CANADIAN NATURAL RESOURCES LIMITED
2026 THIRD QUARTER RESULTS

Canadian Natural's President, Scott Stauth, commented on the Company's third quarter results, "The strength of our well-balanced and diverse portfolio, combined with our continued focus on safe, effective and efficient operations, delivered another strong quarter. In Q3/26, we achieved production of approximately 1,217,000 bbl/d of liquids and 2.6 Bcf/d of natural gas, totaling approximately 1,652,000 BOE/d, inclusive of a planned turnaround at Horizon, reflecting the quality of our long life low decline asset base and disciplined operating culture.

Our thermal in situ operations achieved record quarterly production of approximately 300,000 bbl/d, an increase of 25,000 bbl/d from Q3/25 levels, driven by continued strong performance from new pads in Pike and Primrose. In our North American Conventional E&P assets, excluding thermal in situ operations, we also achieved record quarterly liquids production of approximately 358,000 bbl/d, an increase of 49,000 bbl/d from Q3/25 levels driven by accretive acquisitions and strong well performance.

At Horizon, subsequent to quarter end, the team safely and successfully completed the planned turnaround in 28 days, seven days earlier than budgeted, through strong execution, adding significant high value, high margin Synthetic Crude Oil ("SCO") production in Q4/26. Following the turnaround, Oil Sands Mining and Upgrading production has been strong, with current rates averaging approximately 640,000 bbl/d. At Horizon, we continue to build on the success of the 2024 reliability enhancement project that enabled us to move major turnarounds to once every two years from annually, and, combined with verified analysis of key parameters from the 2026 turnaround, we are now targeting to extend turnaround intervals at Horizon to once every three years, further increasing reliability and utilization. As a result, Horizon's three year average production capacity increases by an additional 5,000 bbl/d of high margin SCO, bringing total Oil Sands Mining and Upgrading production capacity up to approximately 597,000 bbl/d.

We are pleased to see the federal government designating the proposed West Coast oil pipeline, now known as Pacific Link, as a project of national interest. In addition, the federal government announced the Productivity Mega Deduction ("PMD"), which is expected to enhance competitiveness and investment in Canada. These measures, combined with the trilateral Memorandum of Understanding ("MOU") between the Oil Sands Alliance, the Government of Alberta and the Federal government, will support future economic growth, add additional egress opportunities, provide a clear pathway to reduce Greenhouse Gas ("GHG") emissions and enhance Canada's competitiveness for investment on a global scale. The next important step in this process is finalizing definitive agreements of the MOU, which will provide clarity on assessing our potential growth projects. If industry and governments are able to successfully complete and finalize the definitive agreements of the MOU, the result will be greater investments in the Canadian economy by the oil and gas industry, creating more jobs for Canadians and greater taxes and royalties for governments."

Canadian Natural's Chief Financial Officer, Victor Darel, added, "We achieved our net debt target of $13 billion in Q3/26, resulting in the Company now targeting to allocate 100% of free cash flow to shareholder returns through share repurchases. To further enhance visibility on share repurchases, effective immediately, the pace of monthly share repurchases is targeted at $800 million per month in both November 2026 and December 2026. As we move into 2027, shareholder returns are expected to remain strong as we now target to allocate 100% of free cash flow to share repurchases, subject to market conditions.

In the first nine months of 2026, we have returned a total of approximately $10.6 billion to shareholders, including $6.8 billion directly through dividends and share buybacks and $3.8 billion indirectly through reductions in net debt.

We delivered strong financial results during the quarter, generating adjusted funds flow of approximately $5.5 billion or $2.68 per share and adjusted net earnings of $3.4 billion or $1.67 per share, including the impact of a planned turnaround at Horizon and lower commodity prices relative to the second quarter, highlighting the quality of our assets and the effectiveness of our operational and capital allocation strategies. Additionally, sulphur pricing continued to strengthen, which contributed pre-tax net revenue of approximately $0.5 billion in Q3/26 and $0.9 billion year to date."

THIRD QUARTER HIGHLIGHTS

- Generated quarterly net earnings of approximately $3.0 billion and quarterly adjusted net earnings from operations of $3.4 billion.
- Generated quarterly adjusted funds flow of approximately $5.5 billion.
  - Captured strong SCO pricing that averaged a US$6.65/bbl premium to WTI in the quarter as a result of strong diesel pricing.
  - Strong sulphur pricing and sulphur production contributed pre-tax net revenue of approximately $0.5 billion[(1)] in Q3/26 and $0.9 billion through the first nine months of 2026.
- The Company achieved its $13 billion net debt target in Q3/26, with 100% of free cash flow now targeted for allocation to share repurchases.
- Returns to shareholders were significant, totaling approximately $5.3 billion in Q3/26.
  - Direct returns to shareholders totaled approximately $2.9 billion in Q3/26, comprised of $1.3 billion in dividends and $1.6 billion in share repurchases.
  - Indirect returns to shareholders, through net debt reductions, totaled approximately $2.4 billion in Q3/26, with net debt decreasing to $12.1 billion as of September 30, 2026, below our $13 billion net debt target.
- Total quarterly production was approximately 1,652,000 BOE/d, an increase of 31,000 BOE/d or 2% from Q3/25 levels.
  - Strong quarterly liquids production was approximately 1,217,000 bbl/d, an increase of 42,000 bbl/d or 4% from Q3/25 levels, inclusive of the planned turnaround at Horizon in Q3/26, which reduced volumes by approximately 75,000 bbl/d for the quarter.
    - Record quarterly thermal in situ production of approximately 300,000 bbl/d, an increase of 25,000 bbl/d or 9% from Q3/25 levels.
      - The two new Steam Assisted Gravity Drainage ("SAGD") pads at Pike 1 continue to exceed expectations, currently producing approximately 46,500 bbl/d at a Steam to Oil Ratio ("SOR") of 1.7x.
    - Record North American Conventional E&P quarterly liquids production of approximately 358,000 bbl/d, an increase of 49,000 bbl/d or 16% from Q3/25 levels.
- Subsequent to quarter end, on October 6, 2026, the team safely and successfully completed the planned turnaround at Horizon in 28 days, seven days earlier than budgeted. This early completion of the turnaround will result in approximately 23,000 bbl/d of additional high margin SCO production in Q4/26 than originally budgeted. Oil Sands Mining and Upgrading production has been strong, with current rates averaging approximately 640,000 bbl/d.

SHAREHOLDER RETURNS

- On November 4, 2026, the Board of Directors approved a quarterly cash dividend of $0.625 per common share, payable on January 5, 2027 to shareholders of record at the close of business on December 15, 2026.
  - This represents an annualized dividend of $2.50 per common share. Our dividend has grown for 26 consecutive years, demonstrating the confidence that the Board has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline reserves and asset base.
- Year to date, up to and including November 4, 2026, the Company has returned a total of approximately $8.9 billion directly to shareholders through $5.1 billion in dividends and $3.8 billion through the repurchase and cancellation of approximately 58.2 million common shares at a weighted average price of $65.85 per share.
  - Included in year to date returns to shareholders is $728 million of share repurchases in October 2026.
- To further enhance visibility, effective immediately, the pace of monthly share repurchases is targeted at $800 million per month in both November 2026 and December 2026.
  - As we move into 2027, shareholder returns are expected to remain strong as we now target to allocate 100% of free cash flow to share repurchases, subject to market conditions.

(1) Item is a component of 'Other income and revenue' in Note 17 Segmented Information in the Company's consolidated financial statements.

HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Net earnings	**$ 2,997**	$ 4,503	$ 600	**$ 8,848**	$ 5,517
Per common share – basic	**$ 1.46**	$ 2.17	$ 0.29	**$ 4.27**	$ 2.64
– diluted	**$ 1.45**	$ 2.15	$ 0.29	**$ 4.24**	$ 2.63
Adjusted net earnings from operations [1]	**$ 3,427**	$ 4,568	$ 1,801	**$ 10,441**	$ 5,733
Per common share – basic [2]	**$ 1.67**	$ 2.20	$ 0.86	**$ 5.04**	$ 2.74
– diluted [2]	**$ 1.65**	$ 2.19	$ 0.86	**$ 5.01**	$ 2.73
Cash flows from operating activities	**$ 7,010**	$ 6,823	$ 3,940	**$ 17,115**	$ 11,338
Adjusted funds flow [1]	**$ 5,522**	$ 6,866	$ 3,920	**$ 16,762**	$ 11,712
Per common share – basic [2]	**$ 2.68**	$ 3.30	$ 1.88	**$ 8.08**	$ 5.59
– diluted [2]	**$ 2.67**	$ 3.28	$ 1.87	**$ 8.04**	$ 5.57
Cash flows used in investing activities	**$ 1,640**	$ 2,468	$ 2,234	**$ 6,057**	$ 5,487
Net capital expenditures [1]	**$ 1,883**	$ 2,405	$ 2,124	**$ 6,316**	$ 5,342
Net capital expenditures [1], excluding net acquisitions	**$ 1,885**	$ 1,643	$ 1,318	**$ 4,783**	$ 4,312
Abandonment expenditures	**$ 248**	$ 182	$ 189	**$ 677**	$ 570
Daily production, before royalties					
Natural gas (MMcf/d)	**2,607**	2,567	2,668	**2,615**	2,510
Crude oil and NGLs (bbl/d)	**1,217,178**	1,248,889	1,175,604	**1,221,452**	1,122,859
Equivalent production (BOE/d) [3]	**1,651,720**	1,676,754	1,620,261	**1,657,243**	1,541,127

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

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

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

OPERATIONS REVIEW

North America Oil Sands Mining and Upgrading

	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Synthetic crude oil production (bbl/d) [(1)(2)]	**543,089**	624,754	581,136	**585,099**	546,635

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

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

- Oil Sands Mining and Upgrading production averaged 543,089 bbl/d of SCO in Q3/26, a decrease of 7% from Q3/25 levels, reflecting the planned turnaround at Horizon, partially offset by the additional working interest acquired in the Albian mines in December 2025.
  - The Company's Oil Sands Mining and Upgrading operating costs are industry leading, averaging $25.80/bbl (US$18.44/bbl) of SCO in Q3/26. Operating costs on a per barrel basis primarily reflect lower production as a result of the turnaround at Horizon.
- Subsequent to quarter end, on October 6, 2026, the Company safely and successfully completed the planned turnaround at Horizon in 28 days, seven days earlier than budgeted. This early completion of the turnaround will result in approximately 23,000 bbl/d of additional high margin SCO production in Q4/26 than originally budgeted. Following the turnaround, Oil Sands Mining and Upgrading production has been strong, with current rates averaging approximately 640,000 bbl/d.
  - At Horizon, we continue to build on the success of the 2024 reliability enhancement project that enabled us to move major turnarounds to once every two years from annually, and, combined with verified analysis of key parameters from the 2026 turnaround, we are now targeting to extend turnaround intervals at Horizon to once every three years, further increasing reliability and utilization.
    - As a result of moving to a three year turnaround cycle, Horizon's average production capacity over the three year period increases by an additional 5,000 bbl/d of high margin SCO barrels, bringing total Oil Sands Mining and Upgrading production capacity up to approximately 597,000 bbl/d.
- The Company's Naphtha Recovery Unit Tailings Treatment ("NRUTT") project at Horizon remains on track with capital on budget and targeted incremental annual production of approximately 6,300 bbl/d of SCO, following mechanical completion in Q3/27.

North America Exploration and Production

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Bitumen production (bbl/d)	**299,632**	275,607	274,752	**283,396**	278,046
Net bitumen wells drilled	**45**	38	11	**114**	53

- Record thermal in situ production of 299,632 bbl/d was achieved in Q3/26, an increase of approximately 25,000 bbl/d or 9% from Q3/25 levels, reflecting strong production from the recently added SAGD pads and the new Cyclic Steam Stimulation ("CSS") pad at Primrose that came on production in July 2026.
  - Jackfish achieved record quarterly production of 143,039 bbl/d in Q3/26, exceeding its facility nameplate capacity by approximately 23,000 bbl/d as a result of strong performance from the Pike 1 pads.
    - The two new SAGD pads at Pike 1 continue to exceed expectations, currently producing approximately 46,500 bbl/d at a SOR of 1.7x. The Pike 1 SAGD pads are top tier in industry, driven by high-quality resource and continuous improvement in technology and execution.
  - Thermal in situ operating costs averaged $10.19/bbl (US$7.28/bbl) in Q3/26, a decrease of approximately 2% compared to $10.35/bbl in Q3/25, reflecting higher production, partially offset by higher energy costs.

- Canadian Natural has decades of robust, capital efficient drill to fill opportunities across its long life low decline thermal in situ assets. The Company is on track with its 2026 budget, with the following pad additions:
  - At Primrose, two Cyclic Steam Stimulation ("CSS") pads are targeted to come on production in Q1/27 and Q2/27.
  - At Kirby, the Company is drilling a SAGD pad, which is targeted to come on production in Q3/27.
- 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 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.
  - As a result of continued strong production performance from new wells at the Kirby South pilot, the Company is targeting to begin solvent injection using diluent in the first half of 2027.

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Crude oil and NGLs production (bbl/d)	**358,484**	338,138	309,873	**341,848**	285,931
Net crude oil wells drilled	**108**	80	78	**271**	192

- Record quarterly North America E&P liquids production, excluding thermal in situ operations, of 358,484 bbl/d was achieved in Q3/26, an increase of approximately 49,000 bbl/d or 16% from Q3/25 levels. This record reflects accretive Charlie Lake light crude oil acquisitions and strong organic growth in heavy crude oil, light crude oil and NGLs.
  - Strong primary heavy crude oil production averaged 95,621 bbl/d in Q3/26, an increase of 9% from Q3/25 levels, reflecting growth in our quick payout, high return multilateral wells.
    - Canadian Natural's highly successful multilateral drilling program, driven by continuous improvement in execution and technology advancements, continues to unlock opportunities on our 3 million net acres of high quality, multizone land throughout our primary heavy crude oil assets.
    - Operating costs in the Company's primary heavy crude oil operations averaged $18.02/bbl (US$12.88/bbl) in Q3/26, an increase from $16.46/bbl in Q3/25, reflecting increased weather related road maintenance and higher diesel costs.
  - In the Company's Pelican Lake polymer flood area, production averaged 45,514 bbl/d in Q3/26, an increase of 8% from Q3/25 levels, reflecting strong results from Driftwood and the long life low decline nature of these assets.
    - Operating costs at Pelican Lake averaged $10.45/bbl (US$7.47/bbl) in Q3/26, an increase from $9.00/bbl in Q3/25, reflecting increased trucked production from Driftwood.
  - Record quarterly production of 217,349 bbl/d was achieved in North America light crude oil and NGLs in Q3/26, an increase of approximately 37,000 bbl/d or 21% from Q3/25 levels, primarily reflecting accretive acquisitions and strong drilling results.
    - Operating costs in the Company's North America light crude oil and NGLs operations averaged $12.85/bbl (US$9.18/bbl) in Q3/26, comparable to Q3/25 levels.

North America Natural Gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Natural gas production (MMcf/d)	**2,602**	2,563	2,658	**2,611**	2,498
Net natural gas wells drilled	**11**	23	17	**58**	58

- North America natural gas production averaged 2,602 MMcf/d in Q3/26, a decrease of 2% from Q3/25 levels, reflecting natural field declines partially offset by accretive acquisitions completed in 2026 and strong liquids-rich natural gas drilling results. North America natural gas operating costs averaged $1.14/Mcf in Q3/26.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Crude oil production (bbl/d)	**15,973**	10,390	9,843	**11,110**	12,247
Natural gas production (MMcf/d)	**5**	4	10	**4**	12

- International E&P crude oil production volumes averaged 15,973 bbl/d in Q3/26, an increase of 62% compared to Q3/25 levels. The increase reflects the return of production at Baobab in Offshore Africa in June 2026 following completion of the refurbishment of the floating production storage and offloading ("FPSO") vessel, partially offset by the planned North Sea abandonments conducted as part of the previously announced decommissioning activities.
  - At Baobab, the Company commenced its Phase 5 drilling program in September 2026 and is targeting to complete the drilling program in Q3/27.

Drilling Activity

	Three Months Ended				Nine Months Ended			
	September 30, 2026		September 30, 2025		**September 30, 2026**		September 30, 2025	
(number of wells)	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Crude oil [(1)]	**159**	**153**	92	89	**398**	**385**	253	245
Natural gas	**15**	**11**	23	17	**74**	**58**	73	58
Subtotal	**174**	**164**	115	106	**472**	**443**	326	303
Stratigraphic test / service wells	**12**	**12**	3	3	**573**	**573**	516	493
Total	**186**	**176**	118	109	**1,045**	**1,016**	842	796

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 443 net crude oil and natural gas wells in the first nine months of 2026, 140 more than in the comparable period in 2025.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Benchmark Commodity Prices					
WTI benchmark price (US$/bbl) [1]	**$ 85.68**	$ 92.85	$ 64.95	**$ 83.62**	$ 66.67
WCS heavy differential (discount) to WTI (US$/bbl) [1]	**$ (13.86)**	$ (14.62)	$ (10.36)	**$ (14.20)**	$ (11.07)
WCS heavy differential as a percentage of WTI (%) [1]	**16%**	16%	16%	**17%**	17%
Condensate benchmark price (US$/bbl)	**$ 82.22**	$ 95.59	$ 63.12	**$ 83.19**	$ 65.45
SCO price (US$/bbl) [1]	**$ 92.33**	$ 101.22	$ 66.26	**$ 88.51**	$ 66.66
SCO premium (discount) to WTI (US$/bbl) [1]	**$ 6.65**	$ 8.37	$ 1.31	**$ 4.89**	$ (0.01)
AECO benchmark price (C$/GJ)	**$ 1.47**	$ 1.43	$ 0.94	**$ 1.75**	$ 1.61
Realized Prices					
Exploration & Production liquids realized price (C$/bbl) [2][3][4][5]	**$ 95.93**	$ 105.11	$ 72.57	**$ 92.62**	$ 74.06
SCO realized price (C$/bbl) [1][3][4][5]	**$ 114.56**	$ 125.78	$ 87.85	**$ 110.26**	$ 90.45
Natural gas realized price (C$/Mcf) [4]	**$ 2.09**	$ 2.05	$ 1.49	**$ 2.49**	$ 2.37

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

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

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

(4) Excludes risk management activities.

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

- Canadian Natural has a balanced and diverse product mix of SCO, light crude oil, NGLs, heavy crude oil, bitumen and natural gas, complemented with a balanced and diverse marketing strategy.
  - Approximately 776,000 bbl/d or 64% of total liquids production in Q3/26 consisted of SCO, light crude oil and NGLs.
  - The SCO price premium to WTI was strong in Q3/26, averaging US$6.65/bbl, primarily driven by strong diesel refining margins and planned seasonal maintenance in the Western Canadian Sedimentary Basin ("WCSB").
    - Current SCO annual average strip pricing in 2026 represents a premium to WTI of approximately US$5.56/bbl.
- Canadian Natural has increased its committed volumes to 177,750 bbl/d on the Trans Mountain Expansion ("TMX") pipeline, bringing total contracted crude oil export transportation capacity up to 265,250 bbl/d to Canada's west coast and to the United States Gulf Coast, representing approximately 22% 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 84,730 bbl/d in Q3/26.
- Canadian Natural maintains a diversified natural gas marketing strategy. In 2026, the Company is targeting to consume the equivalency of approximately 34% of its forecasted natural gas production in its Oil Sands Mining and Upgrading and thermal operations, with approximately 33% targeted to be sold at AECO/Station 2 pricing, and approximately 33% targeted to be exported to other North American and international markets capturing higher natural gas prices, maximizing value.
- Canadian Natural has a long-term natural gas supply agreement with Cheniere Marketing, LLC. ("Cheniere") as part of the Sabine Pass Liquefaction Expansion Project where the Company has agreed to sell 140,000 MMBtu/d of natural gas to Cheniere for a term of 15 years, with delivery anticipated to begin in 2030.
  - Under the terms of the agreement, Canadian Natural will deliver natural gas to Cheniere in Chicago and receive a Japan Korea Marker ("JKM") index price less deductions for transportation and liquefaction.

ADVISORY

Special Note Regarding Non-GAAP and Other Financial Measures

This document includes references to non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure ("NI 52-112"). These financial measures are used by the Company to evaluate its financial performance, financial position, and cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS Accounting Standards and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this document and the Company's MD&A and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below as well as in the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A for the three and nine months ended September 30, 2026 dated November 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. Working capital movements, foreign exchange rate changes and other factors may result in shareholder returns varying from free cash flow generated in a particular period. Accordingly, the timing and allocation of shareholder returns may be accelerated, deferred or reallocated between periods at management's discretion.

As of September 30, 2026, the Company's net debt was below its $13 billion net debt target, resulting in the Company now targeting to allocate 100% of free cash flow to shareholder returns through share repurchases.

The Company's free cash flow for the three months ended September 30, 2026 and comparable periods is shown below:

	Three Months Ended		
($ millions)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025
Adjusted funds flow [(1)]	**$ 5,522**	$ 6,866	$ 3,920
Less: Dividends on common shares	**1,294**	1,304	1,228
Net capital expenditures [(1)]	**1,883**	2,405	2,124
Abandonment expenditures	**248**	182	189
Free cash flow	**$ 2,097**	$ 2,975	$ 379

(1) Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A for the three and nine months ended September 30, 2026 dated November 4, 2026.

Long-term Debt, net

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

($ millions)	**Sep 30 2026**	Jun 30 2026	Dec 31 2025	Sep 30 2025
Long-term debt	**$ 16,633**	$ 17,144	$ 16,617	$ 17,268
Less: cash and cash equivalents	**4,516**	2,618	673	113
Long-term debt, net	**$ 12,117**	$ 14,526	$ 15,944	$ 17,155

Breakeven WTI Price

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

Capital Budget

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

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

Capital Efficiency

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

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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, forecasted or anticipated production volumes, royalties, production expenses, capital expenditures, forecasted and anticipated abandonment expenditures, income tax expenses, and other targets provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, including the strength of the Company's balance sheet, the sources and adequacy of the Company's liquidity, and the flexibility of the Company's capital structure, constitute forward-looking statements. Disclosure of plans relating to, and expected results of existing and future developments, including, without limitation, those in relation to: the Company's assets at Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), the Primrose thermal oil projects ("Primrose"), the Pelican Lake water and polymer flood projects ("Pelican Lake"), the Kirby thermal oil sands project ("Kirby"), the Jackfish thermal oil sands project ("Jackfish"), the Pike thermal oil sands project ("Pike"), 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 crude oil, bitumen, 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/or deployment of technology and technological innovations (including artificial intelligence ("AI")) and the timely and effective implementation thereof; 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, bitumen, 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 and in Ukraine, the restriction or disruption of global trade routes, the impact of changes to US economic policy, increased inflation, and the risk of decreased economic activity resulting from a global recession) which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil, bitumen, 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 timing, impact, and success of the implementation of the Memorandum of Understanding ("MOU") entered into between the Government of Canada and the Government of Alberta in November 2025 and the trilateral Memorandum of Understanding ("trilateral MOU") entered into between the Oil Sands Alliance, the Government of Alberta, and the Government of Canada in July 2026, including the execution of definitive agreements and satisfaction of other regulatory, financial and other conditions contemplated thereunder; 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 or AI-related incidents; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; the impact of AI on the Company's business operations; the impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling, and other equipment; ability of the Company to complete capital programs; the Company's ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting, or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in the mining, extracting, or upgrading of the Company's bitumen products; availability and cost of financing; the Company's success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, bitumen, natural gas and NGLs not currently

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

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

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

Special Note Regarding Non-GAAP and Other Financial Measures

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

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

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

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the Company's unaudited interim consolidated financial statements (the "financial statements") for the three and nine months ended September 30, 2026, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2025. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three and nine months ended September 30, 2026 and this MD&A have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("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 and nine months ended September 30, 2026 in relation to the comparable periods in 2025 and the second quarter of 2026. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2025, is available on SEDAR+ at www.sedarplus.ca, and on EDGAR at www.sec.gov. Information in such Annual Information Form and on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated November 4, 2026.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Product sales [1]	**$ 15,643**	$ 17,214	$ 11,070	**$ 45,261**	$ 33,457
Crude oil and NGLs	**$ 14,269**	$ 16,067	$ 10,468	**$ 41,450**	$ 31,074
Natural gas	**$ 531**	$ 503	$ 399	**$ 1,866**	$ 1,715
Net earnings	**$ 2,997**	$ 4,503	$ 600	**$ 8,848**	$ 5,517
Per common share – basic	**$ 1.46**	$ 2.17	$ 0.29	**$ 4.27**	$ 2.64
– diluted	**$ 1.45**	$ 2.15	$ 0.29	**$ 4.24**	$ 2.63
Adjusted net earnings from operations [2]	**$ 3,427**	$ 4,568	$ 1,801	**$ 10,441**	$ 5,733
Per common share – basic [3]	**$ 1.67**	$ 2.20	$ 0.86	**$ 5.04**	$ 2.74
– diluted [3]	**$ 1.65**	$ 2.19	$ 0.86	**$ 5.01**	$ 2.73
Cash flows from operating activities	**$ 7,010**	$ 6,823	$ 3,940	**$ 17,115**	$ 11,338
Adjusted funds flow [2]	**$ 5,522**	$ 6,866	$ 3,920	**$ 16,762**	$ 11,712
Per common share – basic [3]	**$ 2.68**	$ 3.30	$ 1.88	**$ 8.08**	$ 5.59
– diluted [3]	**$ 2.67**	$ 3.28	$ 1.87	**$ 8.04**	$ 5.57
Cash flows used in investing activities	**$ 1,640**	$ 2,468	$ 2,234	**$ 6,057**	$ 5,487
Net capital expenditures [2]	**$ 1,883**	$ 2,405	$ 2,124	**$ 6,316**	$ 5,342
Abandonment expenditures	**$ 248**	$ 182	$ 189	**$ 677**	$ 570

(1) Further details related to product sales are disclosed in note 17 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 nine months ended September 30, 2026 were $8,848 million compared with $5,517 million for the nine months ended September 30, 2025. Net earnings for the nine months ended September 30, 2026 included non-operating losses, net of tax, of $1,593 million compared with non-operating losses of $216 million for the nine months ended September 30, 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 acquisition in 2025, and a recoverability charge related to the increase in estimated future abandonment costs for the Ninian field and T-Block assets in the North Sea in the third quarter of 2025. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2026 were $10,441 million compared with $5,733 million for the nine months ended September 30, 2025. Further details related to the movements in adjusted net earnings from operations are discussed in the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Net earnings for the third quarter of 2026 were $2,997 million compared with $600 million for the third quarter of 2025 and $4,503 million for the second quarter of 2026. Net earnings for the third quarter of 2026 included non-operating losses, net of tax, of $430 million compared with non-operating losses of $1,201 million for the third quarter of 2025 and non-operating losses of $65 million for the second quarter of 2026 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on financing activities, and a recoverability charge related to the increase in estimated future abandonment costs for the Ninian field and T-Block assets in the North Sea in the third quarter of 2025. Excluding these items, adjusted net earnings from operations for the third quarter of 2026 were $3,427 million compared with $1,801 million for the third quarter of 2025 and $4,568 million for the second quarter of 2026. Further details related to the movements in adjusted net earnings from operations are discussed in the 'Non-GAAP and Other Financial Measures' section of this MD&A.

The increase in net earnings and adjusted net earnings from operations for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected:

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

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

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

partially offset by:

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

The decrease in net earnings and adjusted net earnings from operations for the third quarter of 2026 from the second quarter of 2026 primarily reflected:

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

partially offset by:

- higher crude oil and NGLs sales volumes in the North America Exploration and Production segment.

The impacts of depletion, depreciation and amortization, share-based compensation, risk management activities, foreign exchange loss (gain), and the gain on acquisition in 2025 also contributed to the movements in net earnings from the comparable periods. These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the nine months ended September 30, 2026 were $17,115 million compared with $11,338 million for the nine months ended September 30, 2025. Cash flows from operating activities for the third quarter of 2026 were $7,010 million compared with $3,940 million for the third quarter of 2025 and $6,823 million for the second quarter of 2026. 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 nine months ended September 30, 2026 was $16,762 million compared with $11,712 million for the nine months ended September 30, 2025. Adjusted funds flow for the third quarter of 2026 was $5,522 million compared with $3,920 million for the third quarter of 2025 and $6,866 million for the second quarter of 2026. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above related to the fluctuations in cash flows from operating activities, excluding the impact of the net change in non-cash working capital, abandonment expenditures, and movements in other long-term assets, including the unamortized cost of contributions to the Company's employee bonus program, interest on Petroleum Revenue Tax ("PRT") recoveries, and prepaid cost of service tolls. Further details related to the movements in adjusted funds flow are discussed in the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Production Volumes

Crude oil and NGLs production before royalties for the third quarter of 2026 of 1,217,178 bbl/d increased 4% from 1,175,604 bbl/d for the third quarter of 2025 and decreased 3% from 1,248,889 bbl/d for the second quarter of 2026. Natural gas production before royalties for the third quarter of 2026 of 2,607 MMcf/d was comparable with 2,668 MMcf/d for the third quarter of 2025 and 2,567 MMcf/d for the second quarter of 2026. Total production before royalties for the third quarter of 2026 of 1,651,720 BOE/d was comparable with 1,620,261 BOE/d for the third quarter of 2025 and 1,676,754 BOE/d for the second quarter of 2026. Crude oil and NGLs and natural gas production volumes are discussed in detail in the 'Daily Production, before royalties' section of this MD&A.

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

Product Prices

In the Company's Exploration and Production segments, the realized crude oil and NGLs price averaged $95.93 per bbl for the third quarter of 2026, an increase of 32% from $72.57 per bbl for the third quarter of 2025 and a decrease of 9% from $105.11 per bbl for the second quarter of 2026. The realized natural gas price increased 40% to average $2.09 per Mcf for the third quarter of 2026 from $1.49 per Mcf for the third quarter of 2025 and was comparable with $2.05 per Mcf for the second quarter of 2026. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price increased 30% to average $114.56 per bbl for the third quarter of 2026 from $87.85 per bbl for the third quarter of 2025 and decreased 9% from $125.78 per bbl for the second quarter of 2026. The Company's realized product pricing is reflective of the prevailing benchmark pricing. Crude oil and NGLs and natural gas prices are discussed in detail in the 'Business Environment', 'Realized Product Prices – Exploration and Production', and 'Realized Product Prices, Royalties and Transportation – Oil Sands Mining and Upgrading' sections of this MD&A.

Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense[(1)] averaged $13.76 per bbl for the third quarter of 2026, an increase of 4% from $13.18 per bbl for the third quarter of 2025 and a decrease of 8% from $14.99 per bbl for the second quarter of 2026. Natural gas production expense[(1)] averaged $1.18 per Mcf for the third quarter of 2026, comparable with $1.16 per Mcf for the third quarter of 2025 and a decrease of 8% from $1.28 per Mcf for the second quarter of 2026. In the Oil Sands Mining and Upgrading segment, production expense[(1)] averaged $25.80 per bbl for the third quarter of 2026, an increase of 21% from $21.29 per bbl for the third quarter of 2025 and an increase of 16% from $22.19 per bbl for the second quarter of 2026. Crude oil and NGLs and natural gas production expense is discussed in detail in the 'Production Expense – Exploration and Production' and 'Production Expense – Oil Sands Mining and Upgrading' sections of this MD&A.

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)	**Sep 30 2026**	Jun 30 2026	Mar 31 2026	Dec 31 2025
Product sales [(1)]	**$ 15,643**	$ 17,214	$ 12,404	$ 10,710
Crude oil and NGLs	**$ 14,269**	$ 16,067	$ 11,114	$ 9,666
Natural gas	**$ 531**	$ 503	$ 832	$ 735
Net earnings	**$ 2,997**	$ 4,503	$ 1,348	$ 5,303
Net earnings per common share				
– basic	**$ 1.46**	$ 2.17	$ 0.65	$ 2.55
– diluted	**$ 1.45**	$ 2.15	$ 0.64	$ 2.54

($ millions, except per common share amounts)	Sep 30 2025	Jun 30 2025	Mar 31 2025	Dec 31 2024
Product sales [(1)]	$ 11,070	$ 9,675	$ 12,712	$ 11,064
Crude oil and NGLs	$ 10,468	$ 8,874	$ 11,732	$ 10,381
Natural gas	$ 399	$ 600	$ 716	$ 451
Net earnings	$ 600	$ 2,459	$ 2,458	$ 1,138
Net earnings per common share				
– basic	$ 0.29	$ 1.17	$ 1.17	$ 0.54
– diluted	$ 0.29	$ 1.17	$ 1.17	$ 0.54

(1) Further details related to product sales for the three months ended September 30, 2026 and 2025 are disclosed in note 17 to the financial statements.

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

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

- **Crude oil pricing** – Fluctuations in global supply/demand including crude oil production levels from OPEC+ and its impact on world supply; the impact of geopolitical and market uncertainties (including those due to the conflicts in the Middle East and in Ukraine, the restriction or disruption of global trade routes, and the impacts of ongoing tariff and trade uncertainty) on worldwide benchmark pricing; the impact of shale oil production in North America; market egress including the Trans Mountain Expansion ("TMX") pipeline; the impact of increased availability of heavy crude oil at the US Gulf Coast; 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, including the ramp-up of processing capacity at LNG Canada; 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; 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, which returned to service during the second quarter of 2026.
- **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; natural field declines; the impact of seasonal conditions; wildfires; and maintenance activities 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 compliance costs; fluctuating energy costs; inflationary cost pressures; cost optimizations across all segments; turnarounds in the Oil Sands Mining and Upgrading segment; and maintenance activities.
- **Depletion, depreciation and amortization expense** – Fluctuations due to changes in sales volumes; timing of acquisitions; proved reserves; asset retirement obligations; finding and development costs associated with crude oil and natural gas exploration; estimated future costs to develop the Company's proved undeveloped reserves; fluctuations in International sales volumes subject to higher depletion rates; the impact of turnarounds in the Oil Sands Mining and Upgrading segment; the impact on the depletable base resulting from the gain recognized on the AOSP mine assets in the fourth quarter of 2025; and recoverability charges related to the North Sea and Offshore Africa.
- **Share-based compensation** – Fluctuations due to the measurement of fair market value of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market, and subsequent settlement of the Company's risk management activities.
- **Interest expense** – Fluctuations due to changing long-term debt levels and lease liabilities; the impact of movements in benchmark interest rates on outstanding floating rate long-term debt; and interest on PRT recoveries.
- **Foreign exchange** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt and working capital.
- **Gain on acquisitions, disposition, and remeasurement** – Fluctuations due to gain on acquisitions, representing the excess of the fair value of the net assets acquired compared to total purchase consideration and previously held interests. A gain on remeasurement to fair value of the Company's pre-existing 90% interest in the AOSP mines and a gain on disposition of the 10% interest in the non-operated Scotford Upgrader ("Scotford") and the Quest Carbon Capture and Storage facility ("Quest") disposed of as part of the AOSP asset swap in the fourth quarter of 2025.

BUSINESS ENVIRONMENT

Global crude oil benchmark pricing decreased in the third quarter of 2026 as uncertainty over crude oil supply disruptions, including market expectations of a partial recovery in Middle East crude oil supply combined with weaker global demand reduced crude oil pricing early in the quarter. This decrease was partially offset by escalating geopolitical tensions toward the end of the third quarter, as global crude oil supply disruptions persisted following renewed conflict in the Middle East. Crude oil pricing is expected to remain volatile in the near-term amid ongoing geopolitical uncertainty. Although pricing may stabilize as supply recovers and supply-demand fundamentals reassert themselves, further conflict or disruptions to global crude oil supply could materially impact pricing through the remainder of 2026.

Natural gas benchmark pricing remained relatively consistent in the third quarter of 2026, as higher US production and planned LNG maintenance activities in the US Gulf Coast were offset by increased summer electricity demand. In Canada, increased demand from higher processing capacity at LNG Canada supported AECO benchmark pricing, partially offsetting elevated Western Canadian Sedimentary Basin ("WCSB") production. Demand from LNG Canada is expected to continue supporting AECO pricing as the facility operates toward full processing capacity.

Trilateral Memorandum of Understanding

In July 2026, the Oil Sands Alliance, the Government of Alberta, and the Government of Canada entered into a trilateral MOU. The trilateral MOU outlines a potential regulatory and fiscal framework intended to support the competitiveness of Canada's energy industry. Implementation of the framework contemplated by the trilateral MOU remains subject to definitive agreements and regulatory approvals.

Benchmark Commodity Prices

	Three Months Ended			Nine Months Ended	
(Average for the period)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
WTI benchmark price (US$/bbl)	**$ 85.68**	$ 92.85	$ 64.95	**$ 83.62**	$ 66.67
Dated Brent benchmark price (US$/bbl)	**$ 96.79**	$ 104.51	$ 69.08	**$ 94.13**	$ 70.82
WCS Heavy Differential from WTI (US$/bbl)	**$ 13.86**	$ 14.62	$ 10.36	**$ 14.20**	$ 11.07
SCO price (US$/bbl)	**$ 92.33**	$ 101.22	$ 66.26	**$ 88.51**	$ 66.66
Condensate benchmark price (US$/bbl)	**$ 82.22**	$ 95.59	$ 63.12	**$ 83.19**	$ 65.45
NYMEX benchmark price (US$/MMBtu)	**$ 2.96**	$ 2.89	$ 3.07	**$ 3.60**	$ 3.39
AECO benchmark price (C$/GJ)	**$ 1.47**	$ 1.43	$ 0.94	**$ 1.75**	$ 1.61
US/Canadian dollar average exchange rate (US$)	**$ 0.7147**	$ 0.7225	$ 0.7262	**$ 0.7220**	$ 0.7150

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

Crude Oil

Crude oil sales contracts in North America are typically based on WTI benchmark pricing. WTI averaged US$83.62 per bbl for the nine months ended September 30, 2026, an increase of 25% from US$66.67 per bbl for the nine months ended September 30, 2025. WTI averaged US$85.68 per bbl for the third quarter of 2026, an increase of 32% from US$64.95 per bbl for the third quarter of 2025 and a decrease of 8% from US$92.85 per bbl for the second quarter of 2026.

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$94.13 per bbl for the nine months ended September 30, 2026, an increase of 33% from US$70.82 per bbl for the nine months ended September 30, 2025. Brent averaged US$96.79 per bbl for the third quarter of 2026, an increase of 40% from US$69.08 per bbl for the third quarter of 2025 and a decrease of 7% from US$104.51 per bbl for the second quarter of 2026.

The increase in WTI and Brent benchmark pricing for the three and nine months ended September 30, 2026 from the comparable periods in 2025 primarily reflected continued conflict in the Middle East and the resulting global supply disruptions, partially offset by releases of global crude oil inventories in the second and third quarters of 2026 and weaker demand. The decrease in WTI and Brent benchmark pricing for the third quarter of 2026 from the second quarter of 2026 primarily reflected uncertainty over global crude oil supply disruptions, including market expectations of a partial recovery of Middle East crude oil supply early in the third quarter, partially offset by escalating geopolitical tensions toward the end of the quarter.

The WCS Heavy Differential averaged US$14.20 per bbl for the nine months ended September 30, 2026, compared with US$11.07 per bbl for the nine months ended September 30, 2025. The WCS Heavy Differential averaged US$13.86 per bbl for the third quarter of 2026, compared with US$10.36 per bbl for the third quarter of 2025 and US$14.62 per bbl for the second quarter of 2026. The widening of the WCS Heavy Differential for the three and nine months ended September 30, 2026 from the comparable periods in 2025 primarily reflected strong WTI benchmark pricing and increased heavy crude oil availability at the US Gulf Coast, partially offset by a tightening of the sour crude oil market due to Middle East supply disruptions. The narrowing of the WCS Heavy Differential for the third quarter of 2026 from the second quarter of 2026 primarily reflected strong seasonal demand and high refinery utilization in the third quarter.

The SCO price averaged US$88.51 per bbl for the nine months ended September 30, 2026, an increase of 33% from US$66.66 per bbl for the nine months ended September 30, 2025. SCO pricing averaged US$92.33 per bbl for the third quarter of 2026, an increase of 39% from US$66.26 per bbl for the third quarter of 2025 and a decrease of 9% from US$101.22 per bbl for the second quarter of 2026. The increase in SCO pricing for the three and nine months ended September 30, 2026 from the comparable periods in 2025 primarily reflected higher WTI benchmark pricing, planned seasonal maintenance, and stronger refinery demand amid tighter refined product markets due to Middle East supply disruptions. The decrease in SCO pricing for the third quarter of 2026 from the second quarter of 2026 primarily reflected lower WTI benchmark pricing, partially offset by strong diesel refining margins and planned seasonal maintenance in the WCSB.

Natural Gas

NYMEX benchmark pricing averaged US$3.60 per MMBtu for the nine months ended September 30, 2026, an increase of 6% from US$3.39 per MMBtu for the nine months ended September 30, 2025. NYMEX benchmark pricing averaged US$2.96 per MMBtu for the third quarter of 2026, a decrease of 4% from US$3.07 per MMBtu for the third quarter of 2025 and comparable with US$2.89 per MMBtu for the second quarter of 2026. The increase in NYMEX natural gas pricing for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected strong LNG demand and exports out of the US Gulf Coast, and weather-related outages in the Eastern US following severe winter storms early in the first quarter of 2026. The decrease in NYMEX natural gas pricing for the third quarter of 2026 from the third quarter of 2025 primarily reflected higher US production combined with planned LNG maintenance activities in the US Gulf Coast in the third quarter of 2026, partially offset by increased summer electricity demand amid record average temperatures in the US, and increased LNG export capacity.

AECO benchmark pricing averaged $1.75 per GJ for the nine months ended September 30, 2026, an increase of 9% from $1.61 per GJ for the nine months ended September 30, 2025. AECO benchmark pricing averaged $1.47 per GJ for the third quarter of 2026, an increase of 56% from $0.94 per GJ for the third quarter of 2025 and comparable with $1.43 per GJ for the second quarter of 2026. The increase in AECO natural gas pricing for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected higher NYMEX benchmark pricing, and increased demand from the continued ramp-up of LNG Canada. The increase in AECO natural gas pricing for the third quarter of 2026 from the third quarter of 2025 primarily reflected higher processing capacity at LNG Canada in 2026, partially offset by elevated WCSB production.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**658,116**	613,745	584,625	**625,243**	563,977
North America – Oil Sands Mining and Upgrading [1]	**543,089**	624,754	581,136	**585,099**	546,635
International – Exploration and Production					
North Sea	**5,943**	6,589	7,045	**5,791**	8,755
Offshore Africa	**10,030**	3,801	2,798	**5,319**	3,492
Total International [2]	**15,973**	10,390	9,843	**11,110**	12,247
Total Crude oil and NGLs	**1,217,178**	1,248,889	1,175,604	**1,221,452**	1,122,859
Natural gas (MMcf/d) [3]					
North America	**2,602**	2,563	2,658	**2,611**	2,498
International					
North Sea	**2**	2	2	**2**	3
Offshore Africa	**3**	2	8	**2**	9
Total International	**5**	4	10	**4**	12
Total Natural gas	**2,607**	2,567	2,668	**2,615**	2,510
Total Barrels of oil equivalent (BOE/d)	**1,651,720**	1,676,754	1,620,261	**1,657,243**	1,541,127
Product mix					
Light and medium crude oil and NGLs	**14%**	13%	12%	**13%**	11%
Pelican Lake heavy crude oil	**3%**	3%	3%	**3%**	3%
Primary heavy crude oil	**6%**	5%	5%	**6%**	6%
Thermal bitumen	**18%**	16%	17%	**17%**	18%
Synthetic crude oil [1]	**33%**	37%	36%	**35%**	35%
Natural gas	**26%**	26%	27%	**26%**	27%
Percentage of product sales [1] [4] [5]					
Crude oil and NGLs	**96%**	97%	96%	**95%**	94%
Natural gas	**4%**	3%	4%	**5%**	6%

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

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

(3) Natural gas production volumes approximate sales volumes.

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

(5) Excluding Midstream and Refining revenue.

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**498,781**	496,377	479,660	**497,514**	469,188
North America – Oil Sands Mining and Upgrading [(1)]	**405,370**	515,113	473,188	**470,131**	450,130
International – Exploration and Production					
North Sea	**5,930**	6,579	7,017	**5,782**	8,735
Offshore Africa	**9,616**	3,626	2,669	**5,122**	3,338
Total International	**15,546**	10,205	9,686	**10,904**	12,073
Total Crude oil and NGLs	**919,697**	1,021,695	962,534	**978,549**	931,391
Natural gas (MMcf/d)					
North America	**2,527**	2,476	2,615	**2,516**	2,430
International					
North Sea	**2**	2	2	**2**	3
Offshore Africa	**3**	2	8	**2**	8
Total International	**5**	4	10	**4**	11
Total Natural gas	**2,532**	2,480	2,625	**2,520**	2,441
Total Barrels of oil equivalent (BOE/d)	**1,341,759**	1,435,078	1,399,968	**1,398,488**	1,338,293

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

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

Crude oil and NGLs production before royalties for the nine months ended September 30, 2026 averaged 1,221,452 bbl/d, an increase of 9% from 1,122,859 bbl/d for the nine months ended September 30, 2025. Crude oil and NGLs production before royalties for the third quarter of 2026 averaged 1,217,178 bbl/d, an increase of 4% from 1,175,604 bbl/d for the third quarter of 2025 and a decrease of 3% from 1,248,889 bbl/d for the second quarter of 2026. The increase in crude oil and NGLs production before royalties for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected the acquisitions completed in 2025 and 2026 in the North America Exploration and Production segment, the AOSP asset swap completed in the fourth quarter of 2025, and the impact of the planned turnaround at Scotford in the second quarter of 2025, partially offset by the planned turnaround at Horizon in the third quarter of 2026 in the Oil Sands Mining and Upgrading segment. The increase in crude oil and NGLs production before royalties for the third quarter of 2026 from the third quarter of 2025 primarily reflected pad additions in thermal in situ, strong drilling results, and the acquisitions completed in 2026 in the North America Exploration and Production segment, and the AOSP asset swap completed in the fourth quarter of 2025, partially offset by the planned turnaround at Horizon in the third quarter of 2026 in the Oil Sands Mining and Upgrading segment. The decrease in crude oil and NGLs production before royalties for the third quarter of 2026 from the second quarter of 2026 primarily reflected the planned turnaround at Horizon in the third quarter of 2026 in the Oil Sands Mining and Upgrading segment, partially offset by higher thermal in situ production due to a pad addition at Primrose, and strong drilling results in the North America Exploration and Production segment.

Annual crude oil and NGLs production before royalties for 2026 is targeted to average between 1,204,000 bbl/d and 1,243,000 bbl/d. Production targets constitute forward-looking statements. Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

Natural gas production before royalties for the nine months ended September 30, 2026 averaged 2,615 MMcf/d, an increase of 4% from 2,510 MMcf/d for the nine months ended September 30, 2025. Natural gas production before royalties for the third quarter of 2026 averaged 2,607 MMcf/d, comparable with 2,668 MMcf/d for the third quarter of 2025 and 2,567 MMcf/d for the second quarter of 2026. The increase in natural gas production before royalties for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected production associated with the light crude oil and liquids-rich natural gas acquisitions completed in 2025 and 2026, partially offset by natural field declines.

Annual natural gas production before royalties for 2026 is targeted to average between 2,595 MMcf/d and 2,635 MMcf/d. Production targets constitute forward-looking statements. Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the nine months ended September 30, 2026 averaged 625,243 bbl/d, an increase of 11% from 563,977 bbl/d for the nine months ended September 30, 2025. Record North America crude oil and NGLs production before royalties for the third quarter of 2026 of 658,116 bbl/d increased 13% from 584,625 bbl/d for the third quarter of 2025 and increased 7% from 613,745 bbl/d for the second quarter of 2026. The increase in North America crude oil and NGLs production before royalties for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected the acquisitions completed in 2025 and 2026, and strong drilling results. The increase in North America crude oil and NGLs production before royalties for the third quarter of 2026 from the third quarter of 2025 primarily reflected pad additions at thermal in situ, strong drilling results, and the acquisitions completed in 2026. The increase in North America crude oil and NGLs production before royalties for the third quarter of 2026 from the second quarter of 2026 primarily reflected a thermal in situ pad addition at Primrose in the third quarter of 2026, and strong drilling results.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, with record quarterly production averaging 299,632 bbl/d for the third quarter of 2026, an increase of 9% from 274,752 bbl/d for the third quarter of 2025 and from 275,607 bbl/d for the second quarter of 2026. The increase in thermal in situ production in the third quarter of 2026 from the third quarter of 2025 primarily reflected pad additions at Pike. The increase in thermal in situ production in the third quarter of 2026 from the second quarter of 2026 primarily reflected a pad addition at Primrose in the third quarter of 2026.

Pelican Lake heavy crude oil production before royalties for the third quarter of 2026 averaged 45,514 bbl/d, an increase of 8% from 42,070 bbl/d for the third quarter of 2025 and an increase of 3% from 44,053 bbl/d for the second quarter of 2026, primarily reflecting strong results at Driftwood.

North America natural gas production before royalties for the nine months ended September 30, 2026 averaged 2,611 MMcf/d, an increase of 5% from 2,498 MMcf/d for the nine months ended September 30, 2025. Natural gas production before royalties averaged 2,602 MMcf/d for the third quarter of 2026, comparable with 2,658 MMcf/d for the third quarter of 2025 and 2,563 MMcf/d for the second quarter of 2026. The increase in natural gas production before royalties for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected production associated with the light crude oil and liquids-rich natural gas acquisitions completed in 2025 and 2026, partially offset by natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the nine months ended September 30, 2026 averaged 585,099 bbl/d, an increase of 7% from 546,635 bbl/d for the nine months ended September 30, 2025. SCO production before royalties for the third quarter of 2026 averaged 543,089 bbl/d, a decrease of 7% from 581,136 bbl/d for the third quarter of 2025 and a decrease of 13% from 624,754 bbl/d for the second quarter of 2026. The increase in SCO production before royalties for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected the AOSP asset swap completed in the fourth quarter of 2025, and the impact of the planned turnaround at Scotford in the second quarter of 2025, partially offset by the planned turnaround at Horizon in the third quarter of 2026. The decrease in SCO production before royalties for the third quarter of 2026 from the third quarter of 2025 primarily reflected the planned turnaround at Horizon in the third quarter of 2026, partially offset by the AOSP asset swap completed in the fourth quarter of 2025. The decrease in SCO production before royalties for the third quarter of 2026 from the second quarter of 2026 primarily reflected the planned turnaround at Horizon in the third quarter of 2026.

International – Exploration and Production

International crude oil and NGLs production before royalties for the nine months ended September 30, 2026 averaged 11,110 bbl/d, a decrease of 9% from 12,247 bbl/d for the nine months ended September 30, 2025. International crude oil and NGLs production before royalties for the third quarter of 2026 averaged 15,973 bbl/d, an increase of 62% from 9,843 bbl/d for the third quarter of 2025 and an increase of 54% from 10,390 bbl/d for the second quarter of 2026. The decrease in International crude oil and NGLs production before royalties for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected planned North Sea abandonments conducted as part of the previously announced decommissioning plans, partially offset by the return to service of the FPSO at Baobab in June 2026. The increase in crude oil and NGLs production before royalties for the third quarter of 2026 from the comparable periods primarily reflected the return to service of the FPSO at Baobab in June 2026.

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Crude oil and NGLs ($/bbl) [1]					
Realized price [2]	**$ 95.93**	$ 105.11	$ 72.57	**$ 92.62**	$ 74.06
Transportation [3]	**6.26**	7.14	6.93	**6.80**	6.99
Realized price, net of transportation [2]	**89.67**	97.97	65.64	**85.82**	67.07
Royalties [4]	**23.25**	19.79	13.10	**19.01**	12.26
Production expense [5]	**13.76**	14.99	13.18	**14.09**	14.32
Netback [2]	**$ 52.66**	$ 63.19	$ 39.36	**$ 52.72**	$ 40.49
Natural gas ($/Mcf) [1]					
Realized price [6]	**$ 2.09**	$ 2.05	$ 1.49	**$ 2.49**	$ 2.37
Transportation [3]	**0.60**	0.60	0.57	**0.60**	0.60
Realized price, net of transportation	**1.49**	1.45	0.92	**1.89**	1.77
Royalties [4]	**0.06**	0.07	0.02	**0.09**	0.07
Production expense [5]	**1.18**	1.28	1.16	**1.23**	1.16
Netback [7]	**$ 0.25**	$ 0.10	$ (0.26)	**$ 0.57**	$ 0.54
Barrels of oil equivalent ($/BOE) [1]					
Realized price [2]	**$ 64.71**	$ 68.17	$ 45.31	**$ 62.00**	$ 49.09
Transportation [3]	**5.21**	5.70	5.38	**5.48**	5.54
Realized price, net of transportation [2]	**59.50**	62.47	39.93	**56.52**	43.55
Royalties [4]	**14.53**	12.02	7.53	**11.66**	7.31
Production expense [5]	**11.15**	12.00	10.50	**11.37**	11.22
Netback [2]	**$ 33.82**	$ 38.45	$ 21.90	**$ 33.49**	$ 25.02

(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			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Crude oil and NGLs ($/bbl) [1]					
North America [2]	**$ 95.34**	$ 104.77	$ 72.35	**$ 92.21**	$ 73.40
International average [3]	**$ 121.42**	$ 126.82	$ 94.08	**$ 118.79**	$ 102.18
North Sea [3]	**$ 127.18**	$ 122.97	$ 90.19	**$ 116.48**	$ 100.76
Offshore Africa [3]	**$ 118.29**	$ 141.00	$ 99.90	**$ 122.09**	$ 104.83
Crude oil and NGLs average [2]	**$ 95.93**	$ 105.11	$ 72.57	**$ 92.62**	$ 74.06
Natural gas ($/Mcf) [1] [3]					
North America	**$ 2.07**	$ 2.03	$ 1.45	**$ 2.48**	$ 2.32
International average	**$ 12.62**	$ 13.62	$ 11.22	**$ 12.73**	$ 12.76
North Sea	**$ 18.41**	$ 13.29	$ 8.57	**$ 14.09**	$ 12.70
Offshore Africa	**$ 9.34**	$ 14.02	$ 11.87	**$ 11.07**	$ 12.77
Natural gas average	**$ 2.09**	$ 2.05	$ 1.49	**$ 2.49**	$ 2.37
Average ($/BOE) [1] [2]	**$ 64.71**	$ 68.17	$ 45.31	**$ 62.00**	$ 49.09

(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 increased 26% to average $92.21 per bbl for the nine months ended September 30, 2026 from $73.40 per bbl for the nine months ended September 30, 2025. North America realized crude oil and NGLs prices averaged $95.34 per bbl for the third quarter of 2026, an increase of 32% from $72.35 per bbl for the third quarter of 2025 and a decrease of 9% from $104.77 per bbl for the second quarter of 2026. The increase in North America realized crude oil and NGLs prices per bbl for the three and nine months ended September 30, 2026 from the comparable periods in 2025 primarily reflected higher WTI benchmark pricing, partially offset by a widening of the WCS Heavy Differential. The decrease for the third quarter of 2026 from the second quarter of 2026 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 third quarter of 2026 contributed approximately 254,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 7% to average $2.48 per Mcf for the nine months ended September 30, 2026 from $2.32 per Mcf for the nine months ended September 30, 2025. North America realized natural gas prices increased 43% to average $2.07 per Mcf for the third quarter of 2026 from $1.45 per Mcf for the third quarter of 2025 and were comparable with $2.03 per Mcf for the second quarter of 2026. The increase in North America realized natural gas prices per Mcf for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected higher AECO and NYMEX benchmark pricing. The increase in North America realized natural gas prices per Mcf for the third quarter of 2026 from the third quarter of 2025 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)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025
Wellhead Price [1]			
Light and medium crude oil and NGLs ($/bbl)	**$ 87.67**	$ 95.30	$ 66.29
Pelican Lake heavy crude oil ($/bbl)	**$ 100.64**	$ 108.92	$ 75.94
Primary heavy crude oil ($/bbl)	**$ 99.24**	$ 109.09	$ 75.55
Thermal bitumen ($/bbl)	**$ 98.78**	$ 109.76	$ 74.83
Natural gas ($/Mcf)	**$ 2.07**	$ 2.03	$ 1.45

(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 increased 16% to average $118.79 per bbl for the nine months ended September 30, 2026 from $102.18 per bbl for the nine months ended September 30, 2025. International realized crude oil and NGLs prices increased 29% to average $121.42 per bbl for the third quarter of 2026 from $94.08 per bbl for the third quarter of 2025 and decreased 4% from $126.82 per bbl for the second quarter of 2026. 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			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 23.70**	$ 20.07	$ 13.21	**$ 19.27**	$ 12.51
International average	**$ 3.26**	$ 1.52	$ 2.05	**$ 2.23**	$ 1.71
North Sea	**$ 0.26**	$ 0.17	$ 0.35	**$ 0.18**	$ 0.17
Offshore Africa	**$ 4.89**	$ 6.47	$ 4.60	**$ 5.15**	$ 4.59
Crude oil and NGLs average	**$ 23.25**	$ 19.79	$ 13.10	**$ 19.01**	$ 12.26
Natural gas ($/Mcf) [1]					
North America	**$ 0.06**	$ 0.07	$ 0.02	**$ 0.09**	$ 0.07
Offshore Africa	**$ 0.42**	$ 0.64	$ 0.55	**$ 0.50**	$ 0.59
Natural gas average	**$ 0.06**	$ 0.07	$ 0.02	**$ 0.09**	$ 0.07
Average ($/BOE) [1]	**$ 14.53**	$ 12.02	$ 7.53	**$ 11.66**	$ 7.31

(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 and nine months ended September 30, 2026 and the comparable periods reflected movements in benchmark commodity prices, fluctuations in the WCS Heavy Differential and the impact of sliding scale royalty rates.

Crude oil and NGLs royalty rates[(1)] averaged approximately 21% of product sales for the nine months ended September 30, 2026 compared with 17% of product sales for the nine months ended September 30, 2025. Crude oil and NGLs royalty rates averaged approximately 25% of product sales for the third quarter of 2026 compared with 18% for the third quarter of 2025 and 19% for the second quarter of 2026. The increase in royalty rates for the three and nine months ended September 30, 2026 from the comparable periods in 2025 primarily reflected higher benchmark and annualized bitumen pricing, and the impact of sliding scale royalty rates. The increase in royalty rates for the third quarter of 2026 from the second quarter of 2026 primarily reflected higher annualized bitumen pricing, and the impact of sliding scale royalty rates.

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

Natural gas royalty rates averaged approximately 4% of product sales for the nine months ended September 30, 2026 compared with 3% of product sales for the nine months ended September 30, 2025. Natural gas royalty rates averaged approximately 3% of product sales for the third quarter of 2026 compared with 2% for the third quarter of 2025 and 3% for the second quarter of 2026. The increase in royalty rates for the three and nine months ended September 30, 2026 from the comparable periods in 2025 primarily reflected 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 nine months ended September 30, 2026 compared with 4% of product sales for the nine months ended September 30, 2025. Royalty rates as a percentage of product sales averaged approximately 4% for the third quarter of 2026 compared with 5% of product sales for the third quarter of 2025 and 5% for the second quarter of 2026.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 12.22**	$ 13.05	$ 11.97	**$ 12.75**	$ 12.17
International average	**$ 81.06**	$ 141.98	$ 134.12	**$ 101.35**	$ 106.02
North Sea	**$ 152.44**	$ 140.05	$ 188.98	**$ 130.20**	$ 145.38
Offshore Africa	**$ 42.28**	$ 149.08	$ 52.17	**$ 60.15**	$ 32.36
Crude oil and NGLs average	**$ 13.76**	$ 14.99	$ 13.18	**$ 14.09**	$ 14.32
Natural gas ($/Mcf) [1]					
North America	**$ 1.14**	$ 1.25	$ 1.14	**$ 1.21**	$ 1.12
International average	**$ 21.11**	$ 16.93	$ 8.18	**$ 17.03**	$ 9.02
North Sea	**$ 18.17**	$ 12.44	$ 15.64	**$ 12.46**	$ 12.34
Offshore Africa	**$ 22.78**	$ 22.46	$ 6.32	**$ 22.67**	$ 7.80
Natural gas average	**$ 1.18**	$ 1.28	$ 1.16	**$ 1.23**	$ 1.16
Average ($/BOE) [1]	**$ 11.15**	$ 12.00	$ 10.50	**$ 11.37**	$ 11.22

(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 nine months ended September 30, 2026 averaged $12.75 per bbl, an increase of 5% from $12.17 per bbl for the nine months ended September 30, 2025. North America crude oil and NGLs production expense for the third quarter of 2026 averaged $12.22 per bbl, comparable with $11.97 per bbl for the third quarter of 2025 and a decrease of 6% from $13.05 per bbl for the second quarter of 2026. The increase in crude oil and NGLs production expense per bbl for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected higher NGL processing costs resulting from acquisitions completed in the second half of 2025 and seasonal maintenance costs, partially offset by higher sales volumes in 2026. The decrease in crude oil and NGLs production expense per bbl for the third quarter of 2026 from the second quarter of 2026 primarily reflected higher sales volumes.

North America natural gas production expense for the nine months ended September 30, 2026 averaged $1.21 per Mcf, an increase of 8% from $1.12 per Mcf for the nine months ended September 30, 2025. North America natural gas production expense for the third quarter of 2026 of $1.14 per Mcf was comparable with $1.14 per Mcf for the third quarter of 2025 and decreased 9% from $1.25 per Mcf for the second quarter of 2026. The increase in natural gas production expense per Mcf for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected higher service costs. The decrease in natural gas production expense per Mcf for the third quarter of 2026 from the second quarter of 2026 primarily reflected lower energy costs.

International

International crude oil and NGLs production expense for the nine months ended September 30, 2026 averaged $101.35 per bbl, a decrease of 4% from $106.02 per bbl for the nine months ended September 30, 2025. International crude oil and NGLs production expense for the third quarter of 2026 of $81.06 per bbl decreased 40% from $134.12 per bbl for the third quarter of 2025 and decreased 43% from $141.98 per bbl for the second quarter of 2026. The decrease in crude oil and NGLs production expense per bbl for the three and nine months ended September 30, 2026 from the comparable periods primarily reflected the return to service of the FPSO at Baobab in June 2026.

ADJUSTED DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
North America	**$ 1,203**	$ 1,135	$ 1,188	**$ 3,469**	$ 3,365
North Sea	**9**	6	1,285	**21**	1,358
Offshore Africa	**41**	12	20	**67**	92
Depletion, depreciation and amortization	**$ 1,253**	$ 1,153	$ 2,493	**$ 3,557**	$ 4,815
Less: Recoverability charge [1]	**—**	—	1,258	**—**	1,258
Adjusted depletion, depreciation and amortization [2]	**$ 1,253**	$ 1,153	$ 1,235	**$ 3,557**	$ 3,557
$/BOE [3]	**$ 12.25**	$ 12.09	$ 13.08	**$ 12.16**	$ 13.10

(1) During the third quarter of 2025, the Company recognized a recoverability charge of $1,258 million in depletion, depreciation and amortization expense related to the abandonment and decommissioning of its North Sea assets.

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

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

Adjusted depletion, depreciation and amortization expense for the nine months ended September 30, 2026 averaged $12.16 per BOE, a decrease of 7% from $13.10 per BOE for the nine months ended September 30, 2025. Adjusted depletion, depreciation and amortization expense for the third quarter of 2026 averaged $12.25 per BOE, a decrease of 6% from $13.08 per BOE for the third quarter of 2025 and comparable with $12.09 per BOE for the second quarter of 2026. The decrease in adjusted depletion, depreciation and amortization expense per BOE for the three and nine months ended September 30, 2026 from the comparable periods in 2025 primarily reflected higher sales volumes in 2026.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
North America	**$ 55**	$ 54	$ 57	**$ 164**	$ 163
North Sea	**21**	21	13	**62**	41
Offshore Africa	**1**	1	3	**4**	7
Asset retirement obligation accretion	**$ 77**	$ 76	$ 73	**$ 230**	$ 211
$/BOE [(1)]	**$ 0.75**	$ 0.80	$ 0.77	**$ 0.79**	$ 0.78

(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 nine months ended September 30, 2026 averaged $0.79 per BOE, comparable with $0.78 per BOE for the nine months ended September 30, 2025. Asset retirement obligation accretion expense for the third quarter of 2026 averaged $0.75 per BOE, a decrease of 3% from $0.77 per BOE for the third quarter of 2025 and a decrease of 6% from $0.80 per BOE for the second quarter of 2026. The decrease in asset retirement obligation accretion expense per BOE for the third quarter of 2026 from the third quarter of 2025 primarily reflected higher sales volumes in 2026, partially offset by the impact of revisions in cost and timing estimates in the North Sea in the second half of 2025. The decrease in asset retirement obligation accretion expense per BOE for the third quarter of 2026 from the second quarter of 2026 primarily reflected higher sales volumes in the third quarter of 2026.

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, achieving quarterly SCO production of 543,089 bbl/d during the third quarter of 2026, reflecting the planned turnaround at Horizon during the quarter.

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

	Three Months Ended			Nine Months Ended	
($/bbl)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Realized SCO sales price [(1)]	**$ 114.56**	$ 125.78	$ 87.85	**$ 110.26**	$ 90.45
Bitumen value for royalty purposes [(2)]	**$ 89.98**	$ 92.72	$ 68.06	**$ 83.22**	$ 69.06
Bitumen royalties [(3)]	**$ 26.63**	$ 23.38	$ 15.80	**$ 21.70**	$ 15.49
Transportation [(4)]	**$ 2.49**	$ 2.57	$ 3.86	**$ 2.56**	$ 3.59

(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 $110.26 per bbl for the nine months ended September 30, 2026, an increase of 22% from $90.45 per bbl for the nine months ended September 30, 2025. The realized SCO sales price averaged $114.56 per bbl for the third quarter of 2026, an increase of 30% from $87.85 per bbl for the third quarter of 2025 and a decrease of 9% from $125.78 per bbl for the second quarter of 2026. The increase in the realized SCO sales price per bbl for the three and nine months ended September 30, 2026 from the comparable periods in 2025 primarily reflected higher WTI benchmark pricing combined with a strong SCO premium over WTI, partially offset by changes in the product sales mix between periods. The decrease in the realized SCO sales price per bbl for the third quarter of 2026 from the second quarter of 2026 primarily reflected lower WTI benchmark pricing.

The fluctuations in bitumen royalties per bbl in any particular period reflect the prevailing annualized bitumen value for royalty purposes, and the impact of sliding scale royalty rates. The increase in bitumen royalties per bbl for the three and nine months ended September 30, 2026 from the comparable periods primarily reflected higher annualized bitumen pricing, and the impact of sliding scale royalty rates.

Transportation expense averaged $2.56 per bbl for the nine months ended September 30, 2026, a decrease of 29% from $3.59 per bbl for the nine months ended September 30, 2025. Transportation expense averaged $2.49 per bbl for the third quarter of 2026, a decrease of 35% from $3.86 per bbl for the third quarter of 2025 and comparable with $2.57 per bbl for the second quarter of 2026. The decrease in transportation expense per bbl for the three and nine months ended September 30, 2026 from the comparable periods in 2025 primarily reflected lower transportation expense following the recognition of the Corridor pipeline as a lease asset following the AOSP asset swap in the fourth quarter of 2025. The decrease in transportation expense per bbl for the third quarter of 2026 from the third quarter of 2025 also reflected lower volumes shipped to the US Gulf Coast in 2026.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Production expense, excluding natural gas costs	**$ 1,288**	$ 1,221	$ 1,116	**$ 3,723**	$ 3,336
Natural gas costs	**34**	38	19	**127**	104
Production expense	**$ 1,322**	$ 1,259	$ 1,135	**$ 3,850**	$ 3,440

	Three Months Ended			Nine Months Ended	
($/bbl)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Production expense, excluding natural gas costs [1]	**$ 25.13**	$ 21.52	$ 20.93	**$ 23.06**	$ 22.28
Natural gas costs [2]	**0.67**	0.67	0.36	**0.79**	0.70
Production expense [3]	**$ 25.80**	$ 22.19	$ 21.29	**$ 23.85**	$ 22.98
Sales volumes (bbl/d)	**557,018**	623,486	579,209	**591,380**	548,197

(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 nine months ended September 30, 2026 averaged $23.85 per bbl, an increase of 4% from $22.98 per bbl for the nine months ended September 30, 2025. Production expense for the third quarter of 2026 averaged $25.80 per bbl, an increase of 21% from $21.29 per bbl for the third quarter of 2025 and an increase of 16% from $22.19 per bbl for the second quarter of 2026. The increase in production expense per bbl for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected higher service and energy costs, including diesel costs, partially offset by higher sales volumes in 2026. The increase in production expense per bbl for the third quarter of 2026 from the comparable periods primarily reflected the impact of the planned turnaround at Horizon in the third quarter of 2026.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Depletion, depreciation and amortization	**$ 791**	$ 744	$ 713	**$ 2,257**	$ 2,018
$/bbl [1]	**$ 15.43**	$ 13.11	$ 13.38	**$ 13.98**	$ 13.49

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

Depletion, depreciation and amortization expense for the nine months ended September 30, 2026 averaged $13.98 per bbl, an increase of 4% from $13.49 per bbl for the nine months ended September 30, 2025. Depletion, depreciation and amortization expense for the third quarter of 2026 of $15.43 per bbl increased 15% from $13.38 per bbl for the third quarter of 2025 and increased 18% from $13.11 per bbl for the second quarter of 2026. The increase in depletion, depreciation and amortization expense per bbl for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected a higher depletable base due to the gain recognized on the AOSP mine assets and the recognition of the Corridor pipeline as a lease asset, both arising from the AOSP asset swap in the fourth quarter of 2025, partially offset by the impact of higher sales volumes in 2026. The increase in depletion, depreciation and amortization expense per bbl for the third quarter of 2026 from the third quarter of 2025 primarily reflected the impact of the planned turnaround at Horizon in the third quarter of 2026, a higher depletable base due to the gain recognized on the AOSP mine assets and the recognition of the Corridor pipeline as a lease asset, both arising from the AOSP asset swap in the fourth quarter of 2025. The increase in depletion, depreciation and amortization expense per bbl for the third quarter of 2026 from the second quarter of 2026 primarily reflected the impact of the planned turnaround at Horizon in the third quarter of 2026.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Asset retirement obligation accretion	**$ 21**	$ 22	$ 22	**$ 64**	$ 65
$/bbl [1]	**$ 0.42**	$ 0.38	$ 0.40	**$ 0.40**	$ 0.43

(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 nine months ended September 30, 2026 of $0.40 per bbl decreased 7% from $0.43 per bbl for the nine months ended September 30, 2025. Asset retirement obligation accretion expense for the third quarter of 2026 of $0.42 per bbl increased 5% from $0.40 per bbl for the third quarter of 2025 and increased 11% from $0.38 per bbl for the second quarter of 2026. The decrease in asset retirement obligation accretion expense per bbl for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected higher sales volumes in 2026. The increase in asset retirement obligation accretion expense per bbl for the third quarter of 2026 from the comparable periods primarily reflected lower sales volumes in the third quarter of 2026.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended Sep 30 2026	Jun 30 2026	Sep 30 2025	Nine Months Ended Sep 30 2026	Sep 30 2025
Product sales					
Midstream activities	**$ 26**	$ 23	$ 24	**$ 72**	$ 68
NWRP, refined product sales and other	**365**	346	106	**988**	464
Segmented revenue	**391**	369	130	**1,060**	532
Less:					
NWRP, refining toll	**72**	85	70	**214**	199
Midstream activities	**5**	8	7	**19**	17
Production expense	**77**	93	77	**233**	216
NWRP, feedstock costs	**221**	241	82	**632**	359
Transportation expense	**4**	4	3	**12**	38
Depreciation	**4**	5	5	**13**	13
NWRP, partnership distribution	**(11)**	—	—	**(11)**	—
Segmented earnings (loss)	**$ 96**	$ 26	$ (37)	**$ 181**	$ (94)

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's processing design capacity is 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. Bitumen feedstock throughput can exceed design capacity when asset reliability and operational performance support higher processing rates. 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 third quarter of 2026, production of ultra-low sulphur diesel and other refined products averaged 84,730 BOE/d (21,182 BOE/d to the Company) (three months ended June 30, 2026 – 92,748 BOE/d; 23,187 BOE/d to the Company; three months ended September 30, 2025 – 38,434 BOE/d; 9,608 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at September 30, 2026, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $373 million (December 31, 2025 – $496 million). For the three months ended September 30, 2026, the Company's recovery of its share of unrecognized equity losses was $43 million (three months ended June 30, 2026 – recovery of unrecognized equity losses of $66 million; three months ended September 30, 2025 – recovery of unrecognized equity losses of $21 million; nine months ended September 30, 2026 – recovery of unrecognized equity losses of $134 million; nine months ended September 30, 2025 – recovery of unrecognized equity losses of $26 million). For the three and nine months ended September 30, 2026, the Company received partnership distributions of $11 million.

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Administration expense	**$ 165**	$ 159	$ 152	**$ 478**	$ 455
$/BOE [1]	**$ 1.08**	$ 1.04	$ 1.03	**$ 1.05**	$ 1.08
Sales volumes (BOE/d) [2]	**1,668,438**	1,672,106	1,606,723	**1,663,437**	1,543,203

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

(2) Total Company sales volumes.

Administration expense for the nine months ended September 30, 2026 averaged $1.05 per BOE, a decrease of 3% from $1.08 per BOE for the nine months ended September 30, 2025. Administration expense for the third quarter of 2026 of $1.08 per BOE increased 5% from $1.03 per BOE for the third quarter of 2025 and increased 4% from $1.04 per BOE for the second quarter of 2026. The decrease in administration expense per BOE for the nine months ended September 30, 2026 from the nine months ended September 30, 2025 primarily reflected higher sales volumes, partially offset by higher personnel and corporate costs. The increase in administration expense per BOE for the third quarter of 2026 from the third quarter of 2025 primarily reflected higher personnel costs, partially offset by higher sales volumes. The increase in administration expense per BOE for the third quarter of 2026 from the second quarter of 2026 primarily reflected higher personnel costs and lower overhead recoveries.

SHARE-BASED COMPENSATION

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Share-based compensation expense (recovery)	**$ 431**	$ (196)	$ 63	**$ 879**	$ 97

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 $879 million of share-based compensation expense for the nine months ended September 30, 2026 primarily as a result of changes in the Company's share price, the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, and the impact of vested stock options exercised or surrendered during the period.

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except effective interest rate)	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Interest and other financing expense	**$ 220**	$ 238	$ 93	**$ 776**	$ 589
Less: Interest (income) and other expense [1]	**(32)**	(20)	(174)	**12**	(187)
Interest expense on long-term debt and lease liabilities [1]	**$ 252**	$ 258	$ 267	**$ 764**	$ 776
Average current and long-term debt [2]	**$ 17,097**	$ 17,500	$ 18,802	**$ 17,347**	$ 18,500
Average lease liabilities [2]	**2,973**	3,037	1,469	**3,029**	1,424
Average long-term debt and lease liabilities [2]	**$ 20,070**	$ 20,537	$ 20,271	**$ 20,376**	$ 19,924
Average effective interest rate [3] [4]	**4.9%**	4.9%	5.2%	**4.9%**	5.1%
Interest and other financing expense ($/BOE) [5]	**$ 1.43**	$ 1.57	$ 0.62	**$ 1.71**	$ 1.40
Sales volumes (BOE/d) [6]	**1,668,438**	1,672,106	1,606,723	**1,663,437**	1,543,203

(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 nine months ended September 30, 2026 averaged $1.71 per BOE, an increase of 22% from $1.40 per BOE for the nine months ended September 30, 2025. Interest and other financing expense for the third quarter of 2026 of $1.43 per BOE increased 131% from $0.62 per BOE for the third quarter of 2025 and decreased 9% from $1.57 per BOE for the second quarter of 2026. The increase in interest and other financing expense per BOE for the three and nine months ended September 30, 2026 from the comparable periods in 2025 primarily reflected the impact of interest on tax recoveries in the North Sea in the third quarter of 2025, and higher average lease liabilities following the recognition of the Corridor pipeline in the fourth quarter of 2025, partially offset by higher sales volumes in 2026 and lower average long-term debt outstanding. The decrease in interest and other financing expense per BOE for the third quarter of 2026 from the second quarter of 2026 primarily reflected lower average long-term debt outstanding combined with higher interest income in the third quarter.

The Company's average effective interest rate for the three and nine months ended September 30, 2026 was 4.9%, a decrease from 5.1% for the nine months ended September 30, 2025, and 5.2% for the third quarter of 2025, and was comparable with the second quarter of 2026, reflecting interest rates on the medium-term note issuances in December 2025, combined with a lower effective interest rate on higher average lease liabilities.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Foreign currency forward contracts	**$ 3**	$ 49	$ 52	**$ 95**	$ (83)
Foreign currency put options	**—**	—	—	**—**	23
Natural gas financial contracts [1] [2] [3]	**4**	3	2	**9**	(2)
Net realized loss (gain)	**7**	52	54	**104**	(62)
Foreign currency forward contracts	**4**	(4)	—	**1**	(5)
Natural gas financial contracts [1] [2] [3]	**(2)**	(2)	4	**(1)**	8
Natural gas embedded derivative [4]	**70**	(2)	156	**380**	145
Net unrealized loss (gain)	**72**	(8)	160	**380**	148
Net loss	**$ 79**	$ 44	$ 214	**$ 484**	$ 86

(1) In the third quarter of 2026, the Company entered into fixed price financial contracts to buy 25,000 MMBtu/d of natural gas at US$1.32 AECO for the period of August to December 2026, and 25,000 MMBtu/d of natural gas at US$1.74 AECO for the period of January to December 2027.

(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 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 15 to the financial statements.

The Company recorded a net realized risk management loss of $104 million for the nine months ended September 30, 2026 and a net realized risk management loss of $7 million for the third quarter of 2026.

The Company recorded a net unrealized risk management loss of $380 million ($292 million after tax of $88 million) for the nine months ended September 30, 2026 and a net unrealized risk management loss of $72 million ($55 million after tax of $17 million) for the third quarter of 2026 (nine months ended September 30, 2025 – unrealized loss of $148 million ($114 million after tax of $34 million); three months ended June 30, 2026 – unrealized gain of $8 million ($6 million after tax of $2 million); three months ended September 30, 2025 – unrealized loss of $160 million ($124 million after tax of $36 million)).

Further details related to outstanding derivative financial instruments as at September 30, 2026 are disclosed in note 15 to the financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Net realized loss	**$ —**	$ 24	$ 21	**$ 1**	$ 121
Net unrealized loss (gain)	**3**	157	269	**445**	(677)
Net loss (gain) [1]	**$ 3**	$ 181	$ 290	**$ 446**	$ (556)

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

The net realized foreign exchange loss for the nine months ended September 30, 2026 primarily reflected exchange rate fluctuations on the settlement of US dollar debt and working capital items denominated in US dollars.

The net unrealized foreign exchange loss for the nine months ended September 30, 2026 primarily reflected the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at September 30, 2026 was US$0.7047 (June 30, 2026 – US$0.7040; September 30, 2025 – US$0.7191).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
North America [1]	**$ 1,098**	$ 1,164	$ 499	**$ 2,933**	$ 1,597
North Sea	**(19)**	(46)	(37)	**(118)**	(108)
Offshore Africa	**5**	1	—	**6**	5
Current PRT – North Sea	**(66)**	(49)	(45)	**(180)**	(133)
Other taxes	**1**	3	2	**6**	7
Current income tax	**1,019**	1,073	419	**2,647**	1,368
Deferred corporate income tax	**(149)**	275	(143)	**67**	(130)
Deferred PRT – North Sea	**38**	37	(389)	**(39)**	(362)
Deferred income tax	**(111)**	312	(532)	**28**	(492)
Income tax	**$ 908**	$ 1,385	$ (113)	**$ 2,675**	$ 876
Earnings before taxes	**$ 3,905**	$ 5,888	$ 487	**$ 11,523**	$ 6,393
Effective tax rate on net earnings [2]	**23%**	24%	(23)%	**23%**	14%

($ millions, except effective tax rates)	Three Months Ended			Nine Months Ended	
	Sep 30 2026	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Income tax	**$ 908**	$ 1,385	$ (113)	**$ 2,675**	$ 876
Tax effect on non-operating items [3]	**60**	(14)	603	**172**	607
Current PRT – North Sea	**66**	49	45	**180**	133
Deferred PRT – North Sea	**(38)**	(37)	(31)	**39**	(58)
Other taxes	**(1)**	(3)	(2)	**(6)**	(7)
Effective tax on adjusted net earnings	**$ 995**	$ 1,380	$ 502	**$ 3,060**	$ 1,551
Adjusted net earnings from operations [4]	**$ 3,427**	$ 4,568	$ 1,801	**$ 10,441**	$ 5,733
Adjusted net earnings from operations, before taxes	**$ 4,422**	$ 5,948	$ 2,303	**$ 13,501**	$ 7,284
Effective tax rate on adjusted net earnings from operations [5] [6]	**23%**	23%	22%	**23%**	21%

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

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

(3) Includes the net income tax effect on PSUs, certain stock options, unrealized risk management, and a recoverability charge related to the increase in estimated future abandonment costs for the Ninian field and T-Block assets in the North Sea in the third quarter of 2025.

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

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

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

The effective tax rate on net earnings and adjusted net earnings from operations for the three and nine months ended September 30, 2026 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings.

The current and deferred corporate income tax and the current and deferred PRT in the North Sea for the three and nine months ended September 30, 2026 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the decommissioning activities in the North Sea.

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			Nine Months Ended	
($ millions)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Exploration and Production					
Exploration and Evaluation Assets					
Net expenditures	**$ 16**	$ 4	$ 18	**$ 43**	$ 42
Net property acquisitions	**(2)**	21	45	**82**	78
Total Exploration and Evaluation Assets	**14**	25	63	**125**	120
Property, Plant and Equipment					
Net property acquisitions	**—**	741	761	**1,451**	970
Well drilling, completion and equipping	**729**	713	499	**2,076**	1,593
Production and related facilities	**340**	405	365	**1,124**	1,162
Other	**18**	17	13	**(100)**	32
Total Property, Plant and Equipment	**1,087**	1,876	1,638	**4,551**	3,757
Total Exploration and Production	**1,101**	1,901	1,701	**4,676**	3,877
Oil Sands Mining and Upgrading					
Project costs	**72**	61	76	**177**	227
Sustaining capital	**606**	404	312	**1,295**	934
Turnaround costs	**93**	22	13	**126**	233
Other	**2**	3	2	**7**	6
Total Oil Sands Mining and Upgrading	**773**	490	403	**1,605**	1,400
Midstream and Refining	**2**	2	2	**5**	6
Head Office	**7**	12	18	**30**	59
Net capital expenditures	**$ 1,883**	$ 2,405	$ 2,124	**$ 6,316**	$ 5,342
By Segment					
North America	**$ 985**	$ 1,754	$ 1,606	**$ 4,268**	$ 3,552
North Sea	**4**	3	5	**9**	16
Offshore Africa	**112**	144	90	**399**	309
Oil Sands Mining and Upgrading	**773**	490	403	**1,605**	1,400
Midstream and Refining	**2**	2	2	**5**	6
Head Office	**7**	12	18	**30**	59
Net capital expenditures	**$ 1,883**	$ 2,405	$ 2,124	**$ 6,316**	$ 5,342
Abandonment expenditures	**$ 248**	$ 182	$ 189	**$ 677**	$ 570

(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.

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 $6,316 million for the nine months ended September 30, 2026 compared with $5,342 million for the nine months ended September 30, 2025. Net capital expenditures were $1,883 million for the third quarter of 2026 compared with $2,124 million for the third quarter of 2025 and $2,405 million for the second quarter of 2026. In addition, the Company reported abandonment expenditures of $677 million for the nine months ended September 30, 2026 compared with $570 million for the nine months ended September 30, 2025. Abandonment expenditures were $248 million for the third quarter of 2026 compared with $189 million for the third quarter of 2025 and $182 million for the second quarter of 2026.

Drilling Activity [1] [2]

	Three Months Ended			Nine Months Ended	
(number of net wells)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Net successful crude oil wells [3]	**152**	118	89	**383**	244
Net successful natural gas wells	**11**	23	17	**58**	58
Dry wells	**1**	—	—	**2**	1
Total	**164**	141	106	**443**	303
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 third quarter of 2026, the Company drilled 11 net natural gas wells, 61 net primary heavy crude oil wells, 10 net Pelican Lake heavy crude oil wells, 45 net thermal bitumen wells, and 37 net light crude oil wells.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2026**	Jun 30 2026	Dec 31 2025	Sep 30 2025
Adjusted working capital [1]	**$ 1,696**	$ 2,222	$ 42	$ (303)
Long-term debt, net [2]	**$ 12,117**	$ 14,526	$ 15,944	$ 17,155
Shareholders' equity	**$ 46,930**	$ 46,796	$ 44,366	$ 40,461
Debt to book capitalization [2]	**20.5%**	23.7%	26.4%	29.8%
After-tax return on average capital employed [3]	**24.3%**	20.6%	19.5%	12.8%

(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 September 30, 2026, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities, and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt are dependent on factors discussed in the 'Business Environment' section of this MD&A and in the 'Risks and Uncertainties' section of the Company's annual MD&A for the year ended December 31, 2025. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings, as determined by independent rating agencies and market conditions.

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

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

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers, and joint venture partners on a regular basis and, where appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;

- Actively managing the allocation of capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments, and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
  - During the first quarter of 2026, the Company cancelled the $140 million portion of its $2,565 million revolving syndicated credit facility, maturing June 2027, reducing the capacity to $2,425 million, with a maturity of June 2029.
  - Borrowings under the Company's credit facilities may be made by way of pricing referenced to CORRA, SOFR, US base rate or Canadian prime rate.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - During the third quarter of 2026, the Company repaid $441 million of 3.42% medium-term notes originally due December 1, 2026.
  - In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at September 30, 2026, the Company had $1,350 million remaining on its base shelf prospectus.
  - In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$4,500 million of debt securities in the United States, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at September 30, 2026, the Company had US$3,003 million remaining on its base shelf prospectus.

As at September 30, 2026, the Company had undrawn bank credit facilities of $5,421 million, and a fully drawn non-revolving term credit facility of $4,000 million. Including cash and cash equivalents, the Company had approximately $9,937 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit.

Long-term debt, net was $12,117 million as at September 30, 2026 (December 31, 2025 – $15,944 million), resulting in a debt to book capitalization ratio of 20.5% (December 31, 2025 – 26.4%). The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at September 30, 2026, the Company was in compliance with this covenant.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt as at September 30, 2026 are discussed in note 8 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 September 30, 2026, the maturity dates of certain financial liabilities, including long-term debt and other long-term liabilities and related interest payments, were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt [1]	$ 1,772	$ 4,254	$ 2,875	$ 7,807
Other long-term liabilities [2] [3]	$ 339	$ 286	$ 614	$ 2,275
Interest and other financing expense [4]	$ 964	$ 734	$ 1,811	$ 3,342

(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, $331 million; one to less than two years, $286 million; two to less than five years, $614 million; and thereafter, $1,712 million.

(3) Includes a gross derivative liability of $563 million associated with the Company's natural gas embedded derivative. The gross liability is offset by a gross derivative asset of $126 million, resulting in a net liability of $437 million.

(4) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at September 30, 2026.

Share Capital

As at September 30, 2026, there were 2,045,524,000 common shares outstanding (December 31, 2025 – 2,081,578,000 common shares) and 54,791,000 stock options outstanding (December 31, 2025 – 54,734,000 stock options). As at November 3, 2026, the Company had 2,035,130,000 common shares outstanding and 53,095,000 stock options outstanding.

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

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

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

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

For the nine months ended September 30, 2026, the Company purchased 46,975,000 common shares at a weighted average price of $64.01 per common share for a total cost, including tax, of $3,055 million. Retained earnings were reduced by $2,786 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2026, up to and including November 3, 2026, the Company purchased 10,800,000 common shares at a weighted average price of $73.64 per common share for a total cost, including tax, of $811 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at September 30, 2026:

($ millions)	Remaining 2026	2027	2028	2029	2030	Thereafter
Product transportation, purchases, and processing [1] [2]	$ 590	$ 2,280	$ 2,167	$ 2,014	$ 1,852	$ 19,882
North West Redwater Partnership service toll [3]	$ 23	$ 96	$ 97	$ 95	$ 95	$ 3,877
Offshore vessels and decommissioning equipment	$ 324	$ —	$ —	$ —	$ —	$ —
Field equipment and supplies	$ 52	$ 122	$ 121	$ 24	$ 24	$ 170
Office leases and other	$ 72	$ 67	$ 20	$ 20	$ 19	$ 179

(1) The Company's commitment under its product transportation agreement on the TMX pipeline reflects the toll approved by the Canada Energy Regulator in the third quarter of 2026. The Company's product transportation commitment was extended through 2046, with capacity increased to approximately 178,000 bbl/d.

(2) In the second quarter of 2026, the Company executed crude oil transportation agreements delivering between 150,000 bbl/d and 165,000 bbl/d of new pipeline capacity to US markets, with service currently expected to commence in the fourth quarter of 2028. These agreements are subject to certain conditions precedent, including a final investment decision by the project proponents and certain regulatory approvals. Accordingly, the related agreements will not be recognized as commitments until the completion of all conditions precedent. The transportation agreements have a term of 20 years and, if all conditions are met, will result in transportation payments of approximately $500 million to $550 million annually being added to the Company's commitments.

(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 $1,728 million of interest payable over the 40-year tolling period, ending in 2058.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the nine months ended September 30, 2026 that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting. Due to inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

NON-GAAP AND OTHER FINANCIAL MEASURES

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

Adjusted Net Earnings from Operations

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Net earnings	**$ 2,997**	$ 4,503	$ 600	**$ 8,848**	$ 5,517
Share-based compensation, net of tax [1]	**388**	(184)	59	**795**	87
Unrealized risk management loss (gain), net of tax [2]	**55**	(6)	124	**292**	114
Unrealized foreign exchange loss (gain), net of tax [3]	**3**	157	269	**445**	(677)
Realized foreign exchange (gain) loss on financing activities, net of tax [4]	**(16)**	98	54	**61**	77
Gain on acquisition, net of tax [5]	**—**	—	—	**—**	(80)
Recoverability charge, net of tax [6]	**—**	—	695	**—**	695
Non-operating items, net of tax	**430**	65	1,201	**1,593**	216
Adjusted net earnings from operations	**$ 3,427**	$ 4,568	$ 1,801	**$ 10,441**	$ 5,733

(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 September 30, 2026 was an expense of $431 million (three months ended June 30, 2026 – $196 million recovery; three months ended September 30, 2025 – $63 million expense; nine months ended September 30, 2026 – $879 million expense; nine months ended September 30, 2025 – $97 million expense).

(2) Derivative financial instruments are recognized at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than those amounts reflected in the financial statements due to changes in prices of the underlying items hedged, primarily natural gas and foreign exchange. The pre-tax unrealized risk management loss for the three months ended September 30, 2026 was $72 million (three months ended June 30, 2026 – $8 million gain; three months ended September 30, 2025 – $160 million loss; nine months ended September 30, 2026 – $380 million loss; nine months ended September 30, 2025 – $148 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 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 third quarter of 2025, the Company recognized a pre-tax recoverability charge of $1,258 million ($695 million after-tax) in depletion, depreciation and amortization relating to the increase in estimated future abandonment costs for the Ninian field and T-Block assets in the North Sea. The costs are included in capital and abandonment expenditures, consistent with the treatment of all abandonment expenditures for the purpose of the Company's non-GAAP measures.

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			Nine Months Ended	
($ millions)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Cash flows from operating activities	**$ 7,010**	$ 6,823	$ 3,940	**$ 17,115**	$ 11,338
Net change in non-cash working capital	**(1,744)**	(120)	(432)	**(1,046)**	(538)
Abandonment expenditures	**248**	182	189	**677**	570
Movements in other long-term assets [(1)]	**8**	(19)	223	**16**	342
Adjusted funds flow	**$ 5,522**	$ 6,866	$ 3,920	**$ 16,762**	$ 11,712

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

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

Adjusted net earnings from operations and adjusted funds flow, per common share (basic and diluted) are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 14 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 17 to the financial statements.

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

Realized price ($/bbl and $/BOE) is a non-GAAP ratio calculated as realized crude oil and NGLs sales and total realized BOE sales (non-GAAP financial measures) divided by respective sales volumes. Realized crude oil and NGLs sales and total realized BOE sales is comprised of crude oil and NGLs sales and natural gas sales less blending and feedstock costs and other by-product sales, as disclosed in note 17 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			Nine Months Ended	
($ millions, except bbl/d and $/bbl)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Crude oil and NGLs (bbl/d)					
North America	**661,688**	611,384	577,089	**626,596**	563,561
International					
North Sea	**5,347**	7,372	3,455	**5,687**	8,588
Offshore Africa	**9,843**	2,000	2,313	**3,984**	4,588
Total International	**15,190**	9,372	5,768	**9,671**	13,176
Total sales volumes	**676,878**	620,756	582,857	**636,267**	576,737
Crude oil and NGLs sales [1]	**$ 7,225**	$ 7,535	$ 4,773	**$ 20,185**	$ 15,052
Less: Blending and feedstock costs [2]	**1,251**	1,598	883	**4,097**	3,393
Realized crude oil and NGLs sales	**$ 5,974**	$ 5,937	$ 3,890	**$ 16,088**	$ 11,659
Realized price ($/bbl)	**$ 95.93**	$ 105.11	$ 72.57	**$ 92.62**	$ 74.06

(1) Crude oil and NGLs sales in note 17 to the financial statements.

(2) Blending and feedstock costs in note 17 to the financial statements.

	Three Months Ended			Nine Months Ended	
($ millions, except BOE/d and $/BOE)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Barrels of oil equivalent (BOE/d)					
North America	**1,095,373**	1,038,526	1,020,062	**1,061,734**	979,903
International					
North Sea	**5,658**	7,771	3,791	**6,047**	9,104
Offshore Africa	**10,389**	2,323	3,661	**4,276**	5,999
Total International	**16,047**	10,094	7,452	**10,323**	15,103
Total sales volumes	**1,111,420**	1,048,620	1,027,514	**1,072,057**	995,006
Barrels of oil equivalent sales [1]	**$ 7,727**	$ 8,013	$ 5,139	**$ 21,963**	$ 16,674
Less: Blending and feedstock costs [2]	**1,251**	1,598	883	**4,097**	3,393
Less: Sulphur income	**(141)**	(89)	(28)	**(278)**	(55)
Realized barrels of oil equivalent sales	**$ 6,617**	$ 6,504	$ 4,284	**$ 18,144**	$ 13,336
Realized price ($/BOE)	**$ 64.71**	$ 68.17	$ 45.31	**$ 62.00**	$ 49.09

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 17 to the financial statements.

(2) Blending and feedstock costs in note 17 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 17 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			Nine Months Ended	
($ millions, except $/bbl and royalty rates)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Crude oil and NGLs sales [1]	**$ 7,055**	$ 7,427	$ 4,724	**$ 19,871**	$ 14,685
Less: Blending and feedstock costs [2]	**1,251**	1,598	883	**4,097**	3,393
Realized crude oil and NGLs sales	**$ 5,804**	$ 5,829	$ 3,841	**$ 15,774**	$ 11,292
Realized crude oil and NGLs prices ($/bbl)	**$ 95.34**	$ 104.77	$ 72.35	**$ 92.21**	$ 73.40
Crude oil and NGLs royalties [3]	**$ 1,443**	$ 1,116	$ 702	**$ 3,296**	$ 1,925
Crude oil and NGLs royalty rates	**25%**	19%	18%	**21%**	17%

(1) Crude oil and NGLs sales in note 17 to the financial statements.

(2) Blending and feedstock costs in note 17 to the financial statements.

(3) Item is a component of royalties in note 17 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 17 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			Nine Months Ended	
($ millions, except for bbl/d and $/bbl)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
SCO sales volumes (bbl/d)	**557,018**	623,486	579,209	**591,380**	548,197
Crude oil and NGLs sales [1]	**$ 6,810**	$ 8,143	$ 5,255	**$ 20,490**	$ 15,157
Less: Blending and feedstock costs [2]	**940**	1,005	573	**2,688**	1,621
Realized SCO sales	**$ 5,870**	$ 7,138	$ 4,682	**$ 17,802**	$ 13,536
Realized SCO sales price ($/bbl)	**$ 114.56**	$ 125.78	$ 87.85	**$ 110.26**	$ 90.45

(1) Crude oil and NGLs sales in note 17 to the financial statements.

(2) Blending and feedstock costs in note 17 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, 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			Nine Months Ended	
($ millions)	**Sep 30 2026**	Jun 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Cash flows used in investing activities	**$ 1,640**	$ 2,468	$ 2,234	**$ 6,057**	$ 5,487
Net change in non-cash working capital	**243**	(63)	(110)	**259**	(145)
Net capital expenditures	**1,883**	2,405	2,124	**6,316**	5,342
Abandonment expenditures	**248**	182	189	**677**	570
Capital and abandonment expenditures	**$ 2,131**	$ 2,587	$ 2,313	**$ 6,993**	$ 5,912

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)	**Sep 30 2026**	Jun 30 2026	Dec 31 2025	Sep 30 2025
Undrawn bank credit facilities	**$ 5,421**	$ 5,356	$ 5,668	$ 4,201
Cash and cash equivalents	**4,516**	2,618	673	113
Liquidity	**$ 9,937**	$ 7,974	$ 6,341	$ 4,314

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 13 to the financial statements. A reconciliation of the Company's long-term debt, net is presented below.

($ millions)	**Sep 30 2026**	Jun 30 2026	Dec 31 2025	Sep 30 2025
Long-term debt	**$ 16,633**	$ 17,144	$ 16,617	$ 17,268
Less: Cash and cash equivalents	**4,516**	2,618	673	113
Long-term debt, net	**$ 12,117**	$ 14,526	$ 15,944	$ 17,155

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 13 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)	**Sep 30 2026**	Jun 30 2026	Dec 31 2025	Sep 30 2025
Interest adjusted after-tax return:				
Net earnings, 12 months trailing [(1)]	**$ 14,151**	$ 11,754	$ 10,820	$ 6,655
Interest and other financing expense, net of tax, 12 months trailing [(2)]	**784**	686	640	561
Interest adjusted after-tax return	**$ 14,935**	$ 12,440	$ 11,460	$ 7,216
12 months average current portion long-term debt [(3)]	**$ 1,140**	$ 1,059	$ 1,293	$ 1,529
12 months average long-term debt [(3)]	**15,785**	15,955	16,149	14,596
12 months average common shareholders' equity [(3)]	**44,638**	43,512	41,208	40,314
12 months average capital employed	**$ 61,563**	$ 60,526	$ 58,650	$ 56,439
After-tax return on average capital employed	**24.3%**	20.6%	19.5%	12.8%

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

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

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

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Sep 30 2026**	Dec 31 2025
ASSETS			
Current assets			
Cash and cash equivalents		**$ 4,516**	$ 673
Accounts receivable		**5,546**	3,999
Inventory		**2,984**	2,621
Prepaids and other		**481**	301
Current portion of other long-term assets	7	**151**	70
		13,678	7,664
Exploration and evaluation assets	4	**2,789**	2,651
Property, plant and equipment	5	**78,693**	77,645
Lease assets	6	**2,829**	3,001
Other long-term assets	7	**756**	869
		$ 98,745	$ 91,830
LIABILITIES			
Current liabilities			
Accounts payable		**$ 2,831**	$ 1,105
Accrued liabilities		**5,606**	4,255
Current income taxes payable		**1,331**	597
Current portion of long-term debt	8	**1,772**	441
Current portion of other long-term liabilities	9	**2,214**	1,665
		13,754	8,063
Long-term debt	8	**14,861**	16,176
Other long-term liabilities	9	**11,935**	11,936
Deferred income taxes		**11,265**	11,289
		51,815	47,464
SHAREHOLDERS' EQUITY			
Share capital	11	**11,762**	11,421
Retained earnings		**34,908**	32,726
Accumulated other comprehensive income	12	**260**	219
		46,930	44,366
		$ 98,745	$ 91,830

Commitments and contingencies (note 16)

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

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Sep 30 2026	Three Months Ended Sep 30 2025	Nine Months Ended Sep 30 2026	Nine Months Ended Sep 30 2025
Product sales	17	**$ 15,643**	$ 11,070	**$ 45,261**	$ 33,457
Less: royalties		**(2,850)**	(1,554)	**(6,917)**	(4,304)
Revenue		**12,793**	9,516	**38,344**	29,153
Expenses					
Production		**2,551**	2,220	**7,447**	6,751
Blending and feedstock		**2,643**	1,970	**8,180**	6,215
Transportation		**661**	721	**2,021**	2,081
Depletion, depreciation and amortization [(1)]	5,6	**2,048**	3,211	**5,827**	6,846
Administration		**165**	152	**478**	455
Share-based compensation	9	**431**	63	**879**	97
Asset retirement obligation accretion	9	**98**	95	**294**	276
Interest and other financing expense		**220**	93	**776**	589
Risk management loss	15	**79**	214	**484**	86
Foreign exchange loss (gain)		**3**	290	**446**	(556)
Gain on acquisition		**—**	—	**—**	(80)
Investment income	7	**(11)**	—	**(11)**	—
		8,888	9,029	**26,821**	22,760
Earnings before taxes		**3,905**	487	**11,523**	6,393
Current income tax expense	10	**1,019**	419	**2,647**	1,368
Deferred income tax (recovery) expense	10	**(111)**	(532)	**28**	(492)
Net earnings		**$ 2,997**	$ 600	**$ 8,848**	$ 5,517
Net earnings per common share					
Basic	14	**$ 1.46**	$ 0.29	**$ 4.27**	$ 2.64
Diluted	14	**$ 1.45**	$ 0.29	**$ 4.24**	$ 2.63

(1) Depletion, depreciation and amortization expense for the three and nine months ended September 30, 2025 includes $1,258 million for revisions to abandonment and decommissioning costs in the North Sea.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2026	Three Months Ended Sep 30 2025	Nine Months Ended Sep 30 2026	Nine Months Ended Sep 30 2025
Net earnings	**$ 2,997**	$ 600	**$ 8,848**	$ 5,517
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period, net of taxes of $nil (2025 – $1 million) – three months ended; $nil (2025 – $1 million) – nine months ended	**—**	9	**1**	15
Reclassification to net earnings, net of taxes of $nil (2025 – $1 million) – three months ended; $nil (2025 – $2 million) – nine months ended	**(2)**	(9)	**(4)**	(16)
	(2)	—	**(3)**	(1)
Foreign currency translation adjustment				
Translation of net investment	**—**	30	**44**	(65)
Other comprehensive (loss) income, net of taxes	**(2)**	30	**41**	(66)
Comprehensive income	**$ 2,995**	$ 630	**$ 8,889**	$ 5,451

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended Sep 30 2026	Nine Months Ended Sep 30 2025
Share capital	11		
Balance – beginning of period		**$ 11,421**	$ 11,064
Issued upon exercise of stock options		**345**	191
Previously recognized liability on stock options exercised for common shares		**265**	207
Purchase of common shares under Normal Course Issuer Bid		**(269)**	(145)
Balance – end of period		**11,762**	11,317
Retained earnings			
Balance – beginning of period		**32,726**	28,103
Net earnings		**8,848**	5,517
Dividends on common shares	11	**(3,880)**	(3,686)
Purchase of common shares under Normal Course Issuer Bid, including tax	11	**(2,786)**	(1,025)
Balance – end of period		**34,908**	28,909
Accumulated other comprehensive income	12		
Balance – beginning of period		**219**	301
Other comprehensive income (loss), net of taxes		**41**	(66)
Balance – end of period		**260**	235
Shareholders' equity		**$ 46,930**	$ 40,461

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Sep 30 2026	Three Months Ended Sep 30 2025	Nine Months Ended Sep 30 2026	Nine Months Ended Sep 30 2025
Operating activities					
Net earnings		**$ 2,997**	$ 600	**$ 8,848**	$ 5,517
Non-cash items					
Depletion, depreciation and amortization	5,6	**2,048**	3,211	**5,827**	6,846
Share-based compensation		**431**	63	**879**	97
Asset retirement obligation accretion		**98**	95	**294**	276
Unrealized risk management loss	15	**72**	160	**380**	148
Unrealized foreign exchange loss (gain)		**3**	269	**445**	(677)
Gain on acquisition		**—**	—	**—**	(80)
Deferred income tax (recovery) expense		**(111)**	(532)	**28**	(492)
Realized foreign exchange on financing activities [1]		**(16)**	54	**61**	77
Abandonment expenditures	9	**(248)**	(189)	**(677)**	(570)
Other		**(8)**	(223)	**(16)**	(342)
Net change in non-cash working capital		**1,744**	432	**1,046**	538
Cash flows from operating activities		**7,010**	3,940	**17,115**	11,338
Financing activities					
(Repayment) issuance of bank credit facilities and commercial paper, net	8	**(59)**	712	**(25)**	692
Repayment of other long-term debt	8	**(441)**	(823)	**(441)**	(1,699)
Payment of lease liabilities	6	**(107)**	(87)	**(309)**	(253)
Issuance of common shares on exercise of stock options	11	**27**	40	**345**	191
Dividends on common shares		**(1,294)**	(1,228)	**(3,822)**	(3,645)
Purchase of common shares under Normal Course Issuer Bid	11	**(1,598)**	(309)	**(3,007)**	(1,155)
Cash flows used in financing activities		**(3,472)**	(1,695)	**(7,259)**	(5,869)
Investing activities					
Net expenditures on exploration and evaluation assets	4,17	**(14)**	(63)	**(125)**	(120)
Net expenditures on property, plant and equipment	5,17	**(1,869)**	(2,061)	**(6,341)**	(5,222)
Proceeds from long-term contract		**—**	—	**150**	—
Net change in non-cash working capital		**243**	(110)	**259**	(145)
Cash flows used in investing activities		**(1,640)**	(2,234)	**(6,057)**	(5,487)
Increase (decrease) in cash and cash equivalents		**1,898**	11	**3,799**	(18)
Opening cash balance prior to restatement for IFRS 9	2	**2,618**	102	**673**	131
Adjustment on adoption of IFRS 9	2	**—**	—	**44**	—
Cash and cash equivalents – beginning of period		**2,618**	102	**717**	131
Cash and cash equivalents – end of period		**$ 4,516**	$ 113	**$ 4,516**	$ 113
Interest paid on long-term debt		**$ 218**	$ 246	**$ 641**	$ 740
Income taxes paid, net		**$ 758**	$ 283	**$ 2,050**	$ 1,197

(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. In June 2026, the Company relocated its head and registered office to 400 - 4th Avenue S.W., Calgary, AB, T2P 0J4.

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

Critical Accounting Estimates and Judgements

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

2. CHANGE IN ACCOUNTING POLICIES

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

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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

The Company is continuing its assessment of the impact of adopting IFRS 18 on its consolidated financial statements and note disclosures. This assessment includes changes to the presentation of the consolidated balance sheets, consolidated statements of earnings, consolidated statements of cash flows, aggregation and disaggregation requirements, and identification and disclosure of MPMs. In addition, the Company is adapting its processes, where appropriate, to capture data required by IFRS 18 for inclusion in the consolidated financial statements and note disclosures. The Company will continue to evaluate the impacts and finalize implementation in advance of adoption on January 1, 2027.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2025	$ 2,594	$ —	$ —	$ 57	$ 2,651
Additions/Acquisitions, net	**145**	**—**	**—**	**—**	**145**
Transfers to property, plant and equipment	**(7)**	**—**	**—**	**—**	**(7)**
At September 30, 2026	**$ 2,732**	**$ —**	**$ —**	**$ 57**	**$ 2,789**

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2025	$ 92,896	$ 9,270	$ 5,316	$ 60,570	$ 503	$ 699	$ 169,254
Additions/Acquisitions, net	**4,458**	**9**	**399**	**1,605**	**5**	**30**	**6,506**
Transfers from exploration and evaluation assets	**7**	**—**	**—**	**—**	**—**	**—**	**7**
Derecognitions [1]	**(352)**	**(593)**	**—**	**(500)**	**—**	**(45)**	**(1,490)**
Foreign exchange adjustments and other	**—**	**329**	**196**	**—**	**—**	**—**	**525**
At September 30, 2026	**$ 97,009**	**$ 9,015**	**$ 5,911**	**$ 61,675**	**$ 508**	**$ 684**	**$ 174,802**
Accumulated depletion and depreciation							
At December 31, 2025	$ 65,940	$ 9,270	$ 4,035	$ 11,617	$ 246	$ 501	$ 91,609
Expense	**3,362**	**9**	**49**	**2,049**	**13**	**30**	**5,512**
Derecognitions [1]	**(352)**	**(593)**	**—**	**(500)**	**—**	**(45)**	**(1,490)**
Foreign exchange adjustments and other	**(5)**	**329**	**157**	**(3)**	**—**	**—**	**478**
At September 30, 2026	**$ 68,945**	**$ 9,015**	**$ 4,241**	**$ 13,163**	**$ 259**	**$ 486**	**$ 96,109**
Net book value							
At September 30, 2026	**$ 28,064**	**$ —**	**$ 1,670**	**$ 48,512**	**$ 249**	**$ 198**	**$ 78,693**
At December 31, 2025	$ 26,956	$ —	$ 1,281	$ 48,953	$ 257	$ 198	$ 77,645

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

During the first and second quarters of 2026, 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.

Peace River Crude Oil and NGLs, and Natural Gas Acquisitions

During the second quarter of 2026, the Company acquired certain producing and non-producing crude oil and NGLs, and natural gas assets for net cash consideration of $756 million, subject to final closing adjustments. Net assets acquired included exploration and evaluation assets of $33 million, and property, plant and equipment of $759 million. The Company also assumed asset retirement obligations of $31 million, and assumed net working capital of $5 million. No net deferred tax liabilities were recognized on this transaction.

During the first quarter of 2026, the Company acquired certain producing and non-producing crude oil and NGLs, and natural gas assets for net cash consideration of $761 million, subject to final closing adjustments. Net assets acquired included exploration and evaluation assets of $65 million, and property, plant and equipment of $796 million. The Company also assumed asset retirement obligations of $100 million. No net deferred tax liabilities were recognized on this transaction.

Pro Forma Information

As a result of the acquisition of assets in the Peace River area completed in the second quarter of 2026, revenue increased by approximately $116 million and net operating income (comprised of revenue, less production and transportation expense) increased by approximately $81 million for the period subsequent to the acquisition. Including the impact of depletion, depreciation and amortization, earnings before tax increased by approximately $60 million for the period subsequent to the acquisition.

As a result of the acquisition of assets in the Peace River area completed in the first quarter of 2026, revenue increased by approximately $343 million and net operating income (comprised of revenue, less production and transportation expense) increased by approximately $219 million for the period subsequent to the acquisition. Including the impact of depletion, depreciation and amortization, earnings before tax increased by approximately $157 million for the period subsequent to the acquisition.

If the acquisitions of assets in the Peace River area had been completed on January 1, 2026, the Company estimates that pro forma revenue would have increased by approximately $651 million and pro forma net operating income (comprised of revenue, less production and transportation expense) would have increased by approximately $437 million for the nine months ended September 30, 2026. Including the impact of depletion, depreciation and amortization, the Company estimates earnings before taxes would have increased by approximately $318 million for the nine months ended September 30, 2026. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have been achieved had the acquisitions actually occurred on January 1, 2026, or of future results. Pro forma results are based on historical information and reflect actual production in the period available for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition dates.

6. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2025	$ 2,199	$ 634	$ 43	$ 125	$ 3,001
Additions	**17**	**59**	**64**	**9**	**149**
Depreciation	**(121)**	**(150)**	**(26)**	**(18)**	**(315)**
Derecognitions	**—**	**—**	**(6)**	**—**	**(6)**
Foreign exchange and other	**4**	**(3)**	**3**	**(4)**	**—**
At September 30, 2026	**$ 2,099**	**$ 540**	**$ 78**	**$ 112**	**$ 2,829**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at September 30, 2026 were as follows:

	Sep 30 2026	Dec 31 2025
Lease liabilities	**$ 2,943**	$ 3,106
Less: current portion	**331**	373
	$ 2,612	$ 2,733

Total cash outflows for leases for the three months ended September 30, 2026, including payments related to short-term leases not reported as lease assets, were $486 million (three months ended September 30, 2025 – $376 million; nine months ended September 30, 2026 – $1,302 million; nine months ended September 30, 2025 – $1,108 million). Interest expense on leases for the three months ended September 30, 2026 was $32 million (three months ended September 30, 2025 – $16 million; nine months ended September 30, 2026 – $100 million; nine months ended September 30, 2025 – $47 million).

7. OTHER LONG-TERM ASSETS

	Sep 30 2026	Dec 31 2025
Long-term prepayments, contracts and other [1]	**$ 434**	$ 419
Prepaid cost of service tolls	**182**	229
Long-term inventory	**291**	291
	907	939
Less: current portion	**151**	70
	$ 756	$ 869

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

The Company has a 50% equity investment in NWRP. NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 barrels per day. The refinery's processing design capacity is 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. Bitumen feedstock throughput can exceed design capacity when asset reliability and operational performance support higher processing rates. 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 16). Sales of diesel and other refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 17).

The carrying value of the Company's interest in NWRP is $nil, and as at September 30, 2026, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $373 million (December 31, 2025 – $496 million). For the three months ended September 30, 2026, the Company's recovery of its share of unrecognized equity losses was $43 million (nine months ended September 30, 2026 – recovery of unrecognized equity losses of $134 million; three months ended September 30, 2025 – recovery of unrecognized equity losses of $21 million; nine months ended September 30, 2025 – recovery of unrecognized equity losses of $26 million). For the three and nine months ended September 30, 2026, the Company received partnership distributions of $11 million.

8. LONG-TERM DEBT

	Sep 30 2026	Dec 31 2025
Canadian dollar denominated debt, unsecured		
Medium-term notes	**$ 2,675**	$ 3,116
US dollar denominated debt, unsecured		
Bank credit facilities (September 30, 2026 – US$2,839 million; December 31, 2025 – US$2,860 million)	**4,029**	3,922
US dollar debt securities (September 30, 2026 – US$7,050 million; December 31, 2025 – US$7,050 million)	**10,004**	9,669
	16,708	16,707
Less: original issue discounts, net [1]	**12**	14
transaction costs [1] [2]	**63**	76
	16,633	16,617
Less: current portion of long-term debt [1] [2]	**1,772**	441
	$ 14,861	$ 16,176

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

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

Bank Credit Facilities and Commercial Paper

As at September 30, 2026, the Company had undrawn bank credit facilities of $5,421 million, and a fully drawn non-revolving term credit facility of $4,000 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit.

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

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

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

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

The Company's weighted average interest rate on bank credit facilities outstanding as at September 30, 2026 was 5.1% (September 30, 2025 – 4.9%), and on total long-term debt outstanding for the nine months ended September 30, 2026 was 5.0% (nine months ended September 30, 2025 – 5.0%).

As at September 30, 2026, letters of credit and other financial security aggregating to $959 million were outstanding (December 31, 2025 – $840 million).

Medium-Term Notes

During the third quarter of 2026, the Company repaid $441 million of 3.42% medium-term notes originally due December 1, 2026.

In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at September 30, 2026, the Company had $1,350 million remaining on its base shelf prospectus.

US Dollar Debt Securities

In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$4,500 million of debt securities in the United States, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at September 30, 2026, the Company had US$3,003 million remaining on its base shelf prospectus.

9. OTHER LONG-TERM LIABILITIES

		Sep 30 2026		Dec 31 2025
Asset retirement obligations	**$**	**9,621**	$	9,743
Lease liabilities (note 6)		**2,943**		3,106
Share-based compensation		**881**		433
Risk management (note 15)		**445**		65
Transportation and processing contracts		**173**		186
Other		**86**		68
		14,149		13,601
Less: current portion		**2,214**		1,665
	$	**11,935**	$	11,936

Asset Retirement Obligations

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

		Sep 30 2026		Dec 31 2025
Balance – beginning of period	**$**	**9,743**	$	8,607
Liabilities incurred		**31**		34
Liabilities acquired, net		**134**		489
Liabilities settled		**(677)**		(771)
Asset retirement obligation accretion		**294**		380
Revision of cost, inflation, and timing estimates [(1)]		**—**		1,233
Change in discount rates		**—**		(129)
Foreign exchange adjustments		**96**		(100)
Balance – end of period		**9,621**		9,743
Less: current portion		**1,302**		956
	$	**8,319**	$	8,787

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

Share-Based Compensation

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

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

		Sep 30 2026		Dec 31 2025
Balance – beginning of period	**$**	**433**	$	620
Share-based compensation expense		**879**		180
Cash payment for stock options surrendered and PSUs vested		**(177)**		(94)
Transferred to common shares		**(265)**		(273)
Other		**11**		—
Balance – end of period		**881**		433
Less: current portion		**548**		312
	$	**333**	$	121

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Nine Months Ended	
Expense (recovery)	**Sep 30 2026**	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Current corporate income tax – North America [1]	**$ 1,098**	$ 499	**$ 2,933**	$ 1,597
Current corporate income tax – North Sea	**(19)**	(37)	**(118)**	(108)
Current corporate income tax – Offshore Africa	**5**	—	**6**	5
Current PRT [2] – North Sea	**(66)**	(45)	**(180)**	(133)
Other taxes	**1**	2	**6**	7
Current income tax	**1,019**	419	**2,647**	1,368
Deferred corporate income tax	**(149)**	(143)	**67**	(130)
Deferred PRT [2] – North Sea	**38**	(389)	**(39)**	(362)
Deferred income tax	**(111)**	(532)	**28**	(492)
Income tax	**$ 908**	$ (113)	**$ 2,675**	$ 876

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

(2) Petroleum Revenue Tax.

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Nine Months Ended Sep 30, 2026	
Issued Common Shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**2,081,578**	**$ 11,421**
Issued upon exercise of stock options	**10,921**	**345**
Previously recognized liability on stock options exercised for common shares	**—**	**265**
Purchase of common shares under Normal Course Issuer Bid	**(46,975)**	**(269)**
Balance – end of period	**2,045,524**	**$ 11,762**

Dividends

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

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

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

Normal Course Issuer Bid

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

For the nine months ended September 30, 2026, the Company purchased 46,975,000 common shares at a weighted average price of $64.01 per common share for a total cost, including tax, of $3,055 million. Retained earnings were reduced by $2,786 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2026, up to and including November 3, 2026, the Company purchased 10,800,000 common shares at a weighted average price of $73.64 per common share for a total cost, including tax, of $811 million.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding as at September 30, 2026:

	Nine Months Ended Sep 30, 2026	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**54,734**	**$ 39.83**
Granted	**17,867**	**55.82**
Exercised for common shares	**(10,921)**	**31.60**
Surrendered for cash settlement	**(5,111)**	**39.33**
Forfeited	**(1,778)**	**44.04**
Outstanding – end of period	**54,791**	**$ 46.59**
Exercisable – end of period	**6,081**	**$ 40.11**

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.

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Sep 30 2026	Sep 30 2025
Derivative financial instruments designated as cash flow hedges	**$ 63**	$ 69
Foreign currency translation adjustment	**197**	166
	$ 260	$ 235

13. 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. As at September 30, 2026, the ratio was 20.5%.

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.

	Sep 30 2026	Dec 31 2025
Long-term debt	**$ 16,633**	$ 16,617
Less: cash and cash equivalents	**4,516**	673
Long-term debt, net	**$ 12,117**	$ 15,944
Total shareholders' equity	**$ 46,930**	$ 44,366
Debt to book capitalization	**20.5%**	26.4%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at September 30, 2026, the Company was in compliance with this covenant.

14. NET EARNINGS PER COMMON SHARE

		Three Months Ended		Nine Months Ended	
		Sep 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Weighted average common shares outstanding – basic (thousands of shares)		**2,058,063**	2,087,944	**2,073,395**	2,093,827
Effect of dilutive stock options (thousands of shares)		**13,850**	6,046	**12,269**	7,001
Weighted average common shares outstanding – diluted (thousands of shares)		**2,071,913**	2,093,990	**2,085,664**	2,100,828
Net earnings		**$ 2,997**	$ 600	**$ 8,848**	$ 5,517
Net earnings per common share	– basic	**$ 1.46**	$ 0.29	**$ 4.27**	$ 2.64
	– diluted	**$ 1.45**	$ 0.29	**$ 4.24**	$ 2.63

15. 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)	**Sep 30 2026**	Dec 31 2025
Balance – beginning of period	**$ (65)**	$ 5
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities [1] [2] [3] [4] [5]	**(380)**	(68)
Foreign exchange	**—**	(1)
Other comprehensive income	**—**	(1)
Balance – end of period	**(445)**	(65)
Less: current portion	**(8)**	(8)
	$ (437)	$ (57)

(1) Risk management liabilities are disclosed in note 9.

(2) In the third quarter of 2026, the Company entered into fixed price financial contracts to buy 25,000 MMBtu/d of natural gas at US$1.32 AECO for the period of August to December 2026, and 25,000 MMBtu/d of natural gas at US$1.74 AECO for the period of January to December 2027.

(3) 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.

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

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

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2026	Sep 30 2025	**Sep 30 2026**	Sep 30 2025
Net realized risk management loss (gain)	**$ 7**	$ 54	**$ 104**	$ (62)
Net unrealized risk management loss	**72**	160	**380**	148
	$ 79	$ 214	**$ 484**	$ 86

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:

	Sep 30, 2026	
	Carrying amount	Level 1 Fair Value
Fixed rate long-term debt [1] [2]	$ 12,604	$ 12,305

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

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

Embedded Derivative

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

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

The Company recognizes losses and gains on its risk management activities in the statements of earnings related to its natural gas embedded derivative, which are determined by the relative movements in fair value as compared to the prior period. For the three months ended September 30, 2026, the Company recognized an unrealized risk management loss of $70 million on the natural gas embedded derivative (nine months ended September 30, 2026 – unrealized loss of $380 million; three months ended September 30, 2025 – unrealized loss of $156 million; nine months ended September 30, 2025 – unrealized loss of $145 million). As at September 30, 2026, the fair value of the natural gas embedded derivative was a liability of $437 million (December 31, 2025 – $57 million liability).

The Level 3 fair value measurements of the embedded derivative could be materially impacted by a change in the discount rate and movements in natural gas prices. The following table summarizes the impacts to the fair value of the embedded derivative resulting from changes in the specified variable over the 15-year contract. These sensitivities as at September 30, 2026 are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities.

	JKM price		Discount rate	
	US$0.10/MMBtu increase	US$0.10/MMBtu decrease	1% increase	1% decrease
Fair value – increase/(decrease)	$ 55	$ (55)	$ (48)	$ 57

Financial Risk Factors

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

a) Market risk

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

Commodity price risk management

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

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. As at September 30, 2026, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

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

As at September 30, 2026, the Company had US$1,504 million of foreign currency forward contracts outstanding (December 31, 2025 – US$1,500 million), with original terms of up to 90 days, all of which were designated as derivatives held for trading (December 31, 2025 – US$1,500 million).

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and, where appropriate, ensuring that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at September 30, 2026, substantially all of the Company's accounts receivable were due within normal trade terms.

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

c) Liquidity risk

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

As at September 30, 2026, the maturity dates of the Company's financial liabilities were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 2,831	$ —	$ —	$ —
Accrued liabilities	$ 5,606	$ —	$ —	$ —
Long-term debt [1]	$ 1,772	$ 4,254	$ 2,875	$ 7,807
Other long-term liabilities [2] [3]	$ 339	$ 286	$ 614	$ 2,275
Interest and other financing expense [4]	$ 964	$ 734	$ 1,811	$ 3,342

(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, $331 million; one to less than two years, $286 million; two to less than five years, $614 million; and thereafter, $1,712 million.

(3) Includes a gross derivative liability of $563 million associated with the Company's natural gas embedded derivative. The gross liability is offset by a gross derivative asset of $126 million, resulting in a net liability of $437 million.

(4) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at September 30, 2026.

16. 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 September 30, 2026:

	Remaining 2026	2027	2028	2029	2030	Thereafter
Product transportation, purchases, and processing [1] [2]	$ 590	$ 2,280	$ 2,167	$ 2,014	$ 1,852	$ 19,882
North West Redwater Partnership service toll [3]	$ 23	$ 96	$ 97	$ 95	$ 95	$ 3,877
Offshore vessels and decommissioning equipment	$ 324	$ —	$ —	$ —	$ —	$ —
Field equipment and supplies	$ 52	$ 122	$ 121	$ 24	$ 24	$ 170
Office leases and other	$ 72	$ 67	$ 20	$ 20	$ 19	$ 179

(1) The Company's commitment under its product transportation agreement on the Trans Mountain Expansion pipeline reflects the toll approved by the Canada Energy Regulator in the third quarter of 2026. The Company's product transportation commitment was extended through 2046, with capacity increased to approximately 178,000 bbl/d.

(2) In the second quarter of 2026, the Company executed crude oil transportation agreements delivering between 150,000 bbl/d and 165,000 bbl/d of new pipeline capacity to US markets, with service currently expected to commence in the fourth quarter of 2028. These agreements are subject to certain conditions precedent, including a final investment decision by the project proponents and certain regulatory approvals. Accordingly, the related agreements will not be recognized as commitments until the completion of all conditions precedent. The transportation agreements have a term of 20 years and, if all conditions are met, will result in transportation payments of approximately $500 million to $550 million annually being added to the Company's commitments.

(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 $1,728 million of interest payable over the 40-year tolling period, ending in 2058 (note 7).

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.

17. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2026	2025	**2026**	2025	**2026**	2025	**2026**	2025	**2026**	2025	**2026**	2025	**2026**	2025	**2026**	2025
Segmented product sales																
Crude oil and NGLs [1]	**$ 7,055**	$ 4,724	**$ 19,871**	$ 14,685	**$ 63**	$ 28	**$ 181**	$ 236	**$ 107**	$ 21	**$ 133**	$ 131	**$ 7,225**	$ 4,773	**$ 20,185**	$ 15,052
Natural gas [1]	**496**	355	**1,765**	1,581	**3**	2	**8**	11	**3**	9	**5**	30	**502**	366	**1,778**	1,622
Other income and revenue	**145**	41	**298**	74	**—**	—	**—**	—	**—**	—	**—**	1	**145**	41	**298**	75
Total segmented product sales	**7,696**	5,120	**21,934**	16,340	**66**	30	**189**	247	**110**	30	**138**	162	**7,872**	5,180	**22,261**	16,749
Less: royalties	**(1,480)**	(710)	**(3,407)**	(1,978)	**—**	(1)	**—**	(1)	**(5)**	(1)	**(6)**	(7)	**(1,485)**	(712)	**(3,413)**	(1,986)
Segmented revenue	**6,216**	4,410	**18,527**	14,362	**66**	29	**189**	246	**105**	29	**132**	155	**6,387**	4,468	**18,848**	14,763
Segmented expenses																
Production	**1,017**	914	**3,041**	2,637	**78**	63	**209**	351	**45**	15	**76**	58	**1,140**	992	**3,326**	3,046
Blending and feedstock	**1,251**	883	**4,097**	3,393	**—**	—	**—**	—	**—**	—	**—**	—	**1,251**	883	**4,097**	3,393
Transportation	**531**	507	**1,594**	1,501	**3**	2	**10**	6	**—**	—	**—**	—	**534**	509	**1,604**	1,507
Depletion, depreciation and amortization [3]	**1,203**	1,188	**3,469**	3,365	**9**	1,285	**21**	1,358	**41**	20	**67**	92	**1,253**	2,493	**3,557**	4,815
Asset retirement obligation accretion	**55**	57	**164**	163	**21**	13	**62**	41	**1**	3	**4**	7	**77**	73	**230**	211
Risk management loss (commodity derivatives)	**72**	162	**388**	151	**—**	—	**—**	—	**—**	—	**—**	—	**72**	162	**388**	151
Gain on acquisition	**—**	—	**—**	(80)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(80)
Investment income	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**4,129**	3,711	**12,753**	11,130	**111**	1,363	**302**	1,756	**87**	38	**147**	157	**4,327**	5,112	**13,202**	13,043
Segmented earnings (loss)	**$ 2,087**	$ 699	**$ 5,774**	$ 3,232	**$ (45)**	$ (1,334)	**$ (113)**	$ (1,510)	**$ 18**	$ (9)	**$ (15)**	$ (2)	**$ 2,060**	$ (644)	**$ 5,646**	$ 1,720
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management loss (gain) (other)																
Foreign exchange loss (gain)																
Total non-segmented expenses																
Earnings before taxes																
Current income tax																
Deferred income tax																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream and Refining				Inter–segment Elimination and Other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2026	2025	**2026**	2025	**2026**	2025	**2026**	2025	**2026**	2025	**2026**	2025	**2026**	2025	**2026**	2025
Segmented product sales																
Crude oil and NGLs [1] [2]	**$ 6,810**	$ 5,255	**$ 20,490**	$ 15,157	**$ 26**	$ 24	**$ 72**	$ 68	**$ 208**	$ 416	**$ 703**	$ 797	**$ 14,269**	$ 10,468	**$ 41,450**	$ 31,074
Natural gas [1]	**—**	—	**—**	—	**—**	—	**—**	—	**29**	33	**88**	93	**531**	399	**1,866**	1,715
Other income and revenue	**332**	54	**657**	127	**365**	106	**988**	464	**1**	2	**2**	2	**843**	203	**1,945**	668
Total segmented product sales	**7,142**	5,309	**21,147**	15,284	**391**	130	**1,060**	532	**238**	451	**793**	892	**15,643**	11,070	**45,261**	33,457
Less: royalties	**(1,365)**	(842)	**(3,504)**	(2,318)	**—**	—	**—**	—	**—**	—	**—**	—	**(2,850)**	(1,554)	**(6,917)**	(4,304)
Segmented revenue	**5,777**	4,467	**17,643**	12,966	**391**	130	**1,060**	532	**238**	451	**793**	892	**12,793**	9,516	**38,344**	29,153
Segmented expenses																
Production	**1,322**	1,135	**3,850**	3,440	**77**	77	**233**	216	**12**	16	**38**	49	**2,551**	2,220	**7,447**	6,751
Blending and feedstock [2]	**940**	573	**2,688**	1,621	**221**	82	**632**	359	**231**	432	**763**	842	**2,643**	1,970	**8,180**	6,215
Transportation	**127**	206	**412**	537	**4**	3	**12**	38	**(4)**	3	**(7)**	(1)	**661**	721	**2,021**	2,081
Depletion, depreciation and amortization [3]	**791**	713	**2,257**	2,018	**4**	5	**13**	13	**—**	—	**—**	—	**2,048**	3,211	**5,827**	6,846
Asset retirement obligation accretion	**21**	22	**64**	65	**—**	—	**—**	—	**—**	—	**—**	—	**98**	95	**294**	276
Risk management loss (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**72**	162	**388**	151
Gain on acquisition	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(80)
Investment income	**—**	—	**—**	—	**(11)**	—	**(11)**	—	**—**	—	**—**	—	**(11)**	—	**(11)**	—
Total segmented expenses	**3,201**	2,649	**9,271**	7,681	**295**	167	**879**	626	**239**	451	**794**	890	**8,062**	8,379	**24,146**	22,240
Segmented earnings (loss)	**$ 2,576**	$ 1,818	**$ 8,372**	$ 5,285	**$ 96**	$ (37)	**$ 181**	$ (94)	**$ (1)**	$ —	**$ (1)**	$ 2	**$ 4,731**	$ 1,137	**$ 14,198**	$ 6,913
Non-segmented expenses																
Administration													**165**	152	**478**	455
Share-based compensation													**431**	63	**879**	97
Interest and other financing expense													**220**	93	**776**	589
Risk management loss (gain) (other)													**7**	52	**96**	(65)
Foreign exchange loss (gain)													**3**	290	**446**	(556)
Total non-segmented expenses													**826**	650	**2,675**	520
Earnings before taxes													**3,905**	487	**11,523**	6,393
Current income tax													**1,019**	419	**2,647**	1,368
Deferred income tax													**(111)**	(532)	**28**	(492)
Net earnings													**$ 2,997**	$ 600	**$ 8,848**	$ 5,517

(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 $1,258 million for revisions to abandonment and decommissioning costs in the North Sea for the three and nine months ended September 30, 2025.

Capital Expenditures [1]

	Nine Months Ended					
	Sep 30, 2026			Sep 30, 2025		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ 125**	**$ 13**	**$ 138**	$ 120	$ 85	$ 205
	125	**13**	**138**	120	85	205
Property, plant and equipment						
Exploration and Production						
North America	**4,293**	**(180)**	**4,113**	3,432	(34)	3,398
North Sea	**9**	**(593)**	**(584)**	16	1,003	1,019
Offshore Africa	**399**	**—**	**399**	309	—	309
	4,701	**(773)**	**3,928**	3,757	969	4,726
Oil Sands Mining and Upgrading	**1,605**	**(500)**	**1,105**	1,400	(646)	754
Midstream and Refining	**5**	**—**	**5**	6	—	6
Head Office	**30**	**(45)**	**(15)**	59	—	59
	6,341	**(1,318)**	**5,023**	5,222	323	5,545
	$ 6,466	**$ (1,305)**	**$ 5,161**	$ 5,342	$ 408	$ 5,750

(1) This table provides a reconciliation of capitalized costs, reported in note 4 and note 5, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

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

Segmented Assets

	Sep 30 2026	Dec 31 2025
Exploration and Production		
North America	**$ 39,643**	$ 33,462
North Sea	**955**	789
Offshore Africa	**1,802**	1,398
Other	**106**	35
Oil Sands Mining and Upgrading	**54,562**	54,699
Midstream and Refining	**1,379**	1,142
Head Office	**298**	305
	$ 98,745	$ 91,830

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

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

Interest coverage ratios (times) for the twelve month period ended September 30, 2026:	
Net earnings [1]	19.0x
Adjusted funds flow [2]	24.2x

(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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Dr. Grant E. Isaac
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President

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Chief Operating Officer, Exploration and Production

Jay E. Froc
Chief Operating Officer, Oil Sands

Ron K. Laing
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Victor C. Darel
Chief Financial Officer

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Senior Vice-President, Canadian Conventional Field Operations

Calvin J. Bast
Senior Vice-President, Production

Dwayne F. Giggs
Senior Vice-President, Exploration

Dean W. Halewich
Senior Vice-President, Safety, Risk Management and Innovation

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Senior Vice-President, Finance

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Mark A. Overwater
Vice-President, Marketing

Kyle G. Pisio
Vice-President, Drilling, Completions and Asset Retirement

Stephanie A. Graham
Corporate Secretary and Associate General Counsel, Canada

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

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

Stock Listing

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

Registrar and Transfer Agent

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