THIRD QUARTER REPORT

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2025 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2025 THIRD QUARTER RESULTS

Canadian Natural's President, Scott Stauth, commented on the Company's third quarter results, "Operations were strong in Q3/25 as we achieved record quarterly production volumes totaling approximately 1,620 MBOE/d, including records for both liquids and natural gas at 1,176 Mbbl/d and 2,668 MMcf/d respectively. We increased total corporate production by 19% or approximately 257,000 BOE/d from Q3/24 levels, reflecting both accretive acquisitions and organic growth achieved across our asset base over the last 12 months.

Our world class Oil Sands Mining and Upgrading assets continue to achieve strong operational performance as Q3/25 production averaged approximately 581,000 bbl/d of SCO, with strong utilization of 104% and industry leading operating costs of approximately $21 per barrel.

Subsequent to quarter end, we closed the AOSP swap with Shell Canada Limited and affiliates ("Shell") on November 1, 2025, with an effective date of March 1, 2025. Canadian Natural now owns and operates 100% of the Albian oil sands mines and associated reserves and retains a non-operated 80% interest in the Scotford Upgrader and Quest facilities. This generates additional cash flow and adds approximately 31,000 bbl/d of annual, zero decline bitumen production to our portfolio, driving long-term value creation for our shareholders. This swap also enhances our ability to integrate equipment and services across our mining operations, unlocking additional value through continuous improvement initiatives.

Additionally, we increased our annual 2025 corporate production guidance range to 1,560 MBOE/d to 1,580 MBOE/d, while our 2025 operating capital forecast remains unchanged at approximately $5.9 billion while executing additional activity on our increased asset base size."

Canadian Natural's Chief Financial Officer, Victor Darel, added "Our business model is robust and sustainable, underpinned by a strong balance sheet that provides flexibility through significant liquidity, totaling approximately $4.3 billion as at September 30, 2025. We closed accretive and opportunistic acquisitions in the quarter and remained at similar net debt levels when compared to Q2/25. These are excellent results, highlighting the free cash flow generating capability of our top tier asset base.

In Q3/25, we generated adjusted net earnings of $1.8 billion or $0.86 per share, and adjusted funds flow of $3.9 billion or $1.88 per share. We returned approximately $1.5 billion to our shareholders in the quarter, including $1.2 billion in dividends and $0.3 billion in share repurchases as we continue to execute on our free cash flow allocation policy."

THIRD QUARTER HIGHLIGHTS

- Generated net earnings of approximately $0.6 billion and adjusted net earnings from operations of approximately $1.8 billion.
- Generated adjusted funds flow of approximately $3.9 billion.
- Returns to shareholders totaled approximately $1.5 billion, comprised of $1.2 billion in dividends and $0.3 billion in share repurchases.
  - Year to date, up to and including November 5, 2025, the Company has returned a total of approximately $6.2 billion directly to shareholders through $4.9 billion in dividends and $1.3 billion in share repurchases.
  - 25 consecutive years of dividend growth with a CAGR of 21% over that time.
    - Subsequent to quarter end, declared a quarterly cash dividend on its common shares of $0.5875 per common share.
- Record quarterly corporate production of 1,620,261 BOE/d.
  - Significant total BOE production growth of approximately 257,000 BOE/d or 19% from Q3/24 levels reflects accretive acquisitions and organic growth achieved over the last 12 months.
  - Record quarterly liquids production of 1,175,604 bbl/d was achieved, an increase of approximately 154,000 bbl/d or 15% from Q3/24 levels.
    - Oil Sands Mining and Upgrading production was strong, averaging 581,136 bbl/d of SCO with upgrader utilization of 104% and industry leading operating costs of $21.29/bbl (US$15.46/bbl) in Q3/25.
- Canadian Natural continues to maintain a strong balance sheet and financial flexibility, with approximately $4.3 billion in liquidity(1) as at September 30, 2025. During Q3/25, the Company:
  - Repaid US$600 million of US dollar debt securities due in July 2025.
  - Received a new long-term investment grade credit rating of BBB+ from Fitch Ratings.
- Subsequent to quarter end, on November 1, 2025, Canadian Natural closed the AOSP swap with Shell. Canadian Natural now owns and operates 100% of the Albian oil sands mines and associated reserves and retains a non-operated 80% interest in the Scotford Upgrader and Quest facilities.
  - The transaction adds approximately 31,000 bbl/d of annual, zero decline bitumen production, providing additional cash flow and enabling more effective and efficient operations between the Horizon and Albian mines.
  - The swap did not include any cash consideration, with the exception of regular closing adjustments to reflect the effective date of March 1, 2025.
  - Following the close, Canadian Natural updated its 2025 capital and production guidance as follows:
    - 2025 production guidance range of 1,560 MBOE/d to 1,580 MBOE/d.
    - 2025 operating capital forecast remains unchanged at approximately $5.9 billion, following the $100 million reduction previously announced in May 2025.
      - As a result of strong operational execution and capital discipline, additional activity on a larger asset base, following opportunistic acquisitions in the year, has been executed with no incremental capital required.

(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, 2025 dated November 5, 2025 ("MD&A").

($ millions, except per common share amounts)		Three Months Ended **Sep 30 2025**	Jun 30 2025	Sep 30 2024	Nine Months Ended **Sep 30 2025**	Sep 30 2024
Net earnings		**$ 600**	$ 2,459	$ 2,266	**$ 5,517**	$ 4,968
Per common share	– basic	**$ 0.29**	$ 1.17	$ 1.07	**$ 2.64**	$ 2.33
	– diluted	**$ 0.29**	$ 1.17	$ 1.06	**$ 2.63**	$ 2.31
Adjusted net earnings from operations (1)		**$ 1,801**	$ 1,496	$ 2,071	**$ 5,733**	$ 5,437
Per common share	– basic (2)	**$ 0.86**	$ 0.71	$ 0.98	**$ 2.74**	$ 2.55
	– diluted (2)	**$ 0.86**	$ 0.71	$ 0.97	**$ 2.73**	$ 2.53
Cash flows from operating activities		**$ 3,940**	$ 3,114	$ 3,002	**$ 11,338**	$ 9,954
Adjusted funds flow (1)		**$ 3,920**	$ 3,262	$ 3,921	**$ 11,712**	$ 10,673
Per common share	– basic (2)	**$ 1.88**	$ 1.56	$ 1.85	**$ 5.59**	$ 5.01
	– diluted (2)	**$ 1.87**	$ 1.55	$ 1.84	**$ 5.57**	$ 4.97
Cash flows used in investing activities		**$ 2,234**	$ 1,941	$ 1,274	**$ 5,487**	$ 3,681
Net capital expenditures (3)		**$ 2,124**	$ 1,915	$ 1,349	**$ 5,342**	$ 4,083
Net capital expenditures (3), excluding net acquisition costs		**$ 1,318**	$ 1,691	$ 1,261	**$ 4,312**	$ 3,996
Abandonment expenditures		**$ 189**	$ 193	$ 204	**$ 570**	$ 495
Daily production, before royalties						
Natural gas (MMcf/d)		**2,668**	2,407	2,049	**2,510**	2,102
Crude oil and NGLs (bbl/d)		**1,175,604**	1,019,149	1,021,572	**1,122,859**	977,265
Equivalent production (BOE/d) (4)		**1,620,261**	1,420,358	1,363,086	**1,541,127**	1,327,593

(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) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2024. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A.
(4) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, or to compare the value ratio using current crude oil and natural gas prices since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

- Net earnings of $0.6 billion in Q3/25 reflected a non-cash recoverability charge of approximately $0.7 billion related to an increase in the estimate for future abandonment costs for the Ninian field and T-Block assets in the North Sea. Adjusted net earnings from operations, excluding the impact of the recoverability charge and unrealized foreign exchange and risk management activities, was strong at $1.8 billion in the quarter.

RETURNS TO SHAREHOLDERS

- Canadian Natural has a strong history of 25 consecutive years of growing its sustainable dividend with a CAGR of 21% over that time, demonstrating the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline reserves and asset base.
  - Returns to shareholders in Q3/25 were strong, totaling approximately $1.5 billion, comprised of $1.2 billion of dividends and $0.3 billion through the repurchase and cancellation of approximately 7.2 million common shares at a weighted average price of $43.12 per share.
  - Year to date, up to and including November 5, 2025, the Company has returned a total of approximately $6.2 billion directly to shareholders through $4.9 billion in dividends and $1.3 billion through the repurchase and cancellation of approximately 29.6 million common shares at a weighted average price of $42.92 per share.
  - Subsequent to quarter end, Canadian Natural declared a quarterly cash dividend on its common shares of $0.5875 per common share. The quarterly dividend will be payable on January 6, 2026 to shareholders of record at the close of business on December 12, 2025.

CORPORATE UPDATE

Canadian Natural is pleased to announce the appointment of Ms. Shelley A.M. Brown, CM, FCPA, FCA, ICD.D, O.C. to the Board of Directors of the Company and to the Audit Committee effective November 4, 2025. Ms. Brown is a Chartered Accountant who retired as a Senior Audit Partner with Deloitte after more than 35 years in public accounting. Ms. Brown has extensive experience working with public companies in the mining and manufacturing sectors and has over 30 years of experience working with both non-profit and public company boards including in the role of audit committee chair. Ms. Brown holds a Bachelor of Commerce from the University of Saskatchewan and is a Fellow of the Institutes of Chartered Accountants of Alberta, Saskatchewan, British Columbia and Ontario.

OPERATIONS REVIEW

North America Oil Sands Mining and Upgrading

	Three Months Ended			Nine Months Ended	
	Sep 30 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Synthetic crude oil production (bbl/d) (1)(2)	**581,136**	463,808	497,656	**546,635**	451,298

(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 581,136 bbl/d of SCO in Q3/25, an increase of 17% from Q3/24 levels, reflecting the additional working interest in AOSP acquired in December 2024 combined with effective and efficient operations.
  - Oil Sands Mining and Upgrading achieved strong upgrader utilization in Q3/25 of 104%.
  - Oil Sands Mining and Upgrading operating costs are industry leading, averaging $21.29/bbl (US$15.46/bbl) of SCO in Q3/25.
- Subsequent to quarter end, Canadian Natural closed the AOSP swap with Shell on November 1, 2025, with an effective date of March 1, 2025. Canadian Natural now owns and operates 100% of the Albian oil sands mines and associated reserves and retains a non-operated 80% interest in the Scotford Upgrader and Quest Carbon Capture and Storage facilities.
  - The transaction adds approximately 31,000 bbl/d of annual, zero decline bitumen production, providing additional cash flow and enabling more effective and efficient operations between the Horizon and Albian mines.
- At Horizon, the Company is progressing its Naphtha Recovery Unit Tailings Treatment ("NRUTT") project which targets incremental production of approximately 6,300 bbl/d of SCO, following mechanical completion in Q3/27.

North America Exploration and Production

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Bitumen production (bbl/d)	**274,752**	274,789	271,551	**278,046**	269,258
Net bitumen wells drilled	**11**	24	25	**53**	78
Net successful bitumen wells drilled	**11**	24	25	**53**	78
Success rate	**100%**	100%	100%	**100%**	100%

- Thermal in situ production averaged 274,752 bbl/d in Q3/25, comparable to Q3/24 levels.
  - Thermal in situ operating costs remain strong, averaging $10.35/bbl (US$7.52/bbl) in Q3/25, a decrease of 2% from Q3/24 levels of $10.52/bbl.
- Canadian Natural has significant thermal in situ facility processing capacity of 340,000 bbl/d, resulting in approximately 70,000 bbl/d of annual available capacity. The Company has decades of strong capital efficient drill to fill growth opportunities on its long life low decline thermal in situ assets, which we continue to develop in a disciplined manner to deliver safe and reliable thermal in situ production.

- At Primrose, the Company began drilling a Cyclic Steam Stimulation ("CSS") pad in Q3/25 with production targeted to come on in the second half of 2026.
- At Jackfish, the Company brought a Steam Assisted Gravity Drainage ("SAGD") pad on production in July 2025 as planned.
- At Kirby, the Company brought a five well-pair SAGD pad on production in late October 2025 as planned.
- At Pike, the Company tied the two recently drilled SAGD pads into the Jackfish facilities. These two SAGD pads are targeted to keep the Jackfish facilities at full capacity with the first pad targeted to come on production in January 2026 and the second pad targeted to come on production in Q2/26.

▪ 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 Steam to Oil Ratio ("SOR") and optimizing solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
  - At the commercial scale solvent SAGD pad at Kirby North, current SOR reductions and solvent recoveries are meeting expectations following recent workovers and optimizations.
  - At Primrose, the Company is continuing to operate its solvent enhanced oil recovery pilot in the steam flood area to optimize solvent efficiency and to further evaluate this commercial development opportunity.

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Crude oil and NGLs production (bbl/d)	**309,873**	271,022	228,221	**285,931**	234,537
Net crude oil wells drilled	**78**	57	59	**192**	130
Net successful crude oil wells drilled	**78**	57	58	**191**	129
Success rate	**100%**	100%	98%	**99%**	99%

▪ North America E&P liquids production, excluding thermal in situ, averaged 309,873 bbl/d in Q3/25, an increase of 36% or approximately 82,000 bbl/d from Q3/24 levels, reflecting opportunistic acquisitions and strong organic growth from heavy crude oil multilaterals, liquids-rich natural gas and light crude oil, partially offset by natural field declines.
  - Primary heavy crude oil production averaged 87,705 bbl/d in Q3/25, an increase of 14% from Q3/24 levels, reflecting strong drilling results from the Company's multilateral wells, partially offset by natural field declines.
    - Canadian Natural’s highly successful multilateral drilling program continues to unlock opportunity on our approximately 3 million net acres of high quality land throughout our primary heavy crude oil assets.
    - Operating costs in the Company's primary heavy crude oil operations averaged $16.46/bbl (US$11.95/bbl) in Q3/25, a decrease of 12% from Q3/24 levels, primarily as a result of higher production volumes and the increasing proportion of lower operating cost multilateral production.
  - Pelican Lake production averaged 42,070 bbl/d in Q3/25 a decrease of 7% from Q3/24 levels, reflecting planned maintenance in Q3/25 and the low natural field declines from this long life low decline asset.
    - Operating costs at Pelican Lake averaged $9.00/bbl (US$6.54/bbl) in Q3/25, an increase of 3% Q3/24 levels.
  - North America light crude oil and NGLs production averaged 180,098 bbl/d in Q3/25, an increase of 69% or approximately 74,000 bbl/d from Q3/24 levels, primarily reflecting production volumes from the acquisition of liquids-rich Duvernay assets in Q4/24, light crude oil Palliser Block assets in Q2/25 and the liquids-rich Montney assets in the Grande Prairie area in Q3/25.
    - Operating costs in the Company's North America light crude oil and NGLs operations averaged $12.91/bbl (US$9.38/bbl) in Q3/25, a decrease of 6% from Q3/24 levels of $13.73/bbl, primarily reflecting higher production volumes.
  - As previously announced, on July 2, 2025, Canadian Natural closed an acquisition of liquids-rich Montney assets located in the Grande Prairie area for approximately $750 million, which included production of approximately 32,000 BOE/d, including 12,500 bbl/d of NGLs.

North America Natural Gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Natural gas production (MMcf/d)	**2,658**	2,398	2,039	**2,498**	2,091
Net natural gas wells drilled	**17**	22	24	**58**	65
Net successful natural gas wells drilled	**17**	22	24	**58**	64
Success rate	**100%**	100%	100%	**100%**	98%

- North America natural gas production averaged 2,658 MMcf/d in Q3/25, an increase of 30% from Q3/24 levels, primarily reflecting opportunistic acquisitions and strong drilling results in the Company's liquids-rich natural gas assets, partially offset by natural field declines.
  - North America natural gas operating costs averaged $1.14/Mcf in Q3/25, a decrease of 7% from Q3/24 levels of $1.23/Mcf, primarily reflecting higher production volumes and cost efficiencies.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Crude oil production (bbl/d)	**9,843**	9,530	24,144	**12,247**	24,293
Natural gas production (MMcf/d)	**10**	9	10	**12**	11

- International E&P crude oil production volumes averaged 9,843 bbl/d in Q3/25, a decrease of 59% compared to Q3/24 levels. The decrease reflects temporary suspension of production at Baobab in Offshore Africa due to the planned refurbishment on its floating production storage and offloading ("FPSO") vessel, both planned and unplanned maintenance and planned decommissioning activities in the North Sea and natural field declines.
  - The annual production impact in 2025 from the planned Baobab FPSO refurbishment is targeted to be approximately 7,800 bbl/d, with production targeted to resume in Q2/26.

Drilling Activity

	Nine Months Ended			
	September 30, 2025		September 30, 2024	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil (1)	**252**	**244**	212	207
Natural gas	**73**	**58**	77	64
Dry	**1**	**1**	2	2
Subtotal	**326**	**303**	291	273
Stratigraphic test / service wells	**516**	**493**	460	394
Total	**842**	**796**	751	667
Success rate (excluding stratigraphic test / service wells)		**99%**		99%

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 303 net crude oil and natural gas wells in the first nine months of 2025, 30 more than in the first nine months of 2024.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Benchmark Commodity Prices					
WTI benchmark price (US$/bbl) [1]	**$ 64.95**	$ 63.71	$ 75.16	**$ 66.67**	$ 77.55
WCS heavy differential (discount) to WTI (US$/bbl) [1]	**$ (10.36)**	$ (10.19)	$ (13.51)	**$ (11.07)**	$ (15.46)
WCS heavy differential as a percentage of WTI (%) [1]	**16%**	16%	18%	**17%**	20%
Condensate benchmark price (US$/bbl)	**$ 63.12**	$ 63.42	$ 71.24	**$ 65.45**	$ 73.71
SCO price (US$/bbl) [1]	**$ 66.26**	$ 64.69	$ 76.51	**$ 66.66**	$ 76.42
SCO premium (discount) to WTI (US$/bbl) [1]	**$ 1.31**	$ 0.98	$ 1.35	**$ (0.01)**	$ (1.13)
AECO benchmark price (C$/GJ)	**$ 0.94**	$ 1.97	$ 0.77	**$ 1.61**	$ 1.35
Realized Prices					
Exploration & Production liquids realized price (C$/bbl) [2][3][4][5]	**$ 72.57**	$ 69.58	$ 79.15	**$ 74.06**	$ 78.67
SCO realized price (C$/bbl) [1][3][4][5]	**$ 87.85**	$ 87.22	$ 100.93	**$ 90.45**	$ 99.19
Natural gas realized price (C$/Mcf) [4]	**$ 1.49**	$ 2.58	$ 1.25	**$ 2.37**	$ 1.80

(1) West Texas Intermediate ("WTI"); Western Canadian Select ("WCS"); Synthetic Crude Oil ("SCO").
(2) Exploration & Production crude oil and NGLs average realized price excludes SCO.
(3) Pricing is net of blending and feedstock costs.
(4) Excludes risk management activities.
(5) Non-GAAP ratio. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A.

- Canadian Natural has a balanced and diverse product mix of SCO, light crude oil, NGLs, heavy crude oil, bitumen and natural gas, complemented with a balanced and diverse marketing strategy.
- Canadian Natural has total contracted crude oil transportation capacity of 256,500 bbl/d, with committed volumes to Canada’s west coast and to the United States Gulf Coast, being approximately 22% of 2025 forecasted liquids production. The egress supports Canadian Natural’s long-term sales strategy by targeting expanded refining markets, driving stronger netbacks while also reducing exposure to egress constraints.
- The North West Redwater refinery primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 38,434 bbl/d in Q3/25, reflecting the successful completion of the planned turnaround during the quarter.
- Canadian Natural has a diversified natural gas marketing strategy with the Company targeting in 2025 to use the equivalent of approximately 31% of forecasted natural gas production in its Oil Sands Mining and Upgrading and thermal operations, with approximately 38% targeted to be sold at AECO/Station 2 pricing, and approximately 31% targeted to be exported to other North American and international markets capturing higher natural gas prices, maximizing value.
- Canadian Natural has entered into a long-term natural gas supply agreement with Cheniere Energy, Inc. ("Cheniere") 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, subject to a number of conditions precedent including a positive final investment decision of the Sabine Pass Liquefaction Expansion Project by Cheniere.
  - 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 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 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, 2025 dated November 5, 2025.

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 management as required.

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

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

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

The Company's free cash flow for the three months ended September 30, 2025 and comparable periods is shown below:

	Three Months Ended		
($ millions)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024
Adjusted funds flow [(1)]	**$ 3,920**	$ 3,262	$ 3,921
Less: Dividends on common shares	**1,228**	1,233	1,118
Net capital expenditures[(2)]	**2,124**	1,915	1,349
Abandonment expenditures	**189**	193	204
Free cash flow	**$ 379**	$ (79)	$ 1,250

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, which are provided in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and nine months ended September 30, 2025 dated November 5, 2025.

(2) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2024. 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, 2025 dated November 5, 2025.

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 2025**	Jun 30 2025	Dec 31 2024	Sep 30 2024
Long-term debt	**$ 17,268**	$ 17,081	$ 18,819	$ 10,029
Less: cash and cash equivalents	**113**	102	131	721
Long-term debt, net	**$ 17,155**	$ 16,979	$ 18,688	$ 9,308

Breakeven WTI Price

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

Capital Budget

Capital budget is a forward-looking non-GAAP financial measure. The capital budget is based on net capital expenditures (non-GAAP financial measure) and includes acquisition capital related to a number of acquisitions for which agreements between parties have been reached as at the time of the Company's 2025 budget press release on January 9, 2025. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for more details on net capital expenditures.

The 2025 capital forecast reflects forecasted net capital expenditures, before abandonment expenditures related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea. The Company currently carries an Asset Retirement Obligation ("ARO") liability on its balance sheet for these forecasted future expenditures. Abandonment expenditures are reported before the impact of current income tax recoveries in Canada and the UK portion of the North Sea. The Company is eligible to recover interest on related to tax recoveries in the North Sea.

Capital Efficiency

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

ADVISORY

Special Note Regarding Forward-Looking Statements

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

The forward-looking statements are based on current expectations, estimates, and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance, or achievements of the Company to be materially different from any future results, performance, or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+"), the impact of conflicts in the Middle East and in Ukraine, increased inflation, and the risk of decreased economic activity resulting from a global recession) which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil, natural gas and NGLs prices; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; changes and 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; civil unrest and political uncertainty, including changes in government, actions of or against terrorists, insurgent groups, or other conflict including conflict between states; the ability of the Company to prevent and recover from a cyberattack, other cyber-related crime, and other cyber-related incidents; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling, and other equipment; ability of the Company to complete capital programs; the Company's ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting, or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in the mining, extracting, or upgrading the Company's bitumen products; availability and cost of financing; the Company's success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; changes to future abandonment and decommissioning costs, actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety, competition, environmental laws and regulations, and the impact of climate change initiatives on capital expenditures and production expenses); interpretations of applicable tax and competition laws and regulations; asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short-, medium-, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; the impact of legal proceedings to which the Company is party; and other circumstances affecting revenues and expenses.

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

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

Special Note Regarding Non-GAAP and Other Financial Measures

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

Special Note Regarding Common Share Split and Comparative Figures

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

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

On June 20, 2024, amendments to the *Competition Act* (Canada) came into force with the adoption of Bill C-59, *An Act to Implement Certain Provisions of the Fall Economic Statement* which impact environmental and climate disclosures by businesses. As a result of these amendments, certain public representations by a business regarding the benefits of the work it is doing to protect or restore the environment or mitigate the environmental and ecological causes or effects of climate change may violate the *Competition Act's* deceptive marketing practices provisions. These amendments include substantial financial penalties and, effective June 20, 2025, a private right of action which permits private parties to seek an order from the Competition Tribunal under the deceptive marketing practices provisions. Uncertainty surrounding the interpretation and enforcement of this legislation 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, 2025, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2024. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three and nine months ended September 30, 2025 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

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, bitumen (thermal oil), and SCO. 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, 2025 in relation to the comparable periods in 2024 and the second quarter of 2025. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2024, is available on SEDAR+ at www.sedarplus.ca, and on EDGAR at www.sec.gov. Information in such Annual Information Form and on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated November 5, 2025.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)		Three Months Ended Sep 30 2025	Jun 30 2025	Sep 30 2024	Nine Months Ended Sep 30 2025	Sep 30 2024
Product sales (1)		**$ 11,070**	$ 9,675	$ 10,401	**$ 33,457**	$ 30,445
Crude oil and NGLs		**$ 10,468**	$ 8,874	$ 9,943	**$ 31,074**	$ 28,703
Natural gas		**$ 399**	$ 600	$ 257	**$ 1,715**	$ 1,117
Net earnings		**$ 600**	$ 2,459	$ 2,266	**$ 5,517**	$ 4,968
Per common share	– basic	**$ 0.29**	$ 1.17	$ 1.07	**$ 2.64**	$ 2.33
	– diluted	**$ 0.29**	$ 1.17	$ 1.06	**$ 2.63**	$ 2.31
Adjusted net earnings from operations (2)		**$ 1,801**	$ 1,496	$ 2,071	**$ 5,733**	$ 5,437
Per common share	– basic (3)	**$ 0.86**	$ 0.71	$ 0.98	**$ 2.74**	$ 2.55
	– diluted (3)	**$ 0.86**	$ 0.71	$ 0.97	**$ 2.73**	$ 2.53
Cash flows from operating activities		**$ 3,940**	$ 3,114	$ 3,002	**$ 11,338**	$ 9,954
Adjusted funds flow (2)		**$ 3,920**	$ 3,262	$ 3,921	**$ 11,712**	$ 10,673
Per common share	– basic (3)	**$ 1.88**	$ 1.56	$ 1.85	**$ 5.59**	$ 5.01
	– diluted (3)	**$ 1.87**	$ 1.55	$ 1.84	**$ 5.57**	$ 4.97
Cash flows used in investing activities		**$ 2,234**	$ 1,941	$ 1,274	**$ 5,487**	$ 3,681
Net capital expenditures (4)		**$ 2,124**	$ 1,915	$ 1,349	**$ 5,342**	$ 4,083
Abandonment expenditures		**$ 189**	$ 193	$ 204	**$ 570**	$ 495

(1) Further details related to product sales are disclosed in note 15 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.

(4) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2024. 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, 2025 were $5,517 million compared with $4,968 million for the nine months ended September 30, 2024. Net earnings for the nine months ended September 30, 2025 included non-operating losses, net of tax, of $216 million compared with non-operating losses of $469 million for the nine months ended September 30, 2024 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on financing activities, the gain from investments, the gain on acquisition, a recoverability charge related to the increase in estimate of the future abandonment costs for the Ninian field and T-Block assets in the North Sea in the third quarter of 2025, and a recoverability charge related to the notice to withdraw from Block 11B/12B in South Africa in the second quarter of 2024. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2025 were $5,733 million compared with $5,437 million for the nine months ended September 30, 2024.

Net earnings for the third quarter of 2025 were $600 million compared with $2,266 million for the third quarter of 2024 and $2,459 million for the second quarter of 2025. Net earnings for the third quarter of 2025 included non-operating losses, net of tax, of $1,201 million compared with non-operating income of $195 million for the third quarter of 2024 and non-operating income of $963 million for the second quarter of 2025 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on financing activities, the gain on acquisition, and a recoverability charge related to the increase in estimate of the 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 2025 were $1,801 million compared with $2,071 million for the third quarter of 2024 and $1,496 million for the second quarter of 2025.

The increase in net earnings and adjusted net earnings from operations for the nine months ended September 30, 2025 from the nine months ended September 30, 2024 primarily reflected:

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

partially offset by:

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

The decrease in net earnings and adjusted net earnings from operations for the third quarter of 2025 from the third quarter of 2024 primarily reflected:

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

partially offset by:

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

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

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

partially offset by:

- lower realized natural gas pricing 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), gain on acquisition, and the gain from investments also contributed to fluctuations in net earnings from the comparable periods. These items are discussed in detail in the relevant sections of this MD&A.

The Company is progressing its abandonment and decommissioning activities in the North Sea, including the tendering and awarding of contracts for the Ninian South Platform. Following a competitive bidding process in 2025, cost estimates have come in higher than originally budgeted. As a result, the Company has reviewed and updated estimates for abandonment and decommissioning costs for its North Sea assets, including the Ninian Central and South Platforms and T-Block (comprising the Tiffany, Toni, and Thelma fields). In addition, based on current and forecasted economic conditions, including commodity pricing and market egress for T-Block volumes, the Company has determined that the T-Block assets are no longer economically viable. The Company is assessing alternatives for the potential acceleration of the T-Block decommissioning plan. As a result, at September 30, 2025, the Company recognized a non-cash charge of $695 million, comprised of additional abandonment costs for the Ninian field of $734 million, net of deferred tax recoveries of $359 million, and an additional charge of $524 million for T-Block, net of deferred tax recoveries of $204 million, relating to current and forecasted economic conditions. The Company's estimate of its asset retirement obligations, including its long-term abandonment projects in the North Sea and associated tax recoveries, are subject to revision in future periods as abandonment activities progress.

(1) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section 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, 2025 were $11,338 million compared with $9,954 million for the nine months ended September 30, 2024. Cash flows from operating activities for the third quarter of 2025 were $3,940 million compared with $3,002 million for the third quarter of 2024 and $3,114 million for the second quarter of 2025. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted related to the fluctuations in adjusted net earnings from operations, together with the impact of net changes in non-cash working capital.

Adjusted funds flow for the nine months ended September 30, 2025 was $11,712 million compared with $10,673 million for the nine months ended September 30, 2024. Adjusted funds flow for the third quarter of 2025 was $3,920 million compared with $3,921 million for the third quarter of 2024 and $3,262 million for the second quarter of 2025. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above related to the fluctuations in cash flows from operating activities, excluding the impact of the net change in non-cash working capital, abandonment expenditures, and movements in other long-term assets, including the unamortized cost of contributions to the Company's employee bonus program, interest on Petroleum Revenue Tax ("PRT") and corporate tax recoveries, and prepaid cost of service tolls.

Production Volumes

Crude oil and NGLs production before royalties for the third quarter of 2025 of 1,175,604 bbl/d increased 15% from 1,021,572 bbl/d for the third quarter of 2024 and increased 15% from 1,019,149 bbl/d for the second quarter of 2025. Natural gas production before royalties for the third quarter of 2025 of 2,668 MMcf/d increased 30% from 2,049 MMcf/d for the third quarter of 2024 and increased 11% from 2,407 MMcf/d for the second quarter of 2025. Total production before royalties for the third quarter of 2025 of 1,620,261 BOE/d increased 19% from 1,363,086 BOE/d for the third quarter of 2024 and increased 14% from 1,420,358 BOE/d for the second quarter of 2025. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production, before royalties" section of this MD&A.

Product Prices

In the Company's Exploration and Production segments, realized crude oil and NGLs prices averaged $72.57 per bbl for the third quarter of 2025, a decrease of 8% from $79.15 per bbl for the third quarter of 2024 and an increase of 4% from $69.58 per bbl for the second quarter of 2025. The realized natural gas price increased 19% to average $1.49 per Mcf for the third quarter of 2025 from $1.25 per Mcf for the third quarter of 2024 and decreased 42% from $2.58 per Mcf for the second quarter of 2025. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price decreased 13% to average $87.85 per bbl for the third quarter of 2025 from $100.93 per bbl for the third quarter of 2024 and was comparable with $87.22 per bbl for the second quarter of 2025. The Company's realized product pricing is reflective of the prevailing benchmark pricing. Crude oil and NGLs and natural gas prices are discussed in detail in the "Business Environment", "Realized Product Prices – Exploration and Production", and the "Realized Product Prices, Royalties and Transportation – Oil Sands Mining and Upgrading" sections of this MD&A.

Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense[(1)] averaged $13.18 per bbl for the third quarter of 2025, a decrease of 10% from $14.65 per bbl for the third quarter of 2024 and a decrease of 6% from $14.03 per bbl for the second quarter of 2025. Natural gas production expense[(1)] averaged $1.16 per Mcf for the third quarter of 2025, a decrease of 8% from $1.26 per Mcf for the third quarter of 2024 and an increase of 5% from $1.11 per Mcf for the second quarter of 2025. In the Oil Sands Mining and Upgrading segment, production expense[(1)] averaged $21.29 per bbl for the third quarter of 2025, comparable with $20.67 per bbl for the third quarter of 2024 and a decrease of 20% from $26.53 per bbl for the second quarter of 2025. Crude oil and NGLs and natural gas production expense is discussed in detail in the "Production Expense – Exploration and Production" and the "Production Expense – Oil Sands Mining and Upgrading" sections of this MD&A.

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

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

($ millions, except per common share amounts)		**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

($ millions, except per common share amounts)		Sep 30 2024		Jun 30 2024		Mar 31 2024		Dec 31 2023
Product sales [1]	$	10,401	$	10,622	$	9,422	$	10,679
Crude oil and NGLs	$	9,943	$	10,084	$	8,676	$	9,829
Natural gas	$	257	$	331	$	529	$	603
Net earnings	$	2,266	$	1,715	$	987	$	2,627
Net earnings per common share [2]								
– basic	$	1.07	$	0.80	$	0.46	$	1.22
– diluted	$	1.06	$	0.80	$	0.46	$	1.21

(1) Further details related to product sales for the three months ended September 30, 2025 and 2024 are disclosed in note 15 to the financial statements.

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

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, and impacts of ongoing tariff and trade uncertainty) on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the start-up of the Trans Mountain Expansion ("TMX") pipeline in the second quarter of 2024, the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America, and the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the International segments.
- **Natural gas pricing** – Fluctuations in both the demand for natural gas and inventory storage levels, the impact of third-party pipeline maintenance and outages, the impact of geopolitical and market uncertainties, the impact of seasonal conditions, 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 decline rates, the impact of turnarounds in the Oil Sands Mining and Upgrading segment, the impact and timing of acquisitions, including the acquisition of working interests in AOSP and Duvernay assets in the fourth quarter of 2024, the acquisition of assets in the Palliser Block in the second quarter of 2025, and the acquisition of assets in the Grande Prairie area in the third quarter of 2025, wildfires, and maintenance activities in the North America Exploration and Production segment. Sales volumes in the International segments also reflected fluctuations due to the timing of liftings, planned abandonment activities in the North Sea, and temporary suspension of production at Baobab in Offshore Africa for planned floating production storage and offloading vessel ("FPSO") maintenance.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's drilling program in the North America Exploration and Production segment, the impact and timing of acquisitions, including the acquisition of a working interest in the Duvernay assets in the fourth quarter of 2024, the acquisition of assets in the Palliser Block in the second quarter of 2025, and the acquisition of assets in the Grande Prairie area in the third quarter of 2025, natural field decline rates, the impact of seasonal conditions, and wildfires in the North America Exploration and Production segment.

- **Production expense –** Fluctuations primarily due to the impacts of the demand and cost for services, fluctuations in product mix and production volumes, seasonal conditions, carbon tax, fluctuating energy costs, inflationary cost pressures, cost optimizations across all segments, turnarounds in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Depletion, depreciation and amortization expense –** Fluctuations due to changes in sales volumes, timing of acquisitions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, the impact of turnarounds in the Oil Sands Mining and Upgrading segment, a recoverability charge at September 30, 2025 relating to an increase in estimate of future abandonment costs for the Ninian field and T-Block assets in the North Sea, recoverability charges at December 31, 2024 and December 31, 2023 relating to the increase in estimate of future abandonment costs for the planned decommissioning activities at the Ninian field in the North Sea, and a recoverability charge at June 30, 2024 relating to the notice to withdraw from Block 11B/12B in South 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, the impact of movements in benchmark interest rates on outstanding floating rate long-term debt, and interest on PRT and corporate tax recoveries.
- **Foreign exchange –** Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt and working capital.

BUSINESS ENVIRONMENT

Global crude oil benchmark pricing remained relatively stable through the third quarter of 2025, though continued to experience downward pressure from weaker demand outlooks amid ongoing tariff and trade uncertainty, and the impact of the unwinding of OPEC+ supply cuts. Additionally, near record non-OPEC+ production during the quarter reduced the impact of geopolitical supply uncertainty. Natural gas benchmark pricing declined in the third quarter of 2025, driven by increasing inventory levels primarily as a result of weaker US demand. In Canada, AECO benchmark pricing declined due to strong production in the Western Canadian Sedimentary Basin ("WCSB"), combined with third-party pipeline outages reducing export egress, and lower processing capacity than expected at LNG Canada.

In the first quarter of 2025, the US government announced tariffs on certain Canadian goods with countermeasures subsequently announced by the Canadian government. These trade measures have created market volatility which may continue to affect pricing received for the Company's products, increase the cost or reduce the availability of products in the Company's supply chain, and introduce additional foreign currency volatility. As of the date of this MD&A, the duration and impact of these trade actions remains uncertain, and any tariffs imposed or announced continue to evolve. The Company will continue to assess the impacts of any proposed or implemented tariffs on its business, financial condition, and results.

Liquidity

As at September 30, 2025, the Company had undrawn revolving bank credit facilities of $4,201 million. Including cash and cash equivalents, the Company had approximately $4,314 million in liquidity[(1)]. The Company also has certain other dedicated credit facilities supporting letters of credit. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity, and a flexible capital structure. Refer to the "Liquidity and Capital Resources" section of this MD&A for further details.

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

Benchmark Commodity Prices

(Average for the period)	Three Months Ended Sep 30 2025	Jun 30 2025	Sep 30 2024	Nine Months Ended Sep 30 2025	Sep 30 2024
WTI benchmark price (US$/bbl)	**$ 64.95**	$ 63.71	$ 75.16	**$ 66.67**	$ 77.55
Dated Brent benchmark price (US$/bbl)	**$ 69.08**	$ 67.78	$ 80.25	**$ 70.82**	$ 82.78
WCS Heavy Differential from WTI (US$/bbl)	**$ 10.36**	$ 10.19	$ 13.51	**$ 11.07**	$ 15.46
SCO price (US$/bbl)	**$ 66.26**	$ 64.69	$ 76.51	**$ 66.66**	$ 76.42
Condensate benchmark price (US$/bbl)	**$ 63.12**	$ 63.42	$ 71.24	**$ 65.45**	$ 73.71
NYMEX benchmark price (US$/MMBtu)	**$ 3.07**	$ 3.44	$ 2.16	**$ 3.39**	$ 2.10
AECO benchmark price (C$/GJ)	**$ 0.94**	$ 1.97	$ 0.77	**$ 1.61**	$ 1.35
US/Canadian dollar average exchange rate (US$)	**$ 0.7262**	$ 0.7225	$ 0.7332	**$ 0.7150**	$ 0.7351

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are directly impacted by fluctuations in foreign exchange rates resulting in product revenues being impacted by changes in Canadian dollar sales prices relative to the US dollar benchmark prices.

Crude oil sales contracts in North America are typically based on WTI benchmark pricing. WTI averaged US$66.67 per bbl for the nine months ended September 30, 2025, a decrease of 14% from US$77.55 per bbl for the nine months ended September 30, 2024. WTI averaged US$64.95 per bbl for the third quarter of 2025, a decrease of 14% from US$75.16 per bbl for the third quarter of 2024 and comparable with US$63.71 per bbl for the second quarter of 2025.

Crude oil sales contracts for the Company's International segments are typically based on Brent benchmark pricing, which is representative of international markets and overall global supply and demand. Brent averaged US$70.82 per bbl for the nine months ended September 30, 2025, a decrease of 14% from US$82.78 per bbl for the nine months ended September 30, 2024. Brent averaged US$69.08 per bbl for the third quarter of 2025, a decrease of 14% from US$80.25 per bbl for the third quarter of 2024 and comparable with US$67.78 per bbl for the second quarter of 2025.

The decrease in WTI and Brent benchmark pricing for the three and nine months ended September 30, 2025 from the comparable periods in 2024 reflected weaker global demand outlooks amid ongoing tariff and trade uncertainty, combined with increased OPEC+ supply and near record non-OPEC+ production.

The WCS Heavy Differential averaged US$11.07 per bbl for the nine months ended September 30, 2025, compared with US$15.46 per bbl for the nine months ended September 30, 2024. The WCS Heavy Differential averaged US$10.36 per bbl for the third quarter of 2025, compared with US$13.51 per bbl for the third quarter of 2024 and US$10.19 per bbl for the second quarter of 2025. The narrowing of the WCS Heavy Differential for the nine months ended September 30, 2025 from the nine months ended September 30, 2024 primarily reflected the start-up of the TMX pipeline in the second quarter of 2024, and strong US Gulf Coast heavy oil pricing. The narrowing of the WCS Heavy Differential for the third quarter of 2025 from the third quarter of 2024 primarily reflected higher refinery utilization further supported by strong US Gulf Coast heavy oil pricing.

The SCO price averaged US$66.66 per bbl for the nine months ended September 30, 2025, a decrease of 13% from US$76.42 per bbl for the nine months ended September 30, 2024. The SCO price averaged US$66.26 per bbl for the third quarter of 2025, a decrease of 13% from US$76.51 per bbl for the third quarter of 2024 and comparable with US$64.69 per bbl for the second quarter of 2025. The decrease in SCO pricing for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected weaker WTI benchmark pricing.

NYMEX benchmark pricing averaged US$3.39 per MMBtu for the nine months ended September 30, 2025, an increase of 61% from US$2.10 per MMBtu for the nine months ended September 30, 2024. NYMEX benchmark pricing averaged US$3.07 per MMBtu for the third quarter of 2025, an increase of 42% from US$2.16 per MMBtu for the third quarter of 2024 and a decrease of 11% from US$3.44 per MMBtu for the second quarter of 2025. The increase in NYMEX natural gas prices for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected lower US inventory levels in the first half of 2025, combined with higher LNG exports out of the US Gulf Coast. The decrease in NYMEX natural gas pricing for the third quarter of 2025 from the second quarter of 2025 primarily reflected increased inventory levels from strong US production and lower electricity demand, partially offset by increased LNG exports out of the US Gulf Coast.

AECO benchmark pricing averaged $1.61 per GJ for the nine months ended September 30, 2025, an increase of 19% from $1.35 per GJ for the nine months ended September 30, 2024. AECO benchmark pricing averaged $0.94 per GJ for the third quarter of 2025, an increase of 22% from $0.77 per GJ for the third quarter of 2024 and a decrease of 52% from $1.97 per GJ for the second quarter of 2025. The increase in AECO natural gas prices for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected higher NYMEX benchmark pricing, combined with increased exports out of the WCSB. The decrease in AECO natural gas pricing for the third quarter of 2025 from the second quarter of 2025 reflected increased inventory levels from strong production in the WCSB, lower processing capacity than expected at LNG Canada, and third-party pipeline outages reducing export egress.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**584,625**	545,811	499,772	**563,977**	501,674
North America – Oil Sands Mining and Upgrading [1]	**581,136**	463,808	497,656	**546,635**	451,298
International – Exploration and Production					
North Sea	**7,045**	7,761	10,958	**8,755**	11,560
Offshore Africa	**2,798**	1,769	13,186	**3,492**	12,733
Total International [2]	**9,843**	9,530	24,144	**12,247**	24,293
Total Crude oil and NGLs	**1,175,604**	1,019,149	1,021,572	**1,122,859**	977,265
Natural gas (MMcf/d) [3]					
North America	**2,658**	2,398	2,039	**2,498**	2,091
International					
North Sea	**2**	3	1	**3**	1
Offshore Africa	**8**	6	9	**9**	10
Total International	**10**	9	10	**12**	11
Total Natural gas	**2,668**	2,407	2,049	**2,510**	2,102
Total Barrels of oil equivalent (BOE/d)	**1,620,261**	1,420,358	1,363,086	**1,541,127**	1,327,593
Product mix					
Light and medium crude oil and NGLs	**12%**	11%	9%	**11%**	10%
Pelican Lake heavy crude oil	**3%**	3%	3%	**3%**	3%
Primary heavy crude oil	**5%**	6%	6%	**6%**	6%
Bitumen (thermal oil)	**17%**	19%	20%	**18%**	20%
Synthetic crude oil [1]	**36%**	33%	37%	**35%**	34%
Natural gas	**27%**	28%	25%	**27%**	27%
Percentage of product sales [1] [4] [5]					
Crude oil and NGLs	**96%**	93%	97%	**94%**	96%
Natural gas	**4%**	7%	3%	**6%**	4%

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

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

(3) Natural gas production volumes approximate sales volumes.

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

(5) Excluding Midstream and Refining revenue.

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**479,660**	472,329	399,397	**469,188**	402,381
North America – Oil Sands Mining and Upgrading [(1)]	**473,188**	397,052	408,120	**450,130**	370,547
International – Exploration and Production					
North Sea	**7,017**	7,746	10,925	**8,735**	11,531
Offshore Africa	**2,669**	1,692	12,496	**3,338**	12,104
Total International	**9,686**	9,438	23,421	**12,073**	23,635
Total Crude oil and NGLs	**962,534**	878,819	830,938	**931,391**	796,563
Natural gas (MMcf/d)					
North America	**2,615**	2,325	2,016	**2,430**	2,047
International					
North Sea	**2**	3	1	**3**	1
Offshore Africa	**8**	6	9	**8**	10
Total International	**10**	9	10	**11**	11
Total Natural gas	**2,625**	2,334	2,026	**2,441**	2,058
Total Barrels of oil equivalent (BOE/d)	**1,399,968**	1,267,787	1,168,599	**1,338,293**	1,139,622

(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, bitumen (thermal oil), SCO, and natural gas.

Crude oil and NGLs production before royalties for the nine months ended September 30, 2025 averaged 1,122,859 bbl/d, an increase of 15% from 977,265 bbl/d for the nine months ended September 30, 2024. Crude oil and NGLs production before royalties for the third quarter of 2025 averaged 1,175,604 bbl/d, an increase of 15% from 1,021,572 bbl/d for the third quarter of 2024 and an increase of 15% from 1,019,149 bbl/d for the second quarter of 2025. The increase in crude oil and NGLs production before royalties for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected the acquisition completed in December 2024, strong utilization in the Oil Sands Mining and Upgrading segment, and strong drilling results in the North America Exploration and Production segment. The increase in crude oil and NGLs production before royalties for the third quarter of 2025 from the second quarter of 2025 primarily reflected strong utilization in the Oil Sands Mining and Upgrading segment following the completion of the planned turnaround at the non-operated Scotford Upgrader ("Scotford") in the second quarter, combined with the acquisitions completed in the second and third quarters of 2025 in the North America Exploration and Production segment.

Annual crude oil and NGLs production for 2025 is now targeted to average between 1,137,000 bbl/d and 1,151,000 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, 2025 averaged 2,510 MMcf/d, an increase of 19% from 2,102 MMcf/d for the nine months ended September 30, 2024. Natural gas production before royalties for the third quarter of 2025 averaged 2,668 MMcf/d, an increase of 30% from 2,049 MMcf/d for the third quarter of 2024 and an increase of 11% from 2,407 MMcf/d for the second quarter of 2025. The increase in natural gas production before royalties for the three and nine months ended September 30, 2025 from the comparable periods primarily reflected the acquisitions completed in December 2024 and during the second and third quarters of 2025, combined with strong drilling results in the Company's liquids-rich natural gas assets, partially offset by natural field declines.

Annual natural gas production for 2025 is now targeted to average between 2,535 MMcf/d and 2,575 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, 2025 averaged 563,977 bbl/d, an increase of 12% from 501,674 bbl/d for the nine months ended September 30, 2024. North America crude oil and NGLs production before royalties for the third quarter of 2025 of 584,625 bbl/d increased 17% from 499,772 bbl/d for the third quarter of 2024 and increased 7% from 545,811 bbl/d for the second quarter of 2025. The increase in North America crude oil and NGLs production before royalties for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected the acquisition completed in December 2024, and strong drilling results from heavy oil multilaterals, liquids-rich natural gas, and light oil, partially offset by natural field declines. The increase in North America crude oil and NGLs production for the third quarter of 2025 from the second quarter of 2025 primarily reflected the acquisitions completed in the second and third quarters of 2025, partially offset by natural field declines.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 274,752 bbl/d for the third quarter of 2025, comparable with 271,551 bbl/d for the third quarter of 2024 and 274,789 bbl/d for the second quarter of 2025.

Pelican Lake heavy crude oil production before royalties for the third quarter of 2025 averaged 42,070 bbl/d, a decrease of 7% from 45,101 bbl/d for the third quarter of 2024 reflecting Pelican Lake's long life low decline production and planned maintenance activities. Pelican Lake heavy crude oil production before royalties for the third quarter of 2025 was comparable with 43,078 bbl/d for the second quarter of 2025.

North America natural gas production before royalties for the nine months ended September 30, 2025 averaged 2,498 MMcf/d, an increase of 19% from 2,091 MMcf/d for the nine months ended September 30, 2024. Natural gas production before royalties averaged 2,658 MMcf/d for the third quarter of 2025, an increase of 30% from 2,039 MMcf/d for the third quarter of 2024 and an increase of 11% from 2,398 MMcf/d for the second quarter of 2025. The increase in natural gas production before royalties for the three and nine months ended September 30, 2025 from the comparable periods primarily reflected the acquisitions completed in December 2024 and during the second and third quarters of 2025, and strong drilling results in the Company's liquids-rich natural gas assets, partially offset by natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the nine months ended September 30, 2025 averaged 546,635 bbl/d, an increase of 21% from 451,298 bbl/d for the nine months ended September 30, 2024. SCO production before royalties for the third quarter of 2025 averaged 581,136 bbl/d, an increase of 17% from 497,656 bbl/d for the third quarter of 2024 and an increase of 25% from 463,808 bbl/d for the second quarter of 2025. The increase in SCO production before royalties for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected the acquisition completed in December 2024, combined with high utilization. The increase in SCO production for the third quarter of 2025 from the second quarter of 2025 primarily reflected strong utilization following the completion of the planned turnaround at Scotford in the second quarter.

International – Exploration and Production

International crude oil and NGLs production before royalties for the nine months ended September 30, 2025 averaged 12,247 bbl/d, a decrease of 50% from 24,293 bbl/d for the nine months ended September 30, 2024. International crude oil and NGLs production before royalties for the third quarter of 2025 averaged 9,843 bbl/d, a decrease of 59% from 24,144 bbl/d for the third quarter of 2024 and comparable with 9,530 bbl/d for the second quarter of 2025. The decrease in International crude oil and NGLs production before royalties for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected the temporary suspension of production at Baobab in Offshore Africa due to planned maintenance on its FPSO, which is expected to return to service in the second quarter of 2026, planned North Sea abandonments conducted as part of the previously announced decommissioning plans, and natural field declines.

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Crude oil and NGLs ($/bbl) [1]					
Realized price [2]	**$ 72.57**	$ 69.58	$ 79.15	**$ 74.06**	$ 78.67
Transportation [3]	**6.93**	7.65	5.26	**6.99**	5.30
Realized price, net of transportation [2]	**65.64**	61.93	73.89	**67.07**	73.37
Royalties [4]	**13.10**	9.20	15.05	**12.26**	14.88
Production expense [5]	**13.18**	14.03	14.65	**14.32**	15.28
Netback [2]	**$ 39.36**	$ 38.70	$ 44.19	**$ 40.49**	$ 43.21
Natural gas ($/Mcf) [1]					
Realized price [6]	**$ 1.49**	$ 2.58	$ 1.25	**$ 2.37**	$ 1.80
Transportation [3]	**0.57**	0.59	0.63	**0.60**	0.62
Realized price, net of transportation	**0.92**	1.99	0.62	**1.77**	1.18
Royalties [4]	**0.02**	0.08	0.02	**0.07**	0.05
Production expense [5]	**1.16**	1.11	1.26	**1.16**	1.26
Netback [7]	**$ (0.26)**	$ 0.80	$ (0.66)	**$ 0.54**	$ (0.13)
Barrels of oil equivalent ($/BOE) [1]					
Realized price [2]	**$ 45.31**	$ 47.17	$ 50.36	**$ 49.09**	$ 51.29
Transportation [3]	**5.38**	5.94	4.67	**5.54**	4.70
Realized price, net of transportation [2]	**39.93**	41.23	45.69	**43.55**	46.59
Royalties [4]	**7.53**	5.58	9.05	**7.31**	8.99
Production expense [5]	**10.50**	10.95	11.81	**11.22**	12.16
Netback [2]	**$ 21.90**	$ 24.70	$ 24.83	**$ 25.02**	$ 25.44

(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 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Crude oil and NGLs ($/bbl) (1)					
North America (2)	**$ 72.35**	$ 69.30	$ 77.29	**$ 73.40**	$ 77.06
International average (3)	**$ 94.08**	$ 91.00	$ 109.41	**$ 102.18**	$ 112.14
North Sea (3)	**$ 90.19**	$ 90.63	$ 112.54	**$ 100.76**	$ 113.90
Offshore Africa (3)	**$ 99.90**	$ 95.92	$ 108.04	**$ 104.83**	$ 110.45
Crude oil and NGLs average (2)	**$ 72.57**	$ 69.58	$ 79.15	**$ 74.06**	$ 78.67
Natural gas ($/Mcf) (1) (3)					
North America	**$ 1.45**	$ 2.54	$ 1.19	**$ 2.32**	$ 1.75
International average	**$ 11.22**	$ 11.71	$ 12.67	**$ 12.76**	$ 12.22
North Sea	**$ 8.57**	$ 10.00	$ 11.28	**$ 12.70**	$ 10.79
Offshore Africa	**$ 11.87**	$ 12.47	$ 12.87	**$ 12.77**	$ 12.43
Natural gas average	**$ 1.49**	$ 2.58	$ 1.25	**$ 2.37**	$ 1.80
Average ($/BOE) (1) (2)	**$ 45.31**	$ 47.17	$ 50.36	**$ 49.09**	$ 51.29

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

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

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

North America

North America realized crude oil and NGLs prices decreased 5% to average $73.40 per bbl for the nine months ended September 30, 2025 from $77.06 per bbl for the nine months ended September 30, 2024. North America realized crude oil and NGLs prices averaged $72.35 per bbl for the third quarter of 2025, a decrease of 6% from $77.29 per bbl for the third quarter of 2024 and an increase of 4% from $69.30 per bbl for the second quarter of 2025. The decrease in North America realized crude oil and NGLs prices per bbl for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected lower WTI benchmark pricing, partially offset by a narrowing of the WCS Heavy Differential. The increase in North America realized crude oil and NGLs prices per bbl for the third quarter of 2025 from the second quarter of 2025 reflected prevailing benchmark pricing, and product sales mix. 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 marketing strategy and in the third quarter of 2025 contributed approximately 228,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 33% to average $2.32 per Mcf for the nine months ended September 30, 2025 from $1.75 per Mcf for the nine months ended September 30, 2024. North America realized natural gas prices increased 22% to average $1.45 per Mcf for the third quarter of 2025 from $1.19 per Mcf for the third quarter of 2024 and decreased 43% from $2.54 per Mcf for the second quarter of 2025. The increase in North America realized natural gas prices per Mcf for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected higher benchmark pricing. The decrease for the third quarter of 2025 from the second quarter of 2025 reflected lower benchmark and export pricing.

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

(Quarterly average)	Three Months Ended **Sep 30 2025**	 Jun 30 2025	 Sep 30 2024
Wellhead Price [1]			
Light and medium crude oil and NGLs ($/bbl)	**$ 66.29**	$ 63.96	$ 67.58
Pelican Lake heavy crude oil ($/bbl)	**$ 75.94**	$ 73.94	$ 84.02
Primary heavy crude oil ($/bbl)	**$ 75.55**	$ 72.88	$ 83.56
Bitumen (thermal oil) ($/bbl)	**$ 74.83**	$ 70.13	$ 78.26
Natural gas ($/Mcf)	**$ 1.45**	$ 2.54	$ 1.19

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

International

International realized crude oil and NGLs prices decreased 9% to average $102.18 per bbl for the nine months ended September 30, 2025 from $112.14 per bbl for the nine months ended September 30, 2024. International realized crude oil and NGLs prices decreased 14% to average $94.08 per bbl for the third quarter of 2025 from $109.41 per bbl for the third quarter of 2024 and increased 3% from $91.00 per bbl for the second quarter of 2025. Realized crude oil and NGLs prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, prevailing Brent benchmark prices and foreign exchange rates at the time of lifting.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 13.21**	$ 9.31	$ 15.72	**$ 12.51**	$ 15.46
International average	**$ 2.05**	$ 0.45	$ 4.02	**$ 1.71**	$ 2.96
North Sea	**$ 0.35**	$ 0.17	$ 0.33	**$ 0.17**	$ 0.27
Offshore Africa	**$ 4.60**	$ 4.19	$ 5.65	**$ 4.59**	$ 5.56
Crude oil and NGLs average	**$ 13.10**	$ 9.20	$ 15.05	**$ 12.26**	$ 14.88
Natural gas ($/Mcf) [1]					
North America	**$ 0.02**	$ 0.08	$ 0.01	**$ 0.07**	$ 0.04
Offshore Africa	**$ 0.55**	$ 0.57	$ 0.59	**$ 0.59**	$ 0.57
Natural gas average	**$ 0.02**	$ 0.08	$ 0.02	**$ 0.07**	$ 0.05
Average ($/BOE) [1]	**$ 7.53**	$ 5.58	$ 9.05	**$ 7.31**	$ 8.99

(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, 2025 and the comparable periods reflected movements in benchmark commodity prices, fluctuations in the WCS Heavy Differential and the impact of sliding scale royalty rates.

Crude oil and NGLs royalty rates[1] averaged approximately 17% of product sales for the nine months ended September 30, 2025 compared with 20% of product sales for the nine months ended September 30, 2024. Crude oil and NGLs royalty rates averaged approximately 18% of product sales for the third quarter of 2025 compared with 20% for the third quarter of 2024 and 13% for the second quarter of 2025. The decrease in royalty rates for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected prevailing benchmark pricing and the impact of sliding scale royalty rates. The increase in royalty rates for third quarter of 2025 from the second quarter of 2025 primarily reflected higher 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 3% of product sales for the nine months ended September 30, 2025 compared with 2% of product sales for the nine months ended September 30, 2024. Natural gas royalty rates averaged approximately 2% of product sales for the third quarter of 2025 compared with 1% for the third quarter of 2024 and 3% for the second quarter of 2025. The fluctuations in royalty rates for the three and nine months ended September 30, 2025 from the comparable periods 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, 2025 compared with 5% of product sales for the nine months ended September 30, 2024. Royalty rates as a percentage of product sales averaged approximately 5% for the third quarter of 2025 compared with 5% of product sales for the third quarter of 2024 and 5% for the second quarter of 2025. Royalty rates as a percentage of product sales reflected the timing of liftings, and the status of payout in the various fields.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2025	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 11.97**	$ 11.89	$ 12.36	**$ 12.17**	$ 13.17
International average	**$ 134.12**	$ 175.70	$ 52.04	**$ 106.02**	$ 59.04
North Sea	**$ 188.98**	$ 186.50	$ 120.92	**$ 145.38**	$ 98.49
Offshore Africa	**$ 52.17**	$ 29.38	$ 21.67	**$ 32.36**	$ 20.94
Crude oil and NGLs average	**$ 13.18**	$ 14.03	$ 14.65	**$ 14.32**	$ 15.28
Natural gas ($/Mcf) (1)					
North America	**$ 1.14**	$ 1.07	$ 1.23	**$ 1.12**	$ 1.23
International average	**$ 8.18**	$ 12.20	$ 6.24	**$ 9.02**	$ 6.13
North Sea	**$ 15.64**	$ 12.78	$ 9.61	**$ 12.34**	$ 8.60
Offshore Africa	**$ 6.32**	$ 11.94	$ 5.75	**$ 7.80**	$ 5.77
Natural gas average	**$ 1.16**	$ 1.11	$ 1.26	**$ 1.16**	$ 1.26
Average ($/BOE) (1)	**$ 10.50**	$ 10.95	$ 11.81	**$ 11.22**	$ 12.16

(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, 2025 averaged $12.17 per bbl, a decrease of 8% from $13.17 per bbl for the nine months ended September 30, 2024. North America crude oil and NGLs production expense for the third quarter of 2025 of $11.97 per bbl decreased 3% from $12.36 per bbl for the third quarter of 2024 and was comparable with $11.89 per bbl for the second quarter of 2025. The decrease in crude oil and NGLs production expense per bbl for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected lower fuel costs.

North America natural gas production expense for the nine months ended September 30, 2025 averaged $1.12 per Mcf, a decrease of 9% from $1.23 per Mcf for the nine months ended September 30, 2024. North America natural gas production expense for the third quarter of 2025 of $1.14 per Mcf decreased 7% from $1.23 per Mcf for the third quarter of 2024 and increased 7% from $1.07 per Mcf for the second quarter of 2025. The decrease in natural gas production expense per Mcf for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected higher production volumes. The increase in natural gas production expense per Mcf for the third quarter of 2025 from the second quarter of 2025 primarily reflected higher energy and service costs.

International

International crude oil and NGLs production expense for the nine months ended September 30, 2025 averaged $106.02 per bbl, an increase of 80% from $59.04 per bbl for the nine months ended September 30, 2024. International crude oil and NGLs production expense for the third quarter of 2025 of $134.12 per bbl increased 158% from $52.04 per bbl for the third quarter of 2024 and decreased 24% from $175.70 per bbl for the second quarter of 2025. The increase in crude oil and NGLs production expense per bbl for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected activities at Ninian in the pre-cessation period, the timing of liftings from various fields that have different cost structures, and the impact of foreign exchange. The decrease in crude oil and NGLs production expense per bbl for the third quarter of 2025 from the second quarter of 2025 primarily reflected the timing of liftings from various fields that have different cost structures.

ADJUSTED DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
North America	**$ 1,188**	$ 1,085	$ 924	**$ 3,365**	$ 2,821
North Sea	**1,285**	33	17	**1,358**	58
Offshore Africa	**20**	13	96	**92**	251
Depletion, depreciation and amortization	**$ 2,493**	$ 1,131	$ 1,037	**$ 4,815**	$ 3,130
Less: Recoverability charge (1) (2)	**1,258**	—	—	**1,258**	62
Adjusted depletion, depreciation and amortization (3)	**$ 1,235**	$ 1,131	$ 1,037	**$ 3,557**	$ 3,068
$/BOE (4)	**$ 13.08**	$ 12.94	$ 13.27	**$ 13.10**	$ 12.89

(1) The Company is progressing its abandonment and decommissioning activities in the North Sea, including the tendering and awarding of contracts for the Ninian South Platform. Following a competitive bidding process in 2025, cost estimates have come in higher than originally budgeted. As a result, the Company has reviewed and updated estimates for abandonment and decommissioning costs for its North Sea assets, including the Ninian Central and South Platforms and T-Block (comprising the Tiffany, Toni, and Thelma fields). In addition, based on current and forecasted economic conditions, including commodity pricing and market egress for T-Block volumes, the Company has determined that the T-Block assets are no longer economically viable. During the third quarter of 2025, the Company recognized a recoverability charge of $1,258 million in depletion, depreciation and amortization expense related to its North Sea assets.

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

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

(4) 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, 2025 averaged $13.10 per BOE, comparable with $12.89 per BOE for the nine months ended September 30, 2024. Adjusted depletion, depreciation and amortization expense for the third quarter of 2025 averaged $13.08 per BOE, comparable with $13.27 per BOE for the third quarter of 2024 and $12.94 per BOE for the second quarter of 2025.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
North America	**$ 57**	$ 53	$ 58	**$ 163**	$ 173
North Sea	**13**	14	16	**41**	48
Offshore Africa	**3**	2	2	**7**	6
Asset retirement obligation accretion	**$ 73**	$ 69	$ 76	**$ 211**	$ 227
$/BOE (1)	**$ 0.77**	$ 0.79	$ 0.97	**$ 0.78**	$ 0.96

(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, 2025 averaged $0.78 per BOE, a decrease of 19% from $0.96 per BOE for the nine months ended September 30, 2024. Asset retirement obligation accretion expense for the third quarter of 2025 averaged $0.77 per BOE, a decrease of 21% from $0.97 per BOE for the third quarter of 2024 and a decrease of 3% from $0.79 per BOE for the second quarter of 2025. The decrease in asset retirement obligation accretion expense per BOE for the three and nine months ended September 30, 2025 from the comparable periods in 2024 reflected the impact of changes in discount rate estimate revisions at December 31, 2024, combined with higher sales volumes in 2025, partially offset by revisions in cost and timing estimates at December 31, 2024. The decrease in asset retirement obligation accretion expense per BOE for the third quarter of 2025 from the second quarter of 2025 primarily reflected higher sales volumes.

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. SCO production averaged 581,136 bbl/d in the third quarter of 2025 primarily reflecting strong utilization in the Oil Sands Mining and Upgrading segment.

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

	Three Months Ended			Nine Months Ended	
($/bbl)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Realized SCO sales price (1)	**$ 87.85**	$ 87.22	$ 100.93	**$ 90.45**	$ 99.19
Bitumen value for royalty purposes (2)	**$ 68.06**	$ 64.57	$ 76.16	**$ 69.06**	$ 73.93
Bitumen royalties (3)	**$ 15.80**	$ 11.59	$ 17.71	**$ 15.49**	$ 17.24
Transportation (4)	**$ 3.86**	$ 3.73	$ 3.34	**$ 3.59**	$ 2.62

(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 $90.45 per bbl for the nine months ended September 30, 2025, a decrease of 9% from $99.19 per bbl for the nine months ended September 30, 2024. The realized SCO sales price averaged $87.85 per bbl for the third quarter of 2025, a decrease of 13% from $100.93 per bbl for the third quarter of 2024 and comparable with $87.22 per bbl for the second quarter of 2025. The decrease in realized SCO sales price per bbl for the three and nine months ended September 30, 2025 from the comparable periods in 2024 primarily reflected lower WTI benchmark pricing.

The fluctuations in bitumen royalties per bbl in any particular period reflect prevailing bitumen value for royalty purposes, and the impact of sliding scale royalty rates. The fluctuations in bitumen royalties per bbl for the three and nine months ended September 30, 2025 from the comparable periods primarily reflected the changes in average bitumen value for royalty purposes.

Transportation expense averaged $3.59 per bbl for the nine months ended September 30, 2025, an increase of 37% from $2.62 per bbl for the nine months ended September 30, 2024. Transportation expense averaged $3.86 per bbl for the third quarter of 2025, an increase of 16% from $3.34 per bbl for the third quarter of 2024 and an increase of 3% from $3.73 per bbl for the second quarter of 2025. The increase in transportation expense per bbl for the nine months ended September 30, 2025 from the nine months ended September 30, 2024 primarily reflected higher volumes shipped on the TMX pipeline in 2025. The increase in transportation expense per bbl for the third quarter of 2025 from the third quarter of 2024 and the second quarter of 2025 reflected the Company's commitments on egress pipelines, combined with higher volumes shipped on the TMX pipeline and to the US Gulf Coast.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Production expense, excluding natural gas costs	**$ 1,116**	$ 1,085	$ 917	**$ 3,336**	$ 2,810
Natural gas costs	**19**	35	18	**104**	92
Production expense	**$ 1,135**	$ 1,120	$ 935	**$ 3,440**	$ 2,902

	Three Months Ended			Nine Months Ended	
($/bbl)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Production expense, excluding natural gas costs (1)	**$ 20.93**	$ 25.71	$ 20.27	**$ 22.28**	$ 22.89
Natural gas costs (2)	**0.36**	0.82	0.40	**0.70**	0.75
Production expense (3)	**$ 21.29**	$ 26.53	$ 20.67	**$ 22.98**	$ 23.64
Sales volumes (bbl/d)	**579,209**	463,586	491,635	**548,197**	448,145

(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, 2025 averaged $22.98 per bbl, a decrease of 3% from $23.64 per bbl for the nine months ended September 30, 2024. Production expense for the third quarter of 2025 averaged $21.29 per bbl, comparable with $20.67 per bbl for the third quarter of 2024 and a decrease of 20% from $26.53 per bbl for the second quarter of 2025. The decrease in production expense per bbl for the nine months ended September 30, 2025 from the nine months ended September 30, 2024 primarily reflected higher production volumes from the acquisition of the additional 20% working interest in AOSP in December 2024. The decrease in production expense per bbl for the third quarter of 2025 from the second quarter of 2025 primarily reflected higher production volumes from strong utilization and lower fuel costs.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Depletion, depreciation and amortization	**$ 713**	$ 630	$ 556	**$ 2,018**	$ 1,637
$/bbl (1)	**$ 13.38**	$ 14.96	$ 12.27	**$ 13.49**	$ 13.33

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

Depletion, depreciation and amortization expense for the nine months ended September 30, 2025 averaged $13.49 per bbl, comparable with $13.33 per bbl for the nine months ended September 30, 2024. Depletion, depreciation and amortization expense for the third quarter of 2025 of $13.38 per bbl increased 9% from $12.27 per bbl for the third quarter of 2024 and decreased 11% from $14.96 per bbl for the second quarter of 2025. The increase in depletion, depreciation and amortization expense per bbl for the third quarter of 2025 from the third quarter of 2024 primarily reflected a higher depletable base due to asset additions, partially offset by higher sales volumes. The decrease in depletion, depreciation and amortization expense per bbl for the third quarter of 2025 from the second quarter of 2025 primarily reflected higher sales volumes in the third quarter.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended						Nine Months Ended			
($ millions, except per bbl amounts)		**Sep 30 2025**		Jun 30 2025		Sep 30 2024		**Sep 30 2025**		Sep 30 2024
Asset retirement obligation accretion	**$**	**22**	$	21	$	21	**$**	**65**	$	64
$/bbl [(1)]	**$**	**0.40**	$	0.51	$	0.46	**$**	**0.43**	$	0.51

(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, 2025 of $0.43 per bbl decreased 16% from $0.51 per bbl for the nine months ended September 30, 2024. Asset retirement obligation accretion expense for the third quarter of 2025 of $0.40 per bbl decreased 13% from $0.46 per bbl for the third quarter of 2024 and decreased 22% from $0.51 per bbl for the second quarter of 2025. The decrease in asset retirement obligation accretion expense per bbl for the three and nine months ended September 30, 2025 from the comparable periods primarily reflected the impact of higher sales volumes.

MIDSTREAM AND REFINING

	Three Months Ended						Nine Months Ended			
($ millions)		**Sep 30 2025**		Jun 30 2025		Sep 30 2024		**Sep 30 2025**		Sep 30 2024
Product sales										
Midstream activities	**$**	**24**	$	22	$	20	**$**	**68**	$	61
NWRP, refined product sales and other		**106**		137		191		**464**		620
Segmented revenue		**130**		159		211		**532**		681
Less:										
NWRP, refining toll		**70**		61		75		**199**		230
Midstream activities		**7**		5		3		**17**		15
Production expense		**77**		66		78		**216**		245
NWRP, feedstock costs		**82**		105		166		**359**		509
Transportation expenses		**3**		31		3		**38**		12
Depreciation		**5**		4		5		**13**		13
Segmented loss	**$**	**(37)**	$	(47)	$	(41)	**$**	**(94)**	$	(98)

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

NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 bbl/d. The refinery processes approximately 50,000 bbl/d of bitumen feedstock, including 12,500 bbl/d of bitumen feedstock for the Company (25% toll payer) and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058. Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment. For the third quarter of 2025, production of ultra-low sulphur diesel and other refined products averaged 38,434 BOE/d (9,608 BOE/d to the Company) (three months ended June 30, 2025 – 60,549 BOE/d; 15,137 BOE/d to the Company; three months ended September 30, 2024 – 72,109 BOE/d; 18,027 BOE/d to the Company), reflecting the successful completion of the planned turnaround in the third quarter, and the Company's 25% toll payer commitment.

As at September 30, 2025, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $483 million (December 31, 2024 – $509 million). For the three months ended September 30, 2025, the Company's recovery of its share of unrecognized equity losses was $21 million (three months ended June 30, 2025 – recovery of unrecognized equity losses of $24 million; nine months ended September 30, 2025 – recovery of unrecognized equity losses of $26 million; three months ended September 30, 2024 – recovery of unrecognized equity losses of $6 million; nine months ended September 30, 2024 – recovery of unrecognized equity losses of $45 million).

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Administration expense	**$ 152**	$ 151	$ 126	**$ 455**	$ 376
$/BOE (1)	**$ 1.03**	$ 1.17	$ 1.02	**$ 1.08**	$ 1.04
Sales volumes (BOE/d) (2)	**1,606,723**	1,423,321	1,342,508	**1,543,203**	1,316,989

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

(2) Total Company sales volumes.

Administration expense for the nine months ended September 30, 2025 of $1.08 per BOE increased 4% from $1.04 per BOE for the nine months ended September 30, 2024. Administration expense for the third quarter of 2025 of $1.03 per BOE was comparable with $1.02 per BOE for the third quarter of 2024 and decreased 12% from $1.17 per BOE for the second quarter of 2025. The increase in administration expense per BOE for the nine months ended September 30, 2025 from the nine months ended September 30, 2024 primarily reflected higher personnel costs, partially offset by higher overhead recoveries and higher sales volumes. The decrease in administration expense per BOE for the third quarter of 2025 from the second quarter of 2025 primarily reflected higher sales volumes.

SHARE-BASED COMPENSATION

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Share-based compensation expense (recovery)	**$ 63**	$ 8	$ (46)	**$ 97**	$ 235

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 $97 million of share-based compensation expense for the nine months ended September 30, 2025 primarily as a result of changes in the Company's share price, the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, and the impact of vested stock options exercised or surrendered during the period.

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions, except effective interest rate)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Interest and other financing expense	**$ 93**	$ 238	$ 154	**$ 589**	$ 450
Less: Interest (income) and other expense (1)	**(174)**	(7)	(5)	**(187)**	(34)
Interest expense on long-term debt and lease liabilities (1)	**$ 267**	$ 245	$ 159	**$ 776**	$ 484
Average current and long-term debt (2)	**$ 18,802**	$ 17,552	$ 11,130	**$ 18,500**	$ 11,431
Average lease liabilities (2)	**1,469**	1,382	1,511	**1,424**	1,526
Average long-term debt and lease liabilities (2)	**$ 20,271**	$ 18,934	$ 12,641	**$ 19,924**	$ 12,957
Average effective interest rate (3) (4)	**5.2%**	5.1%	4.9%	**5.1%**	4.9%
Interest and other financing expense ($/BOE) (5)	**$ 0.62**	$ 1.84	$ 1.24	**$ 1.40**	$ 1.25
Sales volumes (BOE/d) (6)	**1,606,723**	1,423,321	1,342,508	**1,543,203**	1,316,989

(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, 2025 increased 12% to $1.40 per BOE from $1.25 per BOE for the nine months ended September 30, 2024. Interest and other financing expense for the third quarter of 2025 decreased 50% to $0.62 per BOE from $1.24 per BOE for the third quarter of 2024 and decreased 66% from $1.84 per BOE for the second quarter of 2025. The increase in interest and other financing expense per BOE for the nine months ended September 30, 2025 from the nine months ended September 30, 2024 primarily reflected higher average debt levels, including higher floating rate debt levels, partially offset by higher sales volumes. The decrease in interest and other financing expense per BOE for the third quarter of 2025 from the third quarter of 2024 and second quarter of 2025 primarily reflected interest on the deferred PRT and corporate tax recoveries in the North Sea.

The Company's average effective interest rate for the three and nine months ended September 30, 2025 averaged 5.2% and 5.1%, respectively, an increase from the comparable periods in 2024, reflecting higher floating rate long-term debt held during 2025.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Foreign currency forward contracts	**$ 52**	$ (115)	$ (27)	**$ (83)**	$ 11
Foreign currency put options [1]	**—**	27	—	**23**	—
Natural gas financial instruments [2] [3] [4] [5]	**2**	(1)	6	**(2)**	11
Net realized loss (gain)	**54**	(89)	(21)	**(62)**	22
Foreign currency forward contracts	**—**	(19)	5	**(5)**	17
Foreign currency put options [1]	**—**	2	—	**—**	—
Natural gas embedded derivative [6]	**156**	(11)	—	**145**	—
Natural gas financial instruments [2] [3] [4] [5]	**4**	13	(5)	**8**	(4)
Net unrealized loss (gain)	**160**	(15)	—	**148**	13
Net loss (gain)	**$ 214**	$ (104)	$ (21)	**$ 86**	$ 35

(1) During 2025, the Company entered into foreign currency put options contracts. Further details are disclosed in note 13 to the financial statements.

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

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

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

(6) In the second quarter of 2025, the Company entered into a long-term natural gas supply agreement containing an embedded derivative. Further details are disclosed in note 13 to the financial statements.

During the nine months ended September 30, 2025, the Company recorded a net realized risk management gain of $62 million and a net realized risk management loss of $54 million for the third quarter of 2025.

The Company recorded a net unrealized loss of $148 million ($114 million after tax of $34 million) on its risk management activities for the nine months ended September 30, 2025, and a net unrealized loss of $160 million ($124 million after tax of $36 million) for the third quarter of 2025 (three months ended June 30, 2025 – unrealized gain of $15 million ($12 million after tax of $3 million); three months ended September 30, 2024 – $nil; nine months ended September 30, 2024 – unrealized loss of $13 million ($13 million after tax of $nil)).

Further details related to outstanding derivative financial instruments as at September 30, 2025 are disclosed in note 13 to the financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Net realized loss (gain)	**$ 21**	$ (142)	$ 30	**$ 121**	$ 129
Net unrealized loss (gain)	**269**	(661)	(148)	**(677)**	106
Net loss (gain) [1]	**$ 290**	$ (803)	$ (118)	**$ (556)**	$ 235

(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, 2025 was primarily related to the exchange rate fluctuations on the settlement of US dollar debt, and on the settlement of working capital items denominated in US dollars. The net unrealized foreign exchange gain for the nine months ended September 30, 2025 was primarily related to the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at September 30, 2025 was US$0.7191 (June 30, 2025 – US$0.7341, September 30, 2024 – US$0.7405).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended Sep 30 2025	Jun 30 2025	Sep 30 2024	Nine Months Ended Sep 30 2025	Sep 30 2024
North America [1]	**$ 499**	$ 529	$ 433	**$ 1,597**	$ 1,393
North Sea	**(37)**	(45)	(12)	**(108)**	(30)
Offshore Africa	**—**	—	12	**5**	22
Current PRT – North Sea	**(45)**	(49)	(47)	**(133)**	(67)
Other taxes	**2**	3	3	**7**	(8)
Current income tax	**419**	438	389	**1,368**	1,310
Deferred corporate income tax	**(143)**	(106)	120	**(130)**	148
Deferred PRT – North Sea	**(389)**	18	34	**(362)**	47
Deferred income tax	**(532)**	(88)	154	**(492)**	195
Income tax	**$ (113)**	$ 350	$ 543	**$ 876**	$ 1,505
Earnings before taxes	**$ 487**	$ 2,809	$ 2,809	**$ 6,393**	$ 6,473
Effective tax rate on net earnings [2]	**(23)%**	12%	19%	**14%**	23%

($ millions, except effective tax rates)	Three Months Ended Sep 30 2025	Jun 30 2025	Sep 30 2024	Nine Months Ended Sep 30 2025	Sep 30 2024
Income tax	**$ (113)**	$ 350	$ 543	**$ 876**	$ 1,505
Tax effect on non-operating items [3]	**603**	(1)	1	**607**	32
Current PRT – North Sea	**45**	49	47	**133**	67
Deferred PRT – North Sea	**(31)**	(18)	(34)	**(58)**	(47)
Other taxes	**(2)**	(3)	(3)	**(7)**	8
Effective tax on adjusted net earnings	**$ 502**	$ 377	$ 554	**$ 1,551**	$ 1,565
Adjusted net earnings from operations [4]	**$ 1,801**	$ 1,496	$ 2,071	**$ 5,733**	$ 5,437
Adjusted net earnings from operations, before taxes	**$ 2,303**	$ 1,873	$ 2,625	**$ 7,284**	$ 7,002
Effective tax rate on adjusted net earnings from operations [5] [6]	**22%**	20%	21%	**21%**	22%

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

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

(3) Includes the net income tax effect on PSUs, certain stock options, unrealized risk management, a recoverability charge related to the increase in estimate of the future abandonment costs for the Ninian field and T-Block assets in the North Sea in the third quarter of 2025, and a recoverability charge related to the notice to withdraw from Block 11B/12B in South Africa in the second quarter of 2024.

(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, 2025 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings.

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, 2025 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 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Exploration and Production					
Exploration and Evaluation Assets					
Net expenditures	**$ 18**	$ 5	$ 8	**$ 42**	$ 73
Net property acquisitions	**45**	46	—	**78**	—
Total Exploration and Evaluation Assets	**63**	51	8	**120**	73
Property, Plant and Equipment					
Net property acquisitions	**761**	178	88	**970**	89
Well drilling, completion and equipping	**499**	558	469	**1,593**	1,360
Production and related facilities	**365**	407	387	**1,162**	995
Other	**13**	16	14	**32**	39
Total Property, Plant and Equipment	**1,638**	1,159	958	**3,757**	2,483
Total Exploration and Production	**1,701**	1,210	966	**3,877**	2,556
Oil Sands Mining and Upgrading					
Project costs	**76**	96	55	**227**	240
Sustaining capital	**312**	406	302	**934**	1,109
Turnaround costs	**13**	174	12	**233**	137
Net property dispositions	**—**	—	—	**—**	(2)
Other	**2**	2	3	**6**	5
Total Oil Sands Mining and Upgrading	**403**	678	372	**1,400**	1,489
Midstream and Refining	**2**	2	3	**6**	10
Head Office	**18**	25	8	**59**	28
Net capital expenditures	**$ 2,124**	$ 1,915	$ 1,349	**$ 5,342**	$ 4,083
Abandonment expenditures	**$ 189**	$ 193	$ 204	**$ 570**	$ 495
By Segment					
North America	**$ 1,606**	$ 1,110	$ 896	**$ 3,552**	$ 2,401
North Sea	**5**	8	29	**16**	36
Offshore Africa	**90**	92	41	**309**	119
Oil Sands Mining and Upgrading	**403**	678	372	**1,400**	1,489
Midstream and Refining	**2**	2	3	**6**	10
Head Office	**18**	25	8	**59**	28
Net capital expenditures	**$ 2,124**	$ 1,915	$ 1,349	**$ 5,342**	$ 4,083

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

(2) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2024. 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 $5,342 million for the nine months ended September 30, 2025 compared with $4,083 million for the nine months ended September 30, 2024. Net capital expenditures were $2,124 million for the third quarter of 2025 compared with $1,349 million for the third quarter of 2024 and $1,915 million for the second quarter of 2025.

In addition, the Company reported abandonment expenditures of $570 million for the nine months ended September 30, 2025 compared with $495 million for the nine months ended September 30, 2024. Abandonment expenditures were $189 million for the third quarter of 2025 compared with $204 million for the third quarter of 2024 and $193 million for the second quarter of 2025.

2025 Capital Budget

On January 9, 2025, the Company announced its 2025 operating capital budget*(1)* targeted at approximately $6,015 million, which comprises capital related to a number of acquisitions, including the acquisitions completed in the second quarter of 2025. With this capital, the Company is targeting near-term production growth in 2025 and mid- and long-term production and capacity growth in 2026 and beyond. In addition, the Company has approved approximately $135 million of capital, consisting of $90 million related to carbon capture and $45 million related to a one-time office move scheduled to take place through 2026. The Company targets $787 million in abandonment expenditures for 2025. On May 7, 2025, the 2025 total capital budget was reduced by $100 million to $6,050 million, excluding abandonment expenditures. On November 3, 2025, the Company revised its 2025 production guidance to between 1,560 MBOE/d and 1,580 MBOE/d.

In July 2025, the Company acquired certain producing and non-producing NGLs and natural gas assets in the Grande Prairie area in the North America Exploration and Production segment for cash consideration of $752 million, subject to final closing adjustments. The 2025 capital budget did not include capital related to the Grande Prairie, and other small acquisitions completed in the third quarter of 2025.

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 2025 capital budget constitutes forward-looking statements and is based on net capital expenditures. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Drilling Activity (1) (2)

	Three Months Ended			Nine Months Ended	
(number of net wells)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Net successful crude oil wells (3)	**89**	81	83	**244**	207
Net successful natural gas wells	**17**	22	24	**58**	64
Dry wells	**—**	—	1	**1**	2
Total	**106**	103	108	**303**	273
Success rate	**100%**	100%	99%	**99%**	99%

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

(2) Excludes stratigraphic and service wells.

(3) Includes bitumen wells.

North America

During the third quarter of 2025, the Company drilled 17 net natural gas wells, 58 net primary heavy crude oil wells, 4 net Pelican Lake heavy crude oil wells, 11 net bitumen (thermal oil) wells and 16 net light crude oil wells.

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

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	Sep 30 2025	Jun 30 2025	Dec 31 2024	Sep 30 2024
Adjusted working capital (1)	**$ (303)**	$ 102	$ 174	$ 365
Long-term debt, net (2)	**$ 17,155**	$ 16,979	$ 18,688	$ 9,308
Shareholders' equity	**$ 40,461**	$ 41,298	$ 39,468	$ 39,897
Debt to book capitalization (2)	**29.8%**	29.1%	32.1%	18.9%
After-tax return on average capital employed (3)	**12.8%**	16.3%	12.7%	15.9%

(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, 2025, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities, and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt are dependent on factors discussed in the "Business Environment" section of this MD&A and in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2024. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings, as determined by independent rating agencies and market conditions.

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

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

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers, and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;
- Actively managing the allocation of capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments, and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
  - During the first quarter of 2025, the Company extended its $500 million revolving credit facility originally maturing February 2026 to June 2027.
  - 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.
  - In July 2023, 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 expired in August 2025. 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.
  - During the third quarter of 2025, the Company repaid US$600 million of 2.05% US dollar debt securities due July 2025.
  - During the first quarter of 2025, the Company repaid US$600 million of 3.90% US dollar debt securities due February 2025.

- In July 2023, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expired in August 2025. 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.
- In October 2025, the Company filed a prospectus supplement to the base shelf prospectus. Under the prospectus supplement, up to US$1,500 million of the registered debt securities may be issued in exchange for up to US$1,500 million of the Company's outstanding restricted 5.00% US dollar debt securities due December 2029 and 5.40% US dollar debt securities due December 2034. Any notes issued under such exchange will not be subject to transfer restrictions and will not result in a change in the current level of indebtedness.

As at September 30, 2025, the Company had undrawn revolving bank credit facilities of $4,201 million, and a fully drawn non-revolving term credit facility of $4,000 million. Including cash and cash equivalents, the Company had approximately $4,314 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. As at September 30, 2025, the Company had $829 million drawn under its commercial paper program and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

Long-term debt, net was $17,155 million as at September 30, 2025 (December 31, 2024 – $18,688 million), resulting in a debt to book capitalization ratio of 29.8% (December 31, 2024 – 32.1%); this ratio was within the 25% to 45% internal range utilized by management. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at September 30, 2025, the Company was in compliance with this covenant.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt as at September 30, 2025 are discussed in note 6 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, 2025, the maturity dates of certain financial liabilities, including long-term debt and other long-term liabilities and related interest payments, were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt [(1)]	$ 829	$ 3,047	$ 6,345	$ 7,127
Other long-term liabilities [(2)]	$ 227	$ 175	$ 417	$ 779
Interest and other financing expense [(3)]	$ 966	$ 938	$ 1,634	$ 3,114

(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, $224 million; one to less than two years, $175 million; two to less than five years, $417 million; and thereafter, $634 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at September 30, 2025.

Share Capital

As at September 30, 2025, there were 2,085,082,000 common shares outstanding (December 31, 2024 – 2,102,996,000 common shares) and 57,326,000 stock options outstanding (December 31, 2024 – 50,806,000 stock options). As at November 4, 2025, the Company had 2,083,107,000 common shares outstanding and 56,671,000 stock options outstanding.

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

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

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

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

For the nine months ended September 30, 2025, the Company purchased 26,980,000 common shares at a weighted average price of $42.81 per common share for a total cost, including tax, of $1,170 million. Retained earnings were reduced by $1,025 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2025, up to and including November 4, 2025, the Company purchased 2,500,000 common shares at a weighted average price of $44.03 per common share for a total cost, including tax, of $112 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, 2025:

($ millions)	Remaining 2025	2026	2027	2028	2029	Thereafter
Product transportation, purchases, and processing [1]	$ 602	$ 2,380	$ 2,253	$ 2,107	$ 2,004	$ 19,595
North West Redwater Partnership service toll [2]	$ 35	$ 117	$ 97	$ 98	$ 97	$ 4,018
Offshore vessels and equipment	$ 94	$ —	$ —	$ —	$ —	$ —
Field equipment and power	$ 29	$ 32	$ 29	$ 28	$ 27	$ 216
Other	$ 31	$ 119	$ 19	$ 19	$ 18	$ 195

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

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $1,882 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 that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the Company's annual MD&A and audited consolidated financial statements for the year ended December 31, 2024.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the nine months ended September 30, 2025 that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting. Due to inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A includes references to non-GAAP and other financial measures as defined in NI 52-112. These financial measures are used by the Company to evaluate its financial performance, financial position, and cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS 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 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Net earnings	**$ 600**	$ 2,459	$ 2,266	**$ 5,517**	$ 4,968
Share-based compensation, net of tax (1)	**59**	6	(48)	**87**	218
Unrealized risk management loss (gain), net of tax (2)	**124**	(12)	1	**114**	13
Unrealized foreign exchange loss (gain), net of tax (3)	**269**	(661)	(148)	**(677)**	106
Realized foreign exchange loss (gain) on financing activities, net of tax (4)	**54**	(216)	—	**77**	135
Gain from investments, net of tax	**—**	—	—	**—**	(50)
Gain on acquisition, net of tax (5)	**—**	(80)	—	**(80)**	—
Recoverability charge, net of tax (6) (7)	**695**	—	—	**695**	47
Non-operating items, net of tax	**1,201**	(963)	(195)	**216**	469
Adjusted net earnings from operations	**$ 1,801**	$ 1,496	$ 2,071	**$ 5,733**	$ 5,437

(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, 2025 was an expense of $63 million (three months ended June 30, 2025 – $8 million expense, three months ended September 30, 2024 – $46 million recovery; nine months ended September 30, 2025 – $97 million expense; nine months ended September 30, 2024 – $235 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, 2025 was $160 million (three months ended June 30, 2025 – $15 million gain, three months ended September 30, 2024 – $nil; nine months ended September 30, 2025 – $148 million loss; nine months ended September 30, 2024 – $13 million loss).

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

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

(5) During the second quarter of 2025, the Company acquired an interest in certain producing and non-producing crude oil and NGLs, and natural gas assets in the North America Exploration and Production segment, resulting in a pre- and after-tax gain on acquisition of $80 million representing the excess of the fair value of the net assets acquired compared to the total purchase consideration.

(6) During the 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 estimate of the 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 related expenditures for the purpose of the Company's non-GAAP measures.

(7) In connection with the Company's notice of withdrawal from Block 11B/12B in South Africa in the second quarter of 2024, the Company derecognized $62 million ($47 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense.

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 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Cash flows from operating activities	**$ 3,940**	$ 3,114	$ 3,002	**$ 11,338**	$ 9,954
Net change in non-cash working capital	**(432)**	(24)	680	**(538)**	180
Abandonment expenditures	**189**	193	204	**570**	495
Movements in other long-term assets (1)	**223**	(21)	35	**342**	44
Adjusted funds flow	**$ 3,920**	$ 3,262	$ 3,921	**$ 11,712**	$ 10,673

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

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

Adjusted net earnings from operations and adjusted funds flow, per common share (basic and diluted) are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 12 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.

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 15 to the financial statements.

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

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

Realized price ($/bbl and $/BOE) is a non-GAAP ratio calculated as realized crude oil and NGLs sales and total realized BOE sales (non-GAAP financial measures) divided by respective sales volumes. Realized crude oil and NGLs sales and total realized BOE sales is comprised of crude oil and NGLs sales and natural gas sales less blending and feedstock costs and other by-product sales, as disclosed in note 15 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 $/bbl)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Crude oil and NGLs (bbl/d)					
North America	**577,089**	551,248	479,889	**563,561**	494,674
International					
North Sea	**3,455**	6,778	9,020	**8,588**	11,713
Offshore Africa	**2,313**	500	20,450	**4,588**	12,129
Total International	**5,768**	7,278	29,470	**13,176**	23,842
Total sales volumes	**582,857**	558,526	509,359	**576,737**	518,516
Crude oil and NGLs sales (1)	**$ 4,773**	$ 4,655	$ 4,653	**$ 15,052**	$ 14,642
Less: Blending and feedstock costs (2)	**883**	1,119	946	**3,393**	3,466
Realized crude oil and NGLs sales	**$ 3,890**	$ 3,536	$ 3,707	**$ 11,659**	$ 11,176
Realized price ($/bbl)	**$ 72.57**	$ 69.58	$ 79.15	**$ 74.06**	$ 78.67

(1) Crude oil and NGLs sales in note 15 to the financial statements.

(2) Blending and feedstock costs in note 15 to the financial statements.

	Three Months Ended			Nine Months Ended	
($ millions, except BOE/d and $/BOE)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Barrels of oil equivalent (BOE/d)					
North America	**1,020,062**	950,888	819,606	**979,903**	843,074
International					
North Sea	**3,791**	7,262	9,246	**9,104**	11,961
Offshore Africa	**3,661**	1,585	22,021	**5,999**	13,809
Total International	**7,452**	8,847	31,267	**15,103**	25,770
Total sales volumes	**1,027,514**	959,735	850,873	**995,006**	868,844
Barrels of oil equivalent sales (1)	**$ 5,139**	$ 5,221	$ 4,889	**$ 16,674**	$ 15,681
Less: Blending and feedstock costs (2)	**883**	1,119	946	**3,393**	3,466
Less: Sulphur (income) expense	**(28)**	(18)	2	**(55)**	6
Realized barrels of oil equivalent sales	**$ 4,284**	$ 4,120	$ 3,941	**$ 13,336**	$ 12,209
Realized price ($/BOE)	**$ 45.31**	$ 47.17	$ 50.36	**$ 49.09**	$ 51.29

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 15 to the financial statements.

(2) Blending and feedstock costs in note 15 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 15 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 $/bbl and royalty rates)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Crude oil and NGLs sales (1)	**$ 4,724**	$ 4,595	$ 4,357	**$ 14,685**	$ 13,910
Less: Blending and feedstock costs (2)	**883**	1,119	946	**3,393**	3,466
Realized crude oil and NGLs sales	**$ 3,841**	$ 3,476	$ 3,411	**$ 11,292**	$ 10,444
Realized crude oil and NGLs prices ($/bbl)	**$ 72.35**	$ 69.30	$ 77.29	**$ 73.40**	$ 77.06
Crude oil and NGLs royalties (3)	**$ 702**	$ 467	$ 694	**$ 1,925**	$ 2,095
Crude oil and NGLs royalty rates	**18%**	13%	20%	**17%**	20%

(1) Crude oil and NGLs sales in note 15 to the financial statements.

(2) Blending and feedstock costs in note 15 to the financial statements.

(3) Item is a component of royalties in note 15 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 15 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 $/bbl)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
SCO sales volumes (bbl/d)	**579,209**	463,586	491,635	**548,197**	448,145
Crude oil and NGLs sales (1)	**$ 5,255**	$ 4,023	$ 5,208	**$ 15,157**	$ 13,901
Less: Blending and feedstock costs (2)	**573**	345	643	**1,621**	1,721
Realized SCO sales	**$ 4,682**	$ 3,678	$ 4,565	**$ 13,536**	$ 12,180
Realized SCO sales price ($/bbl)	**$ 87.85**	$ 87.22	$ 100.93	**$ 90.45**	$ 99.19

(1) Crude oil and NGLs sales in note 15 to the financial statements.

(2) Blending and feedstock costs in note 15 to the financial statements.

Change in Composition of Non-GAAP Financial Measure

During the fourth quarter of 2024, the Company revised the composition of its net capital expenditures non-GAAP financial measure to include acquisition capital related to a number of acquisitions for which agreements between parties have been reached. The inclusion of these acquisitions reflects the Company's estimate of its net capital expenditures at the time the 2025 budget was released. The composition of this measure has been updated to reflect the 2025 capital budget, but did not impact net capital expenditures in 2024.

Net Capital Expenditures

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2025**	Jun 30 2025	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Cash flows used in investing activities	**$ 2,234**	$ 1,941	$ 1,274	**$ 5,487**	$ 3,681
Net proceeds from investments	**—**	—	—	**—**	575
Net change in non-cash working capital	**(110)**	(26)	75	**(145)**	(173)
Net capital expenditures	**2,124**	1,915	1,349	**5,342**	4,083
Abandonment expenditures	**189**	193	204	**570**	495
Capital and abandonment expenditures	**$ 2,313**	$ 2,108	$ 1,553	**$ 5,912**	$ 4,578

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 2025**	Jun 30 2025	Dec 31 2024	Sep 30 2024
Undrawn bank credit facilities	**$ 4,201**	$ 4,723	$ 4,562	$ 5,450
Cash and cash equivalents	**113**	102	131	721
Liquidity	**$ 4,314**	$ 4,825	$ 4,693	$ 6,171

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 11 to the financial statements. A reconciliation of long-term debt, net is presented below.

($ millions)	**Sep 30 2025**	Jun 30 2025	Dec 31 2024	Sep 30 2024
Long-term debt	**$ 17,268**	$ 17,081	$ 18,819	$ 10,029
Less: cash and cash equivalents	**113**	102	131	721
Long-term debt, net	**$ 17,155**	$ 16,979	$ 18,688	$ 9,308

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 11 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 2025**	Jun 30 2025	Dec 31 2024	Sep 30 2024
Interest adjusted after-tax return:				
Net earnings, 12 months trailing	**$ 6,655**	$ 8,321	$ 6,106	$ 7,595
Interest and other financing expense, net of tax, 12 months trailing (1)	**561**	608	454	435
Interest adjusted after-tax return	**$ 7,216**	$ 8,929	$ 6,560	$ 8,030
12 months average current portion long-term debt (2)	**$ 1,529**	$ 1,528	$ 1,525	$ 1,366
12 months average long-term debt (2)	**14,596**	13,174	10,642	9,366
12 months average common shareholders' equity (2)	**40,314**	40,115	39,635	39,668
12 months average capital employed	**$ 56,439**	$ 54,817	$ 51,802	$ 50,400
After-tax return on average capital employed	**12.8%**	16.3%	12.7%	15.9%

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

(2) 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 2025**	Dec 31 2024
ASSETS			
Current assets			
Cash and cash equivalents		**$ 113**	$ 131
Accounts receivable		**3,745**	4,126
Inventory		**2,769**	2,793
Prepaids and other		**467**	279
Current portion of other long-term assets	5	**87**	76
		7,181	7,405
Exploration and evaluation assets	2	**2,729**	2,526
Property, plant and equipment	3	**73,368**	73,414
Lease assets	4	**1,363**	1,394
Other long-term assets	5	**948**	620
		$ 85,589	$ 85,359
LIABILITIES			
Current liabilities			
Accounts payable		**$ 1,326**	$ 1,079
Accrued liabilities		**4,154**	4,525
Current income taxes payable		**540**	92
Current portion of long-term debt	6	**829**	2,400
Current portion of other long-term liabilities	7	**1,464**	1,535
		8,313	9,631
Long-term debt	6	**16,439**	16,419
Other long-term liabilities	7	**10,379**	9,302
Deferred income taxes		**9,997**	10,539
		45,128	45,891
SHAREHOLDERS' EQUITY			
Share capital	9	**11,317**	11,064
Retained earnings		**28,909**	28,103
Accumulated other comprehensive income	10	**235**	301
		40,461	39,468
		$ 85,589	$ 85,359

Commitments and contingencies (note 14)

Approved by the Board of Directors on November 5, 2025.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Sep 30 2025**	Three Months Ended Sep 30 2024	Nine Months Ended **Sep 30 2025**	Nine Months Ended Sep 30 2024
Product sales	15	**$ 11,070**	$ 10,401	**$ 33,457**	$ 30,445
Less: royalties		**(1,554)**	(1,508)	**(4,304)**	(4,257)
Revenue		**9,516**	8,893	**29,153**	26,188
Expenses					
Production		**2,220**	1,949	**6,751**	6,085
Blending and feedstock		**1,970**	1,830	**6,215**	5,840
Transportation		**721**	515	**2,081**	1,444
Depletion, depreciation and amortization (1)	3,4	**3,211**	1,598	**6,846**	4,780
Administration		**152**	126	**455**	376
Share-based compensation	7	**63**	(46)	**97**	235
Asset retirement obligation accretion	7	**95**	97	**276**	291
Interest and other financing expense		**93**	154	**589**	450
Risk management loss (gain)	13	**214**	(21)	**86**	35
Foreign exchange loss (gain)		**290**	(118)	**(556)**	235
Gain on acquisition	3	**—**	—	**(80)**	—
Gain from investments		**—**	—	**—**	(56)
		9,029	6,084	**22,760**	19,715
Earnings before taxes		**487**	2,809	**6,393**	6,473
Current income tax expense	8	**419**	389	**1,368**	1,310
Deferred income tax (recovery) expense	8	**(532)**	154	**(492)**	195
Net earnings		**$ 600**	$ 2,266	**$ 5,517**	$ 4,968
Net earnings per common share					
Basic	12	**$ 0.29**	$ 1.07	**$ 2.64**	$ 2.33
Diluted	12	**$ 0.29**	$ 1.06	**$ 2.63**	$ 2.31

(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 (note 3).

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2025	Three Months Ended Sep 30 2024	Nine Months Ended Sep 30 2025	Nine Months Ended Sep 30 2024
Net earnings	**$ 600**	$ 2,266	**$ 5,517**	$ 4,968
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period, net of taxes of $1 million (2024 – $nil) – three months ended; $1 million (2024 – $nil) – nine months ended	**9**	1	**15**	1
Reclassification to net earnings, net of taxes of $1 million (2024 – $nil) – three months ended; $2 million (2024 – $nil) – nine months ended	**(9)**	(2)	**(16)**	(3)
	—	(1)	**(1)**	(2)
Foreign currency translation adjustment				
Translation of net investment	**30**	(21)	**(65)**	30
Other comprehensive income (loss), net of taxes	**30**	(22)	**(66)**	28
Comprehensive income	**$ 630**	$ 2,244	**$ 5,451**	$ 4,996

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended Sep 30 2025	Nine Months Ended Sep 30 2024
Share capital	9		
Balance – beginning of period		**$ 11,064**	$ 10,712
Issued upon exercise of stock options		**191**	248
Previously recognized liability on stock options exercised for common shares		**207**	315
Purchase of common shares under Normal Course Issuer Bid		**(145)**	(225)
Balance – end of period		**11,317**	11,050
Retained earnings			
Balance – beginning of period		**28,103**	28,948
Net earnings		**5,517**	4,968
Dividends on common shares	9	**(3,686)**	(3,354)
Purchase of common shares under Normal Course Issuer Bid, including tax	9	**(1,025)**	(1,915)
Balance – end of period		**28,909**	28,647
Accumulated other comprehensive income	10		
Balance – beginning of period		**301**	172
Other comprehensive (loss) income, net of taxes		**(66)**	28
Balance – end of period		**235**	200
Shareholders' equity		**$ 40,461**	$ 39,897

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Sep 30 2025	Three Months Ended Sep 30 2024	Nine Months Ended Sep 30 2025	Nine Months Ended Sep 30 2024
Operating activities					
Net earnings		**$ 600**	$ 2,266	**$ 5,517**	$ 4,968
Non-cash items					
Depletion, depreciation and amortization	3,4	**3,211**	1,598	**6,846**	4,780
Share-based compensation		**63**	(46)	**97**	235
Asset retirement obligation accretion		**95**	97	**276**	291
Unrealized risk management loss	13	**160**	—	**148**	13
Unrealized foreign exchange loss (gain)		**269**	(148)	**(677)**	106
Gain from investments		**—**	—	**—**	(50)
Gain on acquisition	3	**—**	—	**(80)**	—
Deferred income tax (recovery) expense		**(532)**	154	**(492)**	195
Realized foreign exchange on financing activities [(1)]		**54**	—	**77**	135
Abandonment expenditures	7	**(189)**	(204)	**(570)**	(495)
Other		**(223)**	(35)	**(342)**	(44)
Net change in non-cash working capital		**432**	(680)	**538**	(180)
Cash flows from operating activities		**3,940**	3,002	**11,338**	9,954
Financing activities					
Issuance of bank credit facilities and commercial paper, net	6	**712**	—	**692**	—
Repayment of other long-term debt	6	**(823)**	—	**(1,699)**	(1,008)
Payment of lease liabilities	4	**(87)**	(84)	**(253)**	(241)
Issue of common shares on exercise of stock options	9	**40**	21	**191**	248
Dividends on common shares		**(1,228)**	(1,118)	**(3,645)**	(3,319)
Purchase of common shares under Normal Course Issuer Bid	9	**(309)**	(741)	**(1,155)**	(2,109)
Cash flows used in financing activities		**(1,695)**	(1,922)	**(5,869)**	(6,429)
Investing activities					
Net expenditures on exploration and evaluation assets	2,15	**(63)**	(8)	**(120)**	(73)
Net expenditures on property, plant and equipment	3,15	**(2,061)**	(1,341)	**(5,222)**	(4,010)
Net proceeds from investments		**—**	—	**—**	575
Net change in non-cash working capital		**(110)**	75	**(145)**	(173)
Cash flows used in investing activities		**(2,234)**	(1,274)	**(5,487)**	(3,681)
Increase (decrease) in cash and cash equivalents		**11**	(194)	**(18)**	(156)
Cash and cash equivalents – beginning of period		**102**	915	**131**	877
Cash and cash equivalents – end of period		**$ 113**	$ 721	**$ 113**	$ 721
Interest paid on long-term debt		**$ 246**	$ 174	**$ 740**	$ 481
Income taxes paid, net		**$ 283**	$ 322	**$ 1,197**	$ 957

(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 direct and indirect interest in the Athabasca Oil Sands Project ("AOSP").

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

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

These interim consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34 "Interim Financial Reporting", following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2024. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2024.

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

During the second quarter of 2025, the Company entered into a long-term natural gas supply agreement that contains an embedded derivative (note 13). Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not closely related to the host contract, except when the host contract is an asset.

Critical Accounting Estimates and Judgements

The Company has made estimates, assumptions, and judgements regarding certain assets, liabilities, revenues and expenses in the preparation of these interim consolidated financial statements, primarily related to unsettled transactions and events as of the date of these interim consolidated financial statements, including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve. For the nine months ended September 30, 2025, these trade actions caused market uncertainty and impacted the global economy, including the oil and gas industry. The Company has taken into account the impacts of the trade actions and the unique circumstances they have created in making estimates, assumptions, and judgements in the preparation of the interim consolidated financial statements and continues to monitor the developments in the business environment and commodity market. Accordingly, actual results may differ from estimated amounts, and those differences may be material.

2. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2024	$ 2,408	$ —	$ 48	$ 70	$ 2,526
Additions / Acquisitions, net	**212**	**—**	**—**	**—**	**212**
Transfers to property, plant and equipment	**(7)**	**—**	**—**	**—**	**(7)**
Foreign exchange adjustments	**—**	**—**	**(2)**	**—**	**(2)**
At September 30, 2025	**$ 2,613**	**$ —**	**$ 46**	**$ 70**	**$ 2,729**

3. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2024	$ 88,964	$ 9,731	$ 5,023	$ 57,345	$ 495	$ 607	$ 162,165
Additions / Acquisitions, net	**3,806**	**16**	**309**	**1,400**	**6**	**59**	**5,596**
Transfers from exploration and evaluation assets	**7**	**—**	**—**	**—**	**—**	**—**	**7**
Change in asset retirement obligation estimates	**—**	**1,007**	**—**	**—**	**—**	**—**	**1,007**
Derecognitions (1)	**(415)**	**(4)**	**—**	**(646)**	**—**	**—**	**(1,065)**
Foreign exchange adjustments and other	**—**	**(333)**	**(179)**	**—**	**—**	**—**	**(512)**
At September 30, 2025	**$ 92,362**	**$ 10,417**	**$ 5,153**	**$ 58,099**	**$ 501**	**$ 666**	**$ 167,198**
Accumulated depletion and depreciation							
At December 31, 2024	$ 62,010	$ 9,392	$ 3,885	$ 12,765	$ 229	$ 470	$ 88,751
Expense	**3,287**	**85**	**75**	**1,863**	**13**	**21**	**5,344**
Derecognitions (1)	**(415)**	**(4)**	**—**	**(646)**	**—**	**—**	**(1,065)**
Recoverability charge	**—**	**1,258**	**—**	**—**	**—**	**—**	**1,258**
Foreign exchange adjustments and other	**1**	**(314)**	**(146)**	**1**	**—**	**—**	**(458)**
At September 30, 2025	**$ 64,883**	**$ 10,417**	**$ 3,814**	**$ 13,983**	**$ 242**	**$ 491**	**$ 93,830**
Net book value							
At September 30, 2025	**$ 27,479**	**$ —**	**$ 1,339**	**$ 44,116**	**$ 259**	**$ 175**	**$ 73,368**
At December 31, 2024	$ 26,954	$ 339	$ 1,138	$ 44,580	$ 266	$ 137	$ 73,414

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

During the nine months ended September 30, 2025, the Company acquired a number of producing and non-producing crude oil and NGLs, and natural gas assets in the North America Exploration and Production segment. These transactions were accounted for using the business combination method of accounting and are summarized below.

Grande Prairie NGLs and Natural Gas Acquisition

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

Palliser Block Crude Oil and NGLs, and Natural Gas Acquisition

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

Pro Forma Information

As a result of the Grande Prairie acquisition, revenue increased by approximately $80 million and net operating income (comprised of revenue less production and transportation expense) increased by approximately $40 million for the third quarter of 2025. Including the impact of depletion, depreciation and amortization, earnings before tax increased by approximately $10 million for the third quarter of 2025.

As a result of the Palliser Block acquisition, revenue increased by approximately $143 million and net operating income (comprised of revenue less production and transportation expenses) increased by approximately $72 million for the third quarter of 2025. Including the impact of depletion, depreciation and amortization, earnings before tax increased by approximately $27 million for the third quarter of 2025.

If the Grande Prairie and Palliser Block acquisitions had been completed on January 1, 2025, the Company estimates that pro forma revenue would have increased by approximately $739 million and pro forma net operating income (comprised of revenue less production and transportation expenses) would have increased by approximately $396 million for the nine months ended September 30, 2025. Including the impact of depletion, depreciation and amortization, the Company estimates earnings before taxes would have increased by approximately $188 million for the nine months ended September 30, 2025. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisitions actually occurred on January 1, 2025, or of future results. Pro forma results are based on historical information and reflect actual production in the period available for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition dates.

Other Acquisitions

For the three and nine months ended September 30, 2025, the Company also acquired a number of producing and non-producing crude oil and NGLs, and natural gas assets comprised of exploration and evaluation assets of $17 million, property, plant and equipment of $100 million, and assumed asset retirement and other obligations of $51 million for total cash consideration of $66 million.

Completion of Shell Swap Transaction

On November 1, 2025, subsequent to the third quarter of 2025, the Company completed the AOSP asset swap with Shell Canada Limited and affiliates (“Shell”). As a result of the transaction, the Company acquired the remaining 10% interest in the AOSP mines, associated reserves and additional working interests in a number of other non-producing oil sands leases in exchange for a 10% working interest in the Scotford Upgrader and Quest Carbon Capture and Storage (“Quest”) facilities. The Company now owns and operates 100% of the AOSP mines and retains a non-operated 80% working interest in the Scotford Upgrader and Quest. The transaction is effective March 1, 2025, and does not include any exchange of cash, except in respect to regular closing adjustments. As a result of the Company obtaining control of the AOSP mines, the swap is subject to accounting requirements for business combinations achieved in stages. The purchase price accounting will reflect the Company's revised interest in the assets and liabilities of the AOSP mines, the Scotford Upgrader and Quest. The Company is in the process of reviewing commercial agreements and obligations acquired in addition to the fair values of its existing and acquired interest.

North Sea Abandonment Activities

The Company is progressing its abandonment and decommissioning activities in the North Sea, including the tendering and awarding of contracts for the Ninian South Platform. Following a competitive bidding process in 2025, cost estimates have come in higher than originally budgeted. As a result, the Company has reviewed and updated estimates for abandonment and decommissioning costs for its North Sea assets, including the Ninian Central and South Platforms and T-Block (comprising the Tiffany, Toni, and Thelma fields).

In addition, based on current and forecasted economic conditions, including commodity pricing and market egress for T-Block volumes, the Company has determined that the T-Block assets are no longer economically viable. The Company is assessing alternatives for the potential acceleration of the T-Block decommissioning plan.

As a result, at September 30, 2025, the Company recognized a non-cash charge of $695 million, comprised of additional abandonment costs for the Ninian field of $734 million, net of deferred tax recoveries of $359 million, and an additional charge of $524 million for T-Block, net of deferred tax recoveries of $204 million, relating to current and forecasted economic conditions. The Company's estimate of its asset retirement obligations, including its long-term abandonment projects in the North Sea and associated tax recoveries, are subject to revision in future periods as abandonment activities progress.

4. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2024	$ 752	$ 468	$ 64	$ 110	$ 1,394
Additions	**15**	**219**	**14**	**42**	**290**
Depreciation	**(66)**	**(136)**	**(24)**	**(18)**	**(244)**
Derecognitions	**—**	**(29)**	**(29)**	**—**	**(58)**
Foreign exchange adjustments and other	**(4)**	**(7)**	**(5)**	**(3)**	**(19)**
At September 30, 2025	**$ 697**	**$ 515**	**$ 20**	**$ 131**	**$ 1,363**

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, 2025 were as follows:

	Sep 30 2025	Dec 31 2024
Lease liabilities	**$ 1,450**	$ 1,464
Less: current portion	**224**	255
	$ 1,226	$ 1,209

Total cash outflows for leases for the three months ended September 30, 2025, including payments related to short-term leases not reported as lease assets, were $376 million (three months ended September 30, 2024 – $332 million; nine months ended September 30, 2025 – $1,108 million; nine months ended September 30, 2024 – $987 million). Interest expense on leases for the three months ended September 30, 2025 was $16 million (three months ended September 30, 2024 – $18 million; nine months ended September 30, 2025 – $47 million; nine months ended September 30, 2024 – $53 million).

5. OTHER LONG-TERM ASSETS

	Sep 30 2025	Dec 31 2024
Long-term prepayments, contracts and other [1]	**$ 501**	$ 313
Prepaid cost of service tolls	**235**	166
Long-term inventory	**290**	204
Risk management (note 13)	**9**	13
	1,035	696
Less: current portion	**87**	76
	$ 948	$ 620

(1) Includes physical product sales contracts, interest on Petroleum Revenue Tax ("PRT") and corporate tax recoveries in the North Sea (note 3), and the unamortized cost of contributions to the Company's employee bonus program.

The Company has a 50% equity investment in NWRP. NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 barrels per day. The refinery processes approximately 50,000 barrels per day of bitumen feedstock, including 12,500 barrels per day of bitumen feedstock for the Company (25% toll payer) and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058 (note 14). Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 15).

The carrying value of the Company's interest in NWRP is $nil, and as at September 30, 2025, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $483 million (December 31, 2024 – $509 million). For the three months ended September 30, 2025, the Company's recovery of its share of unrecognized equity losses was $21 million (nine months ended September 30, 2025 – recovery of its share of unrecognized equity losses of $26 million; three months ended September 30, 2024 – recovery of unrecognized equity losses of $6 million; nine months ended September 30, 2024 – recovery of unrecognized equity losses of $45 million).

6. LONG-TERM DEBT

	Sep 30 2025	Dec 31 2024
Canadian dollar denominated debt, unsecured		
Medium-term notes	**$ 1,466**	$ 1,466
US dollar denominated debt, unsecured		
Bank credit facilities (September 30, 2025 – US$3,775 million; December 31, 2024 – US$3,393 million)	**5,249**	4,888
Commercial paper (September 30, 2025 – US$596 million; December 31, 2024 – US$467 million)	**829**	672
US dollar debt securities (September 30, 2025 – US$7,050 million; December 31, 2024 – US$8,250 million)	**9,804**	11,883
	17,348	18,909
Less: original issue discounts, net [1]	**11**	12
transaction costs [1] [2]	**69**	78
	17,268	18,819
Less: current portion of commercial paper	**829**	672
current portion of long-term debt [1] [2]	**—**	1,728
	$ 16,439	$ 16,419

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

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

Bank Credit Facilities and Commercial Paper

As at September 30, 2025, the Company had undrawn revolving bank credit facilities of $4,201 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. As at September 30, 2025, the Company had $829 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

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

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

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

The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at September 30, 2025 was 4.9% (September 30, 2024 – $nil outstanding), and on total long-term debt outstanding for the nine months ended September 30, 2025 was 5.0% (September 30, 2024 – 4.9%).

As at September 30, 2025, letters of credit and guarantees aggregating to $802 million were outstanding (December 31, 2024 – $1,542 million).

Medium-Term Notes

In July 2023, 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 expired in August 2025. 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.

US Dollar Debt Securities

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

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

In July 2023, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expired in August 2025. 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.

In October 2025, subsequent to the third quarter of 2025, the Company filed a prospectus supplement to the base shelf prospectus. Under the prospectus supplement, up to US$1,500 million of the registered debt securities may be issued in exchange for up to US$1,500 million of the Company's outstanding restricted 5.00% US dollar debt securities due December 2029 and 5.40% US dollar debt securities due December 2034. Any notes issued under such exchange will not be subject to transfer restrictions and will not result in a change in the current level of indebtedness.

7. OTHER LONG-TERM LIABILITIES

	Sep 30 2025	Dec 31 2024
Asset retirement obligations	**$ 9,705**	$ 8,607
Lease liabilities (note 4)	**1,450**	1,464
Share-based compensation	**418**	620
Transportation and processing contracts	**42**	58
Risk management (note 13)	**148**	8
Other	**80**	80
	11,843	10,837
Less: current portion	**1,464**	1,535
	$ 10,379	$ 9,302

Asset Retirement Obligations

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

	Sep 30 2025	Dec 31 2024
Balance – beginning of period	**$ 8,607**	$ 7,690
Liabilities incurred	**26**	28
Liabilities acquired, net	**420**	171
Liabilities settled	**(570)**	(646)
Asset retirement obligation accretion	**276**	389
Revision of cost, inflation, and timing estimates (1)	**1,007**	417
Change in discount rates	**—**	419
Foreign exchange adjustments	**(61)**	139
Balance – end of period	**9,705**	8,607
Less: current portion	**901**	787
	$ 8,804	$ 7,820

(1) Includes normal course revisions of cost, inflation, and timing estimates, as well as revisions to abandonment and decommissioning costs for the Ninian field and T-Block assets in the North Sea.

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 2025	Dec 31 2024
Balance – beginning of period	**$ 620**	$ 780
Share-based compensation expense	**97**	279
Cash payment for stock options surrendered and PSUs vested	**(93)**	(84)
Transferred to common shares	**(207)**	(358)
Other	**1**	3
Balance – end of period	**418**	620
Less: current portion	**320**	463
	$ 98	$ 157

8. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Nine Months Ended	
Expense (recovery)	**Sep 30 2025**	Sep 30 2024	**Sep 30 2025**	Sep 30 2024
Current corporate income tax – North America [1]	**$ 499**	$ 433	**$ 1,597**	$ 1,393
Current corporate income tax – North Sea	**(37)**	(12)	**(108)**	(30)
Current corporate income tax – Offshore Africa	**—**	12	**5**	22
Current PRT [2] – North Sea	**(45)**	(47)	**(133)**	(67)
Other taxes	**2**	3	**7**	(8)
Current income tax	**419**	389	**1,368**	1,310
Deferred corporate income tax	**(143)**	120	**(130)**	148
Deferred PRT [2] – North Sea	**(389)**	34	**(362)**	47
Deferred income tax	**(532)**	154	**(492)**	195
Income tax	**$ (113)**	$ 543	**$ 876**	$ 1,505

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

(2) Petroleum Revenue Tax.

For the three and nine months ended September 30, 2025, the Company recognized deferred tax recoveries comprised of a deferred corporate income tax recovery of $143 million (September 30, 2024 – $nil) and a deferred PRT recovery of $420 million (September 30, 2024 – $nil) in connection with the increase in the Company's estimate of abandonment costs for the planned decommissioning activities at the Ninian field and T-Block in the North Sea (note 3).

9. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued Common Shares	Nine Months Ended Sep 30, 2025 Number of shares (thousands)		Amount
Balance – beginning of period	**2,102,996**	**$**	**11,064**
Issued upon exercise of stock options	**9,066**		**191**
Previously recognized liability on stock options exercised for common shares	**—**		**207**
Purchase of common shares under Normal Course Issuer Bid	**(26,980)**		**(145)**
Balance – end of period	**2,085,082**	**$**	**11,317**

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 5, 2025, the Board of Directors approved a 4% increase in the quarterly dividend to $0.5875 per common share, beginning with the dividend paid on April 4, 2025.

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

Normal Course Issuer Bid

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

For the nine months ended September 30, 2025, the Company purchased 26,980,000 common shares at a weighted average price of $42.81 per common share for a total cost, including tax, of $1,170 million. Retained earnings were reduced by $1,025 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2025, up to and including November 4, 2025, the Company purchased 2,500,000 common shares at a weighted average price of $44.03 per common share for a total cost, including tax, of $112 million.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding as at September 30, 2025:

	Nine Months Ended Sep 30, 2025 Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of period	**50,806**	**$**	**33.90**
Granted	**18,804**		**43.40**
Exercised for common shares	**(9,066)**		**21.12**
Surrendered for cash settlement	**(455)**		**21.86**
Forfeited	**(2,763)**		**38.37**
Outstanding – end of period	**57,326**	**$**	**38.91**
Exercisable – end of period	**10,887**	**$**	**33.41**

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.

10. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Sep 30 2025	Sep 30 2024
Derivative financial instruments designated as cash flow hedges	$ 69	$ 70
Foreign currency translation adjustment	166	130
	$ 235	$ 200

11. 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 growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the ratio of current and long-term debt less cash and cash equivalents divided by the sum of the carrying value of shareholders' equity plus current and long-term debt less cash and cash equivalents. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. As at September 30, 2025, the ratio was within the target range at 29.8%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS 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 2025	Dec 31 2024
Long-term debt	$ 17,268	$ 18,819
Less: cash and cash equivalents	113	131
Long-term debt, net	$ 17,155	$ 18,688
Total shareholders' equity	$ 40,461	$ 39,468
Debt to book capitalization	29.8%	32.1%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at September 30, 2025, the Company was in compliance with this covenant.

12. NET EARNINGS PER COMMON SHARE

		Three Months Ended		Nine Months Ended	
		Sep 30 2025	Sep 30 2024	Sep 30 2025	Sep 30 2024
Weighted average common shares outstanding – basic (thousands of shares)		2,087,944	2,119,970	2,093,827	2,131,767
Effect of dilutive stock options (thousands of shares)		6,046	13,093	7,001	15,417
Weighted average common shares outstanding – diluted (thousands of shares)		2,093,990	2,133,063	2,100,828	2,147,184
Net earnings		$ 600	$ 2,266	$ 5,517	$ 4,968
Net earnings per common share	– basic	$ 0.29	$ 1.07	$ 2.64	$ 2.33
	– diluted	$ 0.29	$ 1.06	$ 2.63	$ 2.31

13. 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 2025	Dec 31 2024
Balance – beginning of period	$ 5	$ 9
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities (1) (2) (3) (4) (5)	(146)	(6)
Foreign exchange	1	1
Other comprehensive income	1	1
Balance – end of period	(139)	5
Less: current portion	5	5
	$ (144)	$ —

(1) Risk management assets and liabilities are disclosed in note 5 and note 7, respectively.

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

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

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

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

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2025	Sep 30 2024	Sep 30 2025	Sep 30 2024
Net realized risk management loss (gain)	$ 54	$ (21)	$ (62)	$ 22
Net unrealized risk management loss	160	—	148	13
	$ 214	$ (21)	$ 86	$ 35

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, 2025	
	Carrying amount	Level 1 Fair Value
Fixed rate long-term debt (1) (2)	$ 11,190	$ 11,467

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

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

Embedded Derivative Contract

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

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

The Company recognizes a (gain) loss on risk management activities in the statements of earnings related to its natural gas embedded derivative. The (gain) loss is determined by the relative movements in fair value compared to the prior period balance sheet date. For the nine months ended September 30, 2025, the Company recognized an unrealized loss of $145 million and a corresponding risk management liability.

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

($ millions)	Sep 30, 2025
JKM price	
Increase / decrease of US$0.10/MMBtu	**38 / (38)**
Discount rate	
Increase / decrease of 1%	**(55) / 64**

Financial Risk Factors

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

a) Market risk

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

Commodity price risk management

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

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

Foreign currency exchange rate risk management

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

As at September 30, 2025, the Company had US$2,624 million of foreign currency forward contracts outstanding (December 31, 2024 – US$2,187 million), with original terms of up to 90 days, of which US$1,500 million were designated as derivatives held for trading (December 31, 2024 – US$1,521 million) and US$1,124 million were designated as cash flow hedges (December 31, 2024 – US$666 million).

As at September 30, 2025, the Company had no foreign currency put option contracts outstanding. The Company periodically sells put option contracts which grant the purchaser the right, but not the obligation to exercise the contract on the expiry date (European option) and are designated as derivatives held for trading. The amount that may be payable upon exercise is initially recognized as a liability valued at the amount paid by the counterparty. The option is remeasured to fair value at each reporting date with gains and losses recognized in risk management activities in net earnings. If the option expires unexercised, the remaining liability is derecognized.

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and, where appropriate, ensuring that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at September 30, 2025, substantially all of the Company's accounts receivable were due within normal trade terms.

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

c) Liquidity risk

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

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

As at September 30, 2025, the maturity dates of the Company's financial liabilities were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 1,326	$ —	$ —	$ —
Accrued liabilities	$ 4,154	$ —	$ —	$ —
Long-term debt (1)	$ 829	$ 3,047	$ 6,345	$ 7,127
Other long-term liabilities (2)	$ 227	$ 175	$ 417	$ 779
Interest and other financing expense (3)	$ 966	$ 938	$ 1,634	$ 3,114

(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, $224 million; one to less than two years, $175 million; two to less than five years, $417 million; and thereafter, $634 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at September 30, 2025.

14. 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, 2025:

	Remaining 2025	2026	2027	2028	2029	Thereafter
Product transportation, purchases, and processing (1)	$ 602	$ 2,380	$ 2,253	$ 2,107	$ 2,004	$ 19,595
North West Redwater Partnership service toll (2)	$ 35	$ 117	$ 97	$ 98	$ 97	$ 4,018
Offshore vessels and equipment	$ 94	$ —	$ —	$ —	$ —	$ —
Field equipment and power	$ 29	$ 32	$ 29	$ 28	$ 27	$ 216
Other	$ 31	$ 119	$ 19	$ 19	$ 18	$ 195

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

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $1,882 million of interest payable over the 40-year tolling period, ending in 2058 (note 5).

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.

15. 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	
	2025	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Segmented product sales																
Crude oil and NGLs	**$ 4,724**	$ 4,357	**$ 14,685**	$ 13,910	**$ 28**	$ 93	**$ 236**	$ 365	**$ 21**	$ 203	**$ 131**	$ 367	**$ 4,773**	$ 4,653	**$ 15,052**	$ 14,642
Natural gas	**355**	224	**1,581**	1,001	**2**	1	**11**	4	**9**	11	**30**	34	**366**	236	**1,622**	1,039
Other income and revenue [1]	**41**	(3)	**74**	(10)	**—**	—	**—**	4	**—**	2	**1**	3	**41**	(1)	**75**	(3)
Total segmented product sales	**5,120**	4,578	**16,340**	14,901	**30**	94	**247**	373	**30**	216	**162**	404	**5,180**	4,888	**16,749**	15,678
Less: royalties	**(710)**	(696)	**(1,978)**	(2,120)	**(1)**	—	**(1)**	(1)	**(1)**	(11)	**(7)**	(20)	**(712)**	(707)	**(1,986)**	(2,141)
Segmented revenue	**4,410**	3,882	**14,362**	12,781	**29**	94	**246**	372	**29**	205	**155**	384	**4,468**	4,181	**14,763**	13,537
Segmented expenses																
Production	**914**	777	**2,637**	2,490	**63**	101	**351**	319	**15**	46	**58**	86	**992**	924	**3,046**	2,895
Blending and feedstock	**883**	946	**3,393**	3,466	**—**	—	**—**	—	**—**	—	**—**	—	**883**	946	**3,393**	3,466
Transportation	**507**	363	**1,501**	1,109	**2**	3	**6**	9	**—**	—	**—**	—	**509**	366	**1,507**	1,118
Depletion, depreciation and amortization [3]	**1,188**	924	**3,365**	2,821	**1,285**	17	**1,358**	58	**20**	96	**92**	251	**2,493**	1,037	**4,815**	3,130
Asset retirement obligation accretion	**57**	58	**163**	173	**13**	16	**41**	48	**3**	2	**7**	6	**73**	76	**211**	227
Risk management loss (commodity derivatives)	**162**	1	**151**	7	**—**	—	**—**	—	**—**	—	**—**	—	**162**	1	**151**	7
Gain on acquisition	**—**	—	**(80)**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(80)**	—
Total segmented expenses	**3,711**	3,069	**11,130**	10,066	**1,363**	137	**1,756**	434	**38**	144	**157**	343	**5,112**	3,350	**13,043**	10,843
Segmented earnings (loss)	**$ 699**	$ 813	**$ 3,232**	$ 2,715	**$ (1,334)**	$ (43)	**$ (1,510)**	$ (62)	**$ (9)**	$ 61	**$ (2)**	$ 41	**$ (644)**	$ 831	**$ 1,720**	$ 2,694
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management loss (gain) (other)																
Foreign exchange loss (gain)																
Gain from investments																
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	
	2025	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Segmented product sales																
Crude oil and NGLs [2]	**$ 5,255**	$ 5,208	**$ 15,157**	$ 13,901	**$ 24**	$ 20	**$ 68**	$ 61	**$ 416**	$ 62	**$ 797**	$ 99	**$ 10,468**	$ 9,943	**$ 31,074**	$ 28,703
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**33**	21	**93**	78	**399**	257	**1,715**	1,117
Other income and revenue [1]	**54**	—	**127**	(3)	**106**	191	**464**	620	**2**	11	**2**	11	**203**	201	**668**	625
Total segmented product sales	**5,309**	5,208	**15,284**	13,898	**130**	211	**532**	681	**451**	94	**892**	188	**11,070**	10,401	**33,457**	30,445
Less: royalties	**(842)**	(801)	**(2,318)**	(2,116)	**—**	—	**—**	—	**—**	—	**—**	—	**(1,554)**	(1,508)	**(4,304)**	(4,257)
Segmented revenue	**4,467**	4,407	**12,966**	11,782	**130**	211	**532**	681	**451**	94	**892**	188	**9,516**	8,893	**29,153**	26,188
Segmented expenses																
Production	**1,135**	935	**3,440**	2,902	**77**	78	**216**	245	**16**	12	**49**	43	**2,220**	1,949	**6,751**	6,085
Blending and feedstock	**573**	643	**1,621**	1,721	**82**	166	**359**	509	**432**	75	**842**	144	**1,970**	1,830	**6,215**	5,840
Transportation	**206**	151	**537**	323	**3**	3	**38**	12	**3**	(5)	**(1)**	(9)	**721**	515	**2,081**	1,444
Depletion, depreciation and amortization [3]	**713**	556	**2,018**	1,637	**5**	5	**13**	13	**—**	—	**—**	—	**3,211**	1,598	**6,846**	4,780
Asset retirement obligation accretion	**22**	21	**65**	64	**—**	—	**—**	—	**—**	—	**—**	—	**95**	97	**276**	291
Risk management loss (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**162**	1	**151**	7
Gain on acquisition	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(80)**	—
Total segmented expenses	**2,649**	2,306	**7,681**	6,647	**167**	252	**626**	779	**451**	82	**890**	178	**8,379**	5,990	**22,240**	18,447
Segmented earnings (loss)	**$ 1,818**	$ 2,101	**$ 5,285**	$ 5,135	**$ (37)**	$ (41)	**$ (94)**	$ (98)	**$ —**	$ 12	**$ 2**	$ 10	**$ 1,137**	$ 2,903	**$ 6,913**	$ 7,741
Non-segmented expenses																
Administration													**152**	126	**455**	376
Share-based compensation													**63**	(46)	**97**	235
Interest and other financing expense													**93**	154	**589**	450
Risk management loss (gain) (other)													**52**	(22)	**(65)**	28
Foreign exchange loss (gain)													**290**	(118)	**(556)**	235
Gain from investments													**—**	—	**—**	(56)
Total non-segmented expenses													**650**	94	**520**	1,268
Earnings before taxes													**487**	2,809	**6,393**	6,473
Current income tax													**419**	389	**1,368**	1,310
Deferred income tax													**(532)**	154	**(492)**	195
Net earnings													**$ 600**	$ 2,266	**$ 5,517**	$ 4,968

(1) Includes the sale of diesel and other refined products in the Midstream and Refining segment, and other income.

(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 (note 3).

Capital Expenditures [1]

	Nine Months Ended					
	Sep 30, 2025			Sep 30, 2024		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ 120**	**$ 85**	**$ 205**	$ 76	$ (37)	$ 39
Offshore Africa	**—**	**—**	**—**	(3)	(62)	(65)
	120	**85**	**205**	73	(99)	(26)
Property, plant and equipment						
Exploration and Production						
North America	**3,432**	**(34)**	**3,398**	2,325	(396)	1,929
North Sea	**16**	**1,003**	**1,019**	36	—	36
Offshore Africa	**309**	**—**	**309**	122	—	122
	3,757	**969**	**4,726**	2,483	(396)	2,087
Oil Sands Mining and Upgrading	**1,400**	**(646)**	**754**	1,489	(381)	1,108
Midstream and Refining	**6**	**—**	**6**	10	—	10
Head Office	**59**	**—**	**59**	28	—	28
	5,222	**323**	**5,545**	4,010	(777)	3,233
	$ 5,342	**$ 408**	**$ 5,750**	$ 4,083	$ (876)	$ 3,207

(1) This table provides a reconciliation of capitalized costs, reported in note 2 and note 3, 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 2025	Dec 31 2024
Exploration and Production		
North America	**$ 33,345**	$ 32,670
North Sea	**758**	702
Offshore Africa	**1,512**	1,412
Other	**59**	31
Oil Sands Mining and Upgrading	**48,399**	49,221
Midstream and Refining	**1,229**	1,099
Head Office	**287**	224
	$ 85,589	$ 85,359

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

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

Interest coverage ratios for the twelve month period ended September 30, 2025:	
Interest coverage (times)	
Net earnings (1)	11.9x
Adjusted funds flow (2)	24.9x

(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.

This Page Left Intentionally Blank

CORPORATE INFORMATION

Board of Directors

Catherine M. Best, FCA, ICD.D
Shelley A.M. Brown, CM, FCPA, FCA, ICD.D, O.C.[1]
M. Elizabeth Cannon, Ph.D, O.C.
N. Murray Edwards, O.C.
Christopher L. Fong
Ambassador Gordon D. Giffin
Wilfred A. Gobert
Christine M. Healy
Steve W. Laut
Honourable Frank J. McKenna, P.C., O.C., O.N.B., K.C.
Scott G. Stauth
David A. Tuer
Annette M. Verschuren, O.C.

(1) Ms. Brown was appointed to the Board of Directors and Audit Committee on November 4, 2025.

Officers

N. Murray Edwards
Executive Chairman

Scott G. Stauth
President

Jay E. Froc
Chief Operating Officer, Oil Sands

Robin S. Zabek
Chief Operating Officer, Exploration and Production

Ron K. Laing
Chief Commercial and Corporate Development Officer

Victor C. Darel
Chief Financial Officer

Troy J.P. Andersen
Senior Vice-President, Canadian Conventional Field Operations

Calvin J. Bast
Senior Vice-President, Production

Dwayne F. Giggs
Senior Vice-President, Exploration

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

Sheryl L. Kapeluck
Senior Vice-President, Finance

Devin C. Lowe
Senior Vice-President, Exploitation

Warren P. Raczynski
Senior Vice-President, Thermal

Kara L. Slemko
Senior Vice-President, Commercial Operations and Corporate Development

Trevor T. Wagil
Senior Vice-President, Oil Sands Mining and Upgrading

Brenda G. Balog
Vice-President, Legal and General Counsel

Erin L. Lunn
Vice-President, Land

Mark A. Overwater
Vice-President, Marketing

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

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

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

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

Stock Listing

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

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario
Computershare Investor Services LLC
New York, New York

Investor Relations

Phone: (403) 514-7777
Email: ir@cnrl.com

CANADIAN NATURAL RESOURCES LIMITED

T (403) 517-6700 F (403) 517-7350 E ir@cnrl.com

2100, 855 - 2 Street S.W. Calgary, Alberta, T2P4J8

www.cnrl.com