gain from investment		**—**	—	**—**	(50)
Deferred income tax expense		**1,002**	227	**510**	422
Realized foreign exchange on financing activities [(1)]		**(23)**	—	**54**	135
Abandonment expenditures	8	**(201)**	(151)	**(771)**	(646)
Other		**87**	(40)	**(255)**	(84)
Net change in non-cash working capital		**134**	(563)	**672**	(743)
Cash flows from operating activities		**3,768**	3,432	**15,106**	13,386
Financing activities					
(Repayment) issuance of bank credit facilities and commercial paper, net	7	**(2,087)**	5,466	**(1,395)**	5,466
Issuance of other long-term debt	7	**1,634**	2,639	**1,634**	2,639
Repayment of other long-term debt	7	**—**	—	**(1,699)**	(1,008)
Payment of lease liabilities	5	**(108)**	(84)	**(361)**	(325)
Issuance of common shares on exercise of stock options	10	**73**	32	**264**	280
Dividends on common shares		**(1,226)**	(1,110)	**(4,871)**	(4,429)
Purchase of common shares under Normal Course Issuer Bid	10	**(294)**	(551)	**(1,449)**	(2,660)
Cash flows (used in) from financing activities		**(2,008)**	6,392	**(7,877)**	(37)
Investing activities					
Net proceeds (expenditures) on exploration and evaluation assets	3,16	**5**	(19)	**(115)**	(92)
Net expenditures on property, plant and equipment	4,16	**(1,454)**	(1,281)	**(6,676)**	(5,291)
Cash from AOSP asset swap	4	**212**	—	**212**	—
Acquisition of Chevron's assets	4,16	**—**	(9,163)	**—**	(9,163)
Net proceeds from investment		**—**	—	**—**	575
Net change in non-cash working capital		**37**	49	**(108)**	(124)
Cash flows used in investing activities		**(1,200)**	(10,414)	**(6,687)**	(14,095)
Increase (decrease) in cash and cash equivalents		**560**	(590)	**542**	(746)
Cash and cash equivalents – beginning of period		**113**	721	**131**	877
Cash and cash equivalents – end of period		**$ 673**	$ 131	**$ 673**	$ 131
Interest paid on long-term debt		**$ 238**	$ 105	**$ 978**	$ 586
Income taxes paid, net		**$ 525**	$ 187	**$ 1,722**	$ 1,144

(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.

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, 2024. 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, 2024.

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

During the second quarter of 2025, the Company entered into a long-term natural gas supply agreement that contains an embedded derivative (note 14). Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not closely related to the host contract, except when the host contract is an asset.

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, including uncertainties around US imposed tariffs. While these actions have contributed to market volatility, including commodity price and foreign exchange volatility, these tariffs have not had a material impact on the Company's results for the year ended December 31, 2025. The duration of these trade actions remains uncertain, and broader changes to US economic policy may impact the estimates, assumptions, and judgements used in the preparation of the interim consolidated financial statements. Accordingly, actual results may differ from estimated amounts, and those differences may be material.

2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2024	$ 2,408	$ —	$ 48	$ 70	$ 2,526
Additions/Acquisitions, net (1)	**207**	**—**	**—**	**1**	**208**
Transfers to property, plant and equipment	**(21)**	**—**	**—**	**(14)**	**(35)**
Derecognitions and other (2)	**—**	**—**	**(46)**	**—**	**(46)**
Foreign exchange adjustments	**—**	**—**	**(2)**	**—**	**(2)**
At December 31, 2025	**$ 2,594**	**$ —**	**$ —**	**$ 57**	**$ 2,651**

(1) Refer to note 4 for further details on acquisitions completed during the year.

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

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, 2024	$ 88,964	$ 9,731	$ 5,023	$ 57,345	$ 495	$ 607	$ 162,165
Additions/Acquisitions, net	**4,631**	**12**	**467**	**1,844**	**8**	**92**	**7,054**
Transfers from exploration and evaluation assets	**21**	**—**	**—**	**14**	**—**	**—**	**35**
Change in asset retirement obligation estimates	**(184)**	**1,211**	**80**	**(3)**	**—**	**—**	**1,104**
Derecognitions [1]	**(536)**	**(1,207)**	**—**	**(814)**	**—**	**—**	**(2,557)**
AOSP mines acquisition (100%) [2]	**—**	**—**	**—**	**15,488**	**—**	**—**	**15,488**
AOSP mines disposition (90%) [2]	**—**	**—**	**—**	**(12,087)**	**—**	**—**	**(12,087)**
Scotford and Quest disposition (10%) [2]	**—**	**—**	**—**	**(1,217)**	**—**	**—**	**(1,217)**
Foreign exchange adjustments and other	**—**	**(477)**	**(254)**	**—**	**—**	**—**	**(731)**
At December 31, 2025	**$ 92,896**	**$ 9,270**	**$ 5,316**	**$ 60,570**	**$ 503**	**$ 699**	**$ 169,254**
Accumulated depletion and depreciation							
At December 31, 2024	$ 62,010	$ 9,392	$ 3,885	$ 12,765	$ 229	$ 470	$ 88,751
Expense	**4,470**	**92**	**97**	**2,538**	**17**	**31**	**7,245**
Derecognitions [1]	**(536)**	**(1,207)**	**—**	**(814)**	**—**	**—**	**(2,557)**
AOSP mines disposition (90%) [2]	**—**	**—**	**—**	**(2,656)**	**—**	**—**	**(2,656)**
Scotford and Quest disposition (10%) [2]	**—**	**—**	**—**	**(206)**	**—**	**—**	**(206)**
Recoverability charges	**—**	**1,462**	**269**	**—**	**—**	**—**	**1,731**
Foreign exchange adjustments and other	**(4)**	**(469)**	**(216)**	**(10)**	**—**	**—**	**(699)**
At December 31, 2025	**$ 65,940**	**$ 9,270**	**$ 4,035**	**$ 11,617**	**$ 246**	**$ 501**	**$ 91,609**
Net book value							
At December 31, 2025	**$ 26,956**	**$ —**	**$ 1,281**	**$ 48,953**	**$ 257**	**$ 198**	**$ 77,645**
At December 31, 2024	$ 26,954	$ 339	$ 1,138	$ 44,580	$ 266	$ 137	$ 73,414

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

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

AOSP Asset Swap Transaction

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

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

a) Net Assets Acquired and Consideration Exchanged

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

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

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

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

b) Gain on Acquisition, Disposition, and Remeasurement

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

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

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

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

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

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

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

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

North America Exploration and Production Acquisitions in 2025

During the year ended December 31, 2025, the Company acquired a number of producing and non-producing crude oil and NGLs, and natural gas assets in the North America Exploration and Production segment. These transactions were accounted for using the business combination method of accounting and are summarized below.

a) Grande Prairie NGLs and Natural Gas Acquisition

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

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

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

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

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

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

If the Grande Prairie and Palliser Block acquisitions had been completed on January 1, 2025, the Company estimates that pro forma revenue would have increased by approximately $961 million and pro forma net operating income (comprised of revenue less production and transportation expense) would have increased by approximately $520 million for the year ended December 31, 2025. Including the impact of depletion, depreciation and amortization, the Company estimates pro forma earnings before taxes would have increased by approximately $241 million for the year ended December 31, 2025.

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

d) Other Acquisitions

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

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

International Matters

a) North Sea

The Company is advancing abandonment and decommissioning activities in the North Sea. Following a 2025 competitive tender for the Ninian South Platform, estimated abandonment costs were higher than originally budgeted. Accordingly, the Company updated its abandonment and decommissioning cost estimates for the Ninian Central and South Platforms and T-Block (Tiffany, Toni and Thelma fields). Additionally, based on current and forecasted economic conditions, including commodity prices and market egress, the Company determined that the T-Block assets were no longer economically viable. As a result, at September 30, 2025, the Company recognized a non-cash charge of $695 million, comprised of a $734 million recoverability charge recognized in depletion, depreciation and amortization expense related to Ninian abandonment costs, and a $524 million recoverability charge recognized in depletion, depreciation and amortization expense related to T-Block, net of deferred tax recoveries of $359 million and $204 million, respectively.

During the fourth quarter of 2025, the Company decided to accelerate cessation of production for T-Block to the first quarter of 2027 and de-book associated crude oil reserves. This resulted in an additional non-cash charge of $141 million, primarily reflecting revised timing of the abandonment activities and updates to cost estimates, and comprised of a recoverability charge recognized in depletion, depreciation and amortization expense of $204 million, net of deferred tax recoveries of $63 million. Estimates of asset retirement obligations and related tax recoveries remain subject to revision as abandonment activities progress. Recoverability charges are recognized in depletion, depreciation and amortization expense.

b) Offshore Africa

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

Other Matters

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

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

5. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2024	$ 752	$ 468	$ 64	$ 110	$ 1,394
Additions [1]	**1,554**	**413**	**45**	**43**	**2,055**
Depreciation	**(100)**	**(208)**	**(30)**	**(24)**	**(362)**
Derecognitions	**(3)**	**(29)**	**(29)**	**—**	**(61)**
Foreign exchange adjustments and other	**(4)**	**(10)**	**(7)**	**(4)**	**(25)**
At December 31, 2025	**$ 2,199**	**$ 634**	**$ 43**	**$ 125**	**$ 3,001**

(1) In the fourth quarter of 2025, in connection with the AOSP asset swap (note 4), the Company became the sole contracted shipper on the Corridor pipeline and recognized $1,510 million of lease assets, with an associated reduction in the Company's product transportation, purchases, and processing commitments (note 15).

Lease liabilities

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

	Dec 31 2025	Dec 31 2024
Lease liabilities	**$ 3,106**	$ 1,464
Less: current portion	**373**	255
	$ 2,733	$ 1,209

Total cash outflows for leases for the three months ended December 31, 2025, including payments related to short-term leases not reported as lease assets, were $350 million (three months ended December 31, 2024 – $346 million; year ended December 31, 2025 – $1,458 million; year ended December 31, 2024 – $1,333 million). Interest expense on leases for the three months ended December 31, 2025 was $27 million (three months ended December 31, 2024 – $16 million; year ended December 31, 2025 – $74 million; year ended December 31, 2024 – $69 million).

6. OTHER LONG-TERM ASSETS

	Dec 31 2025	Dec 31 2024
Long-term prepayments, contracts and other [(1)]	**$ 419**	$ 313
Prepaid cost of service tolls	**229**	166
Long-term inventory	**291**	204
Risk management (note 14)	**—**	13
	939	696
Less: current portion	**70**	76
	$ 869	$ 620

(1) Includes physical product sales contracts, interest on Petroleum Revenue Tax ("PRT") and corporate tax recoveries in the North Sea (note 4), 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 December 31, 2025, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $496 million (December 31, 2024 – $509 million). For the three months ended December 31, 2025, the Company's unrecognized share of the equity loss was $13 million (year ended December 31, 2025 – recovery of unrecognized equity losses of $13 million; three months ended December 31, 2024 – recovery of unrecognized equity losses of $1 million; year ended December 31, 2024 – recovery of unrecognized equity losses of $46 million).

7. LONG-TERM DEBT

	Dec 31 2025	Dec 31 2024
Canadian dollar denominated debt, unsecured		
Medium-term notes	**$ 3,116**	$ 1,466
US dollar denominated debt, unsecured		
Bank credit facilities (December 31, 2025 – US$2,860 million; December 31, 2024 – US$3,393 million)	**3,922**	4,888
Commercial paper (December 31, 2025 – US$nil; December 31, 2024 – US$467 million)	**—**	672
US dollar debt securities (December 31, 2025 – US$7,050 million; December 31, 2024 – US$8,250 million)	**9,669**	11,883
	16,707	18,909
Less: original issue discounts, net [(1)]	**14**	12
transaction costs [(1)] [(2)]	**76**	78
	16,617	18,819
Less: current portion of commercial paper	**—**	672
current portion of long-term debt [(1)] [(2)]	**441**	1,728
	$ 16,176	$ 16,419

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

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

Bank Credit Facilities and Commercial Paper

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

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

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

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

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

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

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

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

Medium-Term Notes

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

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

US Dollar Debt Securities

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

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

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

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

8. OTHER LONG-TERM LIABILITIES

		Dec 31 2025		Dec 31 2024
Asset retirement obligations	**$**	**9,743**	$	8,607
Lease liabilities (note 5)		**3,106**		1,464
Share-based compensation		**433**		620
Transportation and processing contracts		**186**		58
Risk management (note 14)		**65**		8
Other		**68**		80
		13,601		10,837
Less: current portion		**1,665**		1,535
	$	**11,936**	$	9,302

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 4.9% (December 31, 2024 – 4.8%) and inflation rates of up to 2% (December 31, 2024 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

		Dec 31 2025		Dec 31 2024
Balance – beginning of year	**$**	**8,607**	$	7,690
Liabilities incurred		**34**		28
Liabilities acquired, net		**489**		171
Liabilities settled		**(771)**		(646)
Asset retirement obligation accretion		**380**		389
Revision of cost, inflation, and timing estimates (1)		**1,233**		417
Change in discount rates		**(129)**		419
Foreign exchange adjustments		**(100)**		139
Balance – end of year		**9,743**		8,607
Less: current portion		**956**		787
	$	**8,787**	$	7,820

(1) Includes normal course revisions of cost, inflation, and timing estimates, as well as revisions to decommissioning timing and costs in the North Sea and Offshore Africa (note 4).

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.

	Dec 31 2025	Dec 31 2024
Balance – beginning of year	**$ 620**	$ 780
Share-based compensation expense	**180**	279
Cash payment for stock options surrendered and PSUs vested	**(94)**	(84)
Transferred to common shares	**(273)**	(358)
Other	**—**	3
Balance – end of year	**433**	620
Less: current portion	**312**	463
	$ 121	$ 157

9. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Year Ended	
Expense (recovery)	**Dec 31 2025**	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Current corporate income tax – North America [1]	**$ 596**	$ 261	**$ 2,193**	$ 1,654
Current corporate income tax – North Sea	**(16)**	(11)	**(124)**	(41)
Current corporate income tax – Offshore Africa	**11**	35	**16**	57
Current PRT [2] – North Sea	**(51)**	(67)	**(184)**	(134)
Other taxes	**3**	3	**10**	(5)
Current income tax	**543**	221	**1,911**	1,531
Deferred corporate income tax	**1,017**	372	**887**	520
Deferred PRT [2] – North Sea	**(15)**	(145)	**(377)**	(98)
Deferred income tax	**1,002**	227	**510**	422
Income tax	**$ 1,545**	$ 448	**$ 2,421**	$ 1,953

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

(2) Petroleum Revenue Tax.

For the year ended December 31, 2025, in connection with the AOSP asset swap, the Company recognized deferred corporate income tax of $1,037 million related to the gain on remeasurement of the previously held interest in the AOSP mines, and deferred corporate income tax of $107 million related to the gain on disposition of the 10% interest in Scotford and Quest. Refer to note 4 for further details on the transaction.

For the year ended December 31, 2025, the Company recognized deferred tax recoveries comprised of a deferred corporate income tax recovery of $165 million (December 31, 2024 – $50 million) and a deferred PRT recovery of $461 million (December 31, 2024 – $89 million) in connection with the increase in the Company's estimate of future abandonment costs for the planned decommissioning activities at the Ninian field and T-Block in the North Sea (note 4).

10. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued Common Shares	Year Ended Dec 31, 2025 Number of shares (thousands)		Amount
Balance – beginning of year	**2,102,996**	**$**	**11,064**
Issued upon exercise of stock options	**12,062**		**264**
Previously recognized liability on stock options exercised for common shares	**—**		**273**
Purchase of common shares under Normal Course Issuer Bid	**(33,480)**		**(180)**
Balance – end of year	**2,081,578**	**$**	**11,421**

Dividends

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

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

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

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

Normal Course Issuer Bid

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

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

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

Share-Based Compensation – Stock Options

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

	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of year	**50,806**	**$ 33.90**
Granted	**19,457**	**43.53**
Exercised for common shares	**(12,062)**	**21.86**
Surrendered for cash settlement	**(524)**	**22.65**
Forfeited	**(2,943)**	**38.57**
Outstanding – end of year	**54,734**	**$ 39.83**
Exercisable – end of year	**11,942**	**$ 36.58**

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:

	Dec 31 2025	Dec 31 2024
Derivative financial instruments designated as cash flow hedges	**$ 66**	$ 70
Foreign currency translation adjustment	**153**	231
	$ 219	$ 301

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 December 31, 2025, the ratio was within the target range at 26.4%.

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.

	Dec 31 2025	Dec 31 2024
Long-term debt	**$ 16,617**	$ 18,819
Less: cash and cash equivalents	**673**	131
Long-term debt, net	**$ 15,944**	$ 18,688
Total shareholders' equity	**$ 44,366**	$ 39,468
Debt to book capitalization	**26.4%**	32.1%

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

13. NET EARNINGS PER COMMON SHARE

		Three Months Ended		Year Ended	
		Dec 31 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Weighted average common shares outstanding – basic (thousands of shares)		**2,083,142**	2,108,047	**2,091,134**	2,125,804
Effect of dilutive stock options (thousands of shares)		**6,035**	12,336	**6,772**	14,625
Weighted average common shares outstanding – diluted (thousands of shares)		**2,089,177**	2,120,383	**2,097,906**	2,140,429
Net earnings		**$ 5,303**	$ 1,138	**$ 10,820**	$ 6,106
Net earnings per common share	– basic	**$ 2.55**	$ 0.54	**$ 5.17**	$ 2.87
	– diluted	**$ 2.54**	$ 0.54	**$ 5.16**	$ 2.85

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)	**Dec 31 2025**	Dec 31 2024
Balance – beginning of year	**$ 5**	$ 9
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities (1) (2) (3) (4) (5)	**(68)**	(6)
Foreign exchange	**(1)**	1
Other comprehensive income	**(1)**	1
Balance – end of year	**(65)**	5
Less: current portion	**(8)**	5
	$ (57)	$ —

(1) Risk management assets and liabilities are disclosed in note 6 and note 8, respectively.

(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.

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

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

	Three Months Ended		Year Ended	
	Dec 31 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Net realized risk management (gain) loss	**$ (27)**	$ 146	**$ (89)**	$ 168
Net unrealized risk management (gain) loss	**(77)**	(4)	**71**	9
	$ (104)	$ 142	**$ (18)**	$ 177

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:

	Dec 31, 2025	
	Carrying amount	**Level 1 Fair Value**
Fixed rate long-term debt (1) (2)	**$ 12,695**	**$ 12,941**

(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 Contract

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

The Company recognizes a (gain) loss on risk management activities in the statements of earnings related to its natural gas embedded derivative. The (gain) loss is determined by the relative movements in fair value compared to the prior period. For the three months ended December 31, 2025, the Company recognized an unrealized risk management gain of $88 million on the natural gas embedded derivative (year ended December 31, 2025 – unrealized risk management loss of $57 million). At December 31, 2025, the fair value of the embedded derivative was a liability of $57 million.

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 December 31, 2025 are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities.

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

Financial Risk Factors

The Company's financial risks are consistent with those discussed in notes 1, 4 and 19 of the Company's audited consolidated financial statements for the year ended December 31, 2024.

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 December 31, 2025, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

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

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

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

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and, where appropriate, ensuring that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at December 31, 2025, 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 December 31, 2025, 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	$ 1,105	$ —	$ —	$ —
Accrued liabilities	$ 4,255	$ —	$ —	$ —
Long-term debt (1)	$ 441	$ 5,637	$ 2,489	$ 8,140
Other long-term liabilities (2)	$ 381	$ 268	$ 659	$ 1,863
Interest and other financing expense (3)	$ 971	$ 910	$ 1,860	$ 3,678

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

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

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

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 December 31, 2025:

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

(1) The Company's commitment for its 20-year product transportation agreement ending in 2044 on the Trans Mountain Expansion 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) In the fourth quarter of 2025, in connection with the AOSP asset swap (note 4), the Company became the sole contracted shipper on the Corridor pipeline. Previously, the Company recognized a commitment associated with the pipeline, however, following the completion of the AOSP asset swap the contract has been recorded as a lease.

(3) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $1,792 million of interest payable over the 40-year tolling period, ending in 2058 (note 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 Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
(millions of Canadian dollars, unaudited)	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Segmented product sales																
Crude oil and NGLs [1]	**$ 4,417**	$ 4,830	**$ 19,102**	$ 18,740	**$ 89**	$ 102	**$ 325**	$ 467	**$ 33**	$ 67	**$ 164**	$ 434	**$ 4,539**	$ 4,999	**$ 19,591**	$ 19,641
Natural gas [1]	**706**	414	**2,287**	1,415	**2**	3	**13**	7	**—**	8	**30**	42	**708**	425	**2,330**	1,464
Other income and revenue	**18**	16	**92**	6	**—**	—	**—**	4	**—**	1	**1**	4	**18**	17	**93**	14
Total segmented product sales	**5,141**	5,260	**21,481**	20,161	**91**	105	**338**	478	**33**	76	**195**	480	**5,265**	5,441	**22,014**	21,119
Less: royalties	**(551)**	(756)	**(2,529)**	(2,876)	**—**	—	**(1)**	(1)	**(1)**	(4)	**(8)**	(24)	**(552)**	(760)	**(2,538)**	(2,901)
Segmented revenue	**4,590**	4,504	**18,952**	17,285	**91**	105	**337**	477	**32**	72	**187**	456	**4,713**	4,681	**19,476**	18,218
Segmented expenses																
Production	**930**	759	**3,567**	3,249	**118**	121	**469**	440	**21**	23	**79**	109	**1,069**	903	**4,115**	3,798
Blending and feedstock	**951**	1,177	**4,344**	4,643	**—**	—	**—**	—	**—**	—	**—**	—	**951**	1,177	**4,344**	4,643
Transportation	**531**	432	**2,032**	1,541	**4**	1	**10**	10	**—**	1	**—**	1	**535**	434	**2,042**	1,552
Depletion, depreciation and amortization [3]	**1,217**	1,010	**4,582**	3,831	**215**	221	**1,573**	279	**340**	46	**432**	297	**1,772**	1,277	**6,587**	4,407
Asset retirement obligation accretion	**58**	58	**221**	231	**23**	17	**64**	65	**2**	3	**9**	9	**83**	78	**294**	305
Risk management (gain) loss (commodity derivatives)	**(85)**	—	**66**	7	**—**	—	**—**	—	**—**	—	**—**	—	**(85)**	—	**66**	7
Gain on acquisitions, disposition, and remeasurement	**—**	—	**(80)**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(80)**	—
Total segmented expenses	**3,602**	3,436	**14,732**	13,502	**360**	360	**2,116**	794	**363**	73	**520**	416	**4,325**	3,869	**17,368**	14,712
Segmented earnings (loss)	**$ 988**	$ 1,068	**$ 4,220**	$ 3,783	**$ (269)**	$ (255)	**$ (1,779)**	$ (317)	**$ (331)**	$ (1)	**$ (333)**	$ 40	**$ 388**	$ 812	**$ 2,108**	$ 3,506
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management (gain) loss (other)																
Foreign exchange (gain) loss																
Gain from investment																
Total non-segmented expenses																
Earnings before taxes																
Current income tax																
Deferred income tax																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream and Refining				Inter–segment Elimination and Other				Total			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2025	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Segmented product sales																
Crude oil and NGLs [1] [2]	**$ 4,955**	$ 5,362	**$ 20,112**	$ 19,263	**$ 23**	$ 21	**$ 91**	$ 82	**$ 149**	$ (1)	**$ 946**	$ 98	**$ 9,666**	$ 10,381	**$ 40,740**	$ 39,084
Natural gas [1]	**—**	—	**—**	—	**—**	—	**—**	—	**27**	26	**120**	104	**735**	451	**2,450**	1,568
Other income and revenue	**77**	19	**204**	16	**206**	193	**670**	813	**8**	3	**10**	14	**309**	232	**977**	857
Total segmented product sales	**5,032**	5,381	**20,316**	19,279	**229**	214	**761**	895	**184**	28	**1,076**	216	**10,710**	11,064	**44,167**	41,509
Less: royalties	**(549)**	(836)	**(2,867)**	(2,952)	**—**	—	**—**	—	**—**	—	**—**	—	**(1,101)**	(1,596)	**(5,405)**	(5,853)
Segmented revenue	**4,483**	4,545	**17,449**	16,327	**229**	214	**761**	895	**184**	28	**1,076**	216	**9,609**	9,468	**38,762**	35,656
Segmented expenses																
Production	**1,253**	1,019	**4,693**	3,921	**68**	70	**284**	315	**14**	16	**63**	59	**2,404**	2,008	**9,155**	8,093
Blending and feedstock [2]	**597**	741	**2,218**	2,462	**144**	160	**503**	669	**164**	13	**1,006**	157	**1,856**	2,091	**8,071**	7,931
Transportation	**147**	174	**684**	497	**4**	4	**42**	16	**(16)**	(3)	**(17)**	(12)	**670**	609	**2,751**	2,053
Depletion, depreciation and amortization [3]	**762**	621	**2,780**	2,258	**4**	3	**17**	16	**—**	—	**—**	—	**2,538**	1,901	**9,384**	6,681
Asset retirement obligation accretion	**21**	20	**86**	84	**—**	—	**—**	—	**—**	—	**—**	—	**104**	98	**380**	389
Risk management (gain) loss (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(85)**	—	**66**	7
Gain on acquisitions, disposition, and remeasurement	**(4,989)**	—	**(4,989)**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(4,989)**	—	**(5,069)**	—
Total segmented (income) expenses	**(2,209)**	2,575	**5,472**	9,222	**220**	237	**846**	1,016	**162**	26	**1,052**	204	**2,498**	6,707	**24,738**	25,154
Segmented earnings (loss)	**$ 6,692**	$ 1,970	**$ 11,977**	$ 7,105	**$ 9**	$ (23)	**$ (85)**	$ (121)	**$ 22**	$ 2	**$ 24**	$ 12	**$ 7,111**	$ 2,761	**$ 14,024**	$ 10,502
Non-segmented expenses																
Administration													**160**	127	**615**	503
Share-based compensation													**83**	44	**180**	279
Interest and other financing expense													**245**	142	**834**	592
Risk management (gain) loss (other)													**(19)**	142	**(84)**	170
Foreign exchange (gain) loss													**(206)**	720	**(762)**	955
Gain from investment													**—**	—	**—**	(56)
Total non-segmented expenses													**263**	1,175	**783**	2,443
Earnings before taxes													**6,848**	1,586	**13,241**	8,059
Current income tax													**543**	221	**1,911**	1,531
Deferred income tax													**1,002**	227	**510**	422
Net earnings													**$ 5,303**	$ 1,138	**$ 10,820**	$ 6,106

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

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

(3) Includes a $1,462 million non-cash recoverability charge for revisions to abandonment and decommissioning costs in the North Sea, a $269 million non-cash recoverability charge related to the decision to not pursue an extension of the Company's PSC for the Espoir field in Offshore Africa, and a $46 million non-cash derecognition of exploration and evaluation assets related to the decision to not pursue development of Kossipo in Offshore Africa, for the year ended December 31, 2025 (notes 3 and 4).

Capital Expenditures [1]

	Year Ended					
	Dec 31, 2025			Dec 31, 2024		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ 115**	**$ 71**	**$ 186**	$ 406	$ (29)	$ 377
Offshore Africa	**—**	**(46)**	**(46)**	6	(62)	(56)
Oil Sands Mining and Upgrading	**—**	**(13)**	**(13)**	—	(7)	(7)
	115	**12**	**127**	412	(98)	314
Property, plant and equipment						
Exploration and Production						
North America [3]	**4,249**	**(317)**	**3,932**	5,627	(146)	5,481
North Sea	**16**	**—**	**16**	39	295	334
Offshore Africa	**467**	**80**	**547**	197	8	205
	4,732	**(237)**	**4,495**	5,863	157	6,020
Oil Sands Mining and Upgrading [3] [4]	**1,844**	**1,381**	**3,225**	8,104	(134)	7,970
Midstream and Refining	**8**	**—**	**8**	11	—	11
Head Office	**92**	**—**	**92**	41	—	41
	6,676	**1,144**	**7,820**	14,019	23	14,042
	$ 6,791	**$ 1,156**	**$ 7,947**	$ 14,431	$ (75)	$ 14,356

(1) This table provides a reconciliation of capitalized costs, reported in note 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.

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

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

Segmented Assets

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

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 December 31, 2025:	
Interest coverage (times)	
Net earnings [(1)]	16.9x
Adjusted funds flow [(2)]	21.8x

(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

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

Stock Listing

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

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