



SECOND QUARTER REPORT

THREE AND SIX MONTHS ENDED JUNE 30, 2025

TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED 2025 SECOND QUARTER RESULTS

Canadian Natural's President, Scott Stauth, commented on the Company's second quarter results, "Our relentless focus on continuous improvement combined with effective and efficient operations drove strong performance year to date in 2025. Our ability to effectively allocate capital across our strong asset base provides us with a competitive advantage. This ability, combined with accretive acquisitions, creates significant long-term value for our shareholders. Our culture of accountability and the strength of our assets is a unique advantage that results in both capital and operating cost savings and maximizes value for our shareholders.

We successfully completed a planned turnaround at our Athabasca Oil Sands Project ("AOSP") in Q2/25, five days ahead of schedule and on budget. Production and upgrader utilization at Horizon and AOSP, before and after the turnaround, was high, driven by strong performance on our Reliability Enhancement and debottlenecking projects. In July 2025, Oil Sands Mining and Upgrading Synthetic Crude Oil ("SCO") production averaged approximately 602,000 bbl/d with upgrader utilization of 106%, and we expect the second half of 2025 to continue to deliver strong operating results.

In Q2/25, despite the turnaround at AOSP which reduced production levels in the quarter by approximately 120,000 bbl/d, we achieved quarterly production volumes totaling approximately 1,420 MBOE/d, including liquids production of 1,019 Mbb/d and natural gas production of 2,407 MMcf/d. Total corporate production on a BOE basis in Q2/25 was up approximately 135,000 BOE/d from Q2/24 levels, reflecting opportunistic acquisitions and organic growth across our asset base achieved in the last 12 months.

We continue to achieve strong results from our drilling programs across our Conventional assets as we are realizing capital efficiencies, resulting in high levels of activity without increased capital. This includes our multilateral heavy crude oil program where we are targeting to drill 26 more wells in 2025 than originally budgeted. Importantly, the low operating costs on these multilateral wells drive strong returns on capital, adding significant value.

On our recently acquired Duvernay assets, we continue to see reductions on both capital and operating costs supporting execution of organic growth opportunities. We are realizing more value than we planned at the time of the acquisition. This is being achieved through our commitment to continuous improvement and a strong team culture that focuses on improving our operating costs. In Q2/25, we had strong operating costs in the Duvernay of \$8.43/BOE, a decrease of 11% from Q1/25 levels of \$9.52/BOE.

On June 26, 2025, we closed an acquisition of lands and production in the Palliser Block located in southern Alberta. We had budgeted to close the Palliser Block acquisition on March 1, 2025, which would have added production volumes of approximately 50,000 BOE/d, including 20,000 bbl/d of Mannville light crude oil and NGLs, in Q2/25. This acquisition and production was included in our original 2025 capital budget and production guidance, but due to this delayed closing in late June 2025, added only 2,000 BOE/d to our production levels for Q2/25. This acquisition also included approximately 1.1 million net acres of high quality land, with currently identified significant light crude oil inventory on the lands of approximately 850 locations.

Subsequent to quarter end, on July 2, 2025, we closed an acquisition of liquids-rich Montney assets located in the Grande Prairie area of northern Alberta for approximately \$750 million with production from the acquisition of approximately 32,000 BOE/d, including 12,500 bbl/d of NGLs. Our original 2025 capital budget and production guidance did not include this acquisition. These assets are directly adjacent to our existing core Montney assets, providing opportunities for synergies while adding approximately 120,000 net acres of high quality land with currently identified significant liquids-rich inventory of approximately 150 locations."

Canadian Natural's Chief Financial Officer, Victor Darel, added "In Q2/25, we generated adjusted net earnings of \$1.5 billion or \$0.71 per share, and adjusted funds flow of \$3.3 billion or \$1.56 per share. We returned approximately \$1.6 billion to our shareholders in the quarter, including \$1.2 billion in dividends and \$0.4 billion in share repurchases.

Our business model is robust and sustainable, resulting in a top tier WTI breakeven in the low to mid-US\$40 per barrel range at which prices we generate the adjusted funds flow required to cover both maintenance capital levels and

dividends. Our balance sheet remains strong with liquidity of approximately \$4.8 billion as at June 30, 2025, providing significant flexibility.

Our leading financial results combined with our safe, reliable, effective and efficient operations provide us with unique competitive advantages, all of which drive material free cash flow generation and strong returns on capital, maximizing value for our shareholders."

HIGHLIGHTS

(\$ millions, except per common share amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Net earnings	\$ 2,459	\$ 2,458	\$ 1,715	\$ 4,917	\$ 2,702
Per common share – basic	\$ 1.17	\$ 1.17	\$ 0.80	\$ 2.34	\$ 1.26
– diluted	\$ 1.17	\$ 1.17	\$ 0.80	\$ 2.34	\$ 1.25
Adjusted net earnings from operations ⁽¹⁾	\$ 1,496	\$ 2,436	\$ 1,892	\$ 3,932	\$ 3,366
Per common share – basic ⁽²⁾	\$ 0.71	\$ 1.16	\$ 0.89	\$ 1.88	\$ 1.57
– diluted ⁽²⁾	\$ 0.71	\$ 1.16	\$ 0.88	\$ 1.87	\$ 1.56
Cash flows from operating activities	\$ 3,114	\$ 4,284	\$ 4,084	\$ 7,398	\$ 6,952
Adjusted funds flow ⁽¹⁾	\$ 3,262	\$ 4,530	\$ 3,614	\$ 7,792	\$ 6,752
Per common share – basic ⁽²⁾	\$ 1.56	\$ 2.16	\$ 1.69	\$ 3.72	\$ 3.16
– diluted ⁽²⁾	\$ 1.55	\$ 2.15	\$ 1.68	\$ 3.70	\$ 3.13
Cash flows used in investing activities	\$ 1,941	\$ 1,312	\$ 1,015	\$ 3,253	\$ 2,407
Net capital expenditures ⁽³⁾	\$ 1,915	\$ 1,303	\$ 1,621	\$ 3,218	\$ 2,734
Net capital expenditures ⁽³⁾ , excluding net acquisition costs	\$ 1,691	\$ 1,303	\$ 1,621	\$ 2,994	\$ 2,734
Abandonment expenditures	\$ 193	\$ 188	\$ 129	\$ 381	\$ 291
Daily production, before royalties					
Natural gas (MMcf/d)	2,407	2,451	2,110	2,429	2,129
Crude oil and NGLs (bbl/d)	1,019,149	1,173,804	934,066	1,096,049	954,866
Equivalent production (BOE/d) ⁽⁴⁾	1,420,358	1,582,348	1,285,798	1,500,905	1,309,649

(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 six months ended June 30, 2025 dated August 6, 2025.

(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and six months ended June 30, 2025 dated August 6, 2025.

(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 for the three and six months ended June 30, 2025 dated August 6, 2025.

(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.

- The strength of Canadian Natural's long life low decline asset base, supported by safe, reliable, effective and efficient operations, makes our business unique, robust and sustainable. In Q2/25, the Company generated strong financial results, including:
 - Net earnings of approximately \$2.5 billion and adjusted net earnings from operations of approximately \$1.5 billion.
 - Cash flows from operating activities of approximately \$3.1 billion.
 - Adjusted funds flow of approximately \$3.3 billion.
- Canadian Natural continues to maintain a strong balance sheet and financial flexibility, with approximately \$4.8 billion in liquidity ⁽¹⁾ as at June 30, 2025.
 - Subsequent to quarter end, the Company repaid US\$600 million of US dollar debt securities due in July 2025.
 - Subsequent to quarter end, Canadian Natural received a new long-term investment grade credit rating of BBB+ from Fitch Ratings. Canadian Natural's existing long-term credit ratings are A (low) from DBRS, Baa1 from Moody's and BBB- from S&P.

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this press release and the Company's MD&A for the three and six months ended June 30, 2025 dated August 6, 2025.

- Canadian Natural continues to focus on safe, reliable, effective and efficient operations, delivering strong quarterly average production of 1,420,358 BOE/d in Q2/25, consisting of total liquids production of 1,019,149 bbl/d and natural gas production of 2,407 MMcf/d. Total BOE production in Q2/25 is approximately 10% higher than Q2/24 levels, reflecting both opportunistic acquisitions and organic growth completed over the last 12 months.
- Oil Sands Mining and Upgrading production averaged 463,808 bbl/d of SCO in Q2/25, an increase of 13% from Q2/24 levels. The increase is a result of the Reliability Enhancement Project, eliminating the need for a turnaround at Horizon in 2025, and the Scotford Upgrader debottleneck which were completed in 2024, combined with the additional 20% working interest in AOSP acquired in December 2024, partially offset by the Q2/25 turnaround at AOSP completed successfully and five days ahead of schedule in the quarter.
 - Subsequent to quarter end, July 2025 Oil Sands Mining and Upgrading production averaged approximately 602,000 bbl/d with upgrader utilization of 106%, and the Company expects the second half of 2025 to continue to deliver strong operating results.
- Canadian Natural's highly successful multilateral drilling program continues to unlock opportunity on the Company's extensive, high quality land throughout our primary heavy crude oil assets of approximately 3.0 million net acres.
 - As a result of capital efficiencies achieved across the Company and our deep inventory of high return opportunities, Canadian Natural is now targeting to drill 182 net primary heavy crude oil multilateral wells in 2025, 26 more wells than in the original budget and an increase of approximately 60 wells or 50% from 2024 drilling levels.
 - Increasing well counts and optimized well designs continue to deliver strong results with average peak rates of approximately 230 bbl/d per well achieved from these multilateral wells in the first six months of 2025.
- On the liquids-rich Duvernay assets, Canadian Natural continues to achieve strong performance as the Company applies to these assets its continuous improvement culture, effective and efficient operations and area expertise.
 - Our extended well lengths, which on average are 20% longer than 2024 lengths and optimized completions designs, combined with strong execution continues to lower development costs. On a length normalized basis, combined drilling and completion costs for 2025 are now targeting an improvement of approximately 16% or \$2.0 million per well lower compared to 2024 costs, a further improvement of \$0.2 million per well compared to Q1/25 levels.
 - As a result of operating synergies and our focus on continuous improvement, the Company achieved strong operating costs in our first six months of operating the Duvernay assets, averaging \$8.43/BOE in Q2/25, a decrease of 11% compared to Q1/25 levels of \$9.52/BOE.
- On June 26, 2025, Canadian Natural closed an acquisition of lands and production in the Palliser Block located in southern Alberta. The Company had budgeted to close the Palliser Block acquisition on March 1, 2025, which would have added production volumes of approximately 50,000 BOE/d, including 20,000 bbl/d of Mannville light crude oil and NGLs, in Q2/25. This acquisition and production was included in the Company's original 2025 capital budget and production guidance, but due to this delayed closing in late June 2025, added only 2,000 BOE/d to production levels in Q2/25. This acquisition also included approximately 1.1 million net acres of high quality land, with currently identified significant light crude oil inventory on the lands of approximately 850 locations.
- Subsequent to quarter end, on July 2, 2025, Canadian Natural closed an acquisition of liquids-rich Montney assets located in the Grande Prairie area of northern Alberta for approximately \$750 million with production from the acquisition of approximately 32,000 BOE/d, including 12,500 bbl/d of NGLs. The Company's original 2025 capital budget and production guidance did not include this acquisition. These assets are directly adjacent to the Company's existing core Montney assets, providing opportunities for synergies while adding approximately 120,000 net acres of high quality land with currently identified significant liquids-rich inventory of approximately 150 locations.
- Canadian Natural plans to update our annual 2025 corporate production guidance and capital forecast upon closing of the AOSP swap, which is targeted for Q3/25.

RETURNS TO SHAREHOLDERS

- Concurrent with the closing of the Chevron acquisition in December 2024 the Company revised its free cash flow policy to be 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, up from the previous target of \$10 billion, free cash flow allocation will be 100% to shareholder returns.
- Due to accretive acquisitions completed in late 2024 and 2025 year to date and strong operational results, Canadian Natural targets to provide similar shareholder returns in 2025 as compared to 2024. This is targeted to be achieved despite only allocating 60% of free cash flow in 2025 to shareholder returns as compared to allocating 100% of free cash flow in 2024 to shareholder returns. These shareholder returns in 2025 will be as a result of the previously announced dividend increase in Q1/25 and continuation of Canadian Natural's share buyback program throughout the year. In addition, Canadian Natural targets to reduce its year end 2025 net debt levels by approximately \$2 billion from year end 2024 levels.
- 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 Q2/25 were strong, totaling approximately \$1.6 billion, comprised of \$1.2 billion of dividends and \$0.4 billion through the repurchase and cancellation of approximately 8.6 million common shares at a weighted average price of \$41.46 per share.
 - Year to date in 2025, up to and including August 6, 2025, the Company has returned a total of approximately \$4.6 billion directly to shareholders through \$3.6 billion in dividends and \$1.0 billion through the repurchase and cancellation of approximately 22.4 million common shares at a weighted average price of \$42.76 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 October 3, 2025 to shareholders of record at the close of business on September 19, 2025.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

Canadian Natural has a balanced and diverse portfolio of assets, primarily Canadian-based, with international exposure in the UK portion of the North Sea and Offshore Africa. Canadian Natural's production is well balanced between light crude oil, medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil) and SCO (herein collectively referred to as "crude oil") and natural gas and NGLs. This balance provides optionality for capital investments, maximizing value for the Company's shareholders.

Underpinning this asset base is the Company's long life low decline production, representing approximately 77% of total budgeted liquids production in 2025, the majority of which is zero decline high value SCO production from the Company's world class Oil Sands Mining and Upgrading assets. The remaining balance of the Company's long life low decline production comes from its top tier thermal in situ oil sands operations and Pelican Lake heavy crude oil assets. The combination of these long life low decline assets, low reserves replacement costs, and effective and efficient operations results in substantial and sustainable adjusted funds flow throughout the commodity price cycle.

In addition, Canadian Natural maintains a substantial inventory of low capital exposure projects within the Company's conventional asset base. These projects can be executed quickly and, in the right economic conditions, provide excellent returns and maximize value for our shareholders. Supporting these projects is the Company's undeveloped landbase which enables large, repeatable drilling programs that can be optimized over time. Additionally, Canadian Natural maximizes long-term value by maintaining high ownership and operatorship of its assets, allowing the Company to control the nature, timing and extent of development. Low capital exposure projects can be stopped or started relatively quickly depending upon success, market conditions or corporate needs.

Canadian Natural's balanced portfolio, built with both long life low decline assets and low capital exposure assets, enables effective capital allocation, production growth and value creation.

Drilling Activity

	Six Months Ended			
	June 30, 2025		June 30, 2024	
(number of wells)	Gross	Net	Gross	Net
Crude oil ⁽¹⁾	160	155	125	124
Natural gas	50	41	49	40
Dry	1	1	1	1
Subtotal	211	197	175	165
Stratigraphic test / service wells	513	490	457	391
Total	724	687	632	556
Success rate (excluding stratigraphic test / service wells)		99%		99%

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 197 net crude oil and natural gas producer wells in the first six months of 2025, 32 more than in the first six months of 2024.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Crude oil and NGLs production (bbl/d)	271,022	276,532	231,592	273,761	234,537
Net wells targeting crude oil	57	57	33	114	71
Net successful wells drilled	57	56	33	113	71
Success rate	100%	98%	100%	99%	100%

- North America E&P liquids production, excluding thermal in situ, averaged 271,022 bbl/d in Q2/25, an increase of 17% or approximately 40,000 bbl/d from Q2/24 levels, reflecting production volumes from the Duvernay assets acquired in December 2024, along with strong organic growth from our heavy crude oil multilateral wells as well as liquids-rich natural gas and light crude oil assets.
- Primary heavy crude oil production averaged 87,288 bbl/d in Q2/25, an increase of 10% from Q2/24 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 the Company's extensive, high quality land throughout our primary heavy crude oil assets of approximately 3.0 million net acres.
 - As a result of capital efficiencies achieved across the Company and our deep inventory of high return opportunities, Canadian Natural is now targeting to drill 182 net primary heavy crude oil multilateral wells in 2025, 26 more wells than in the original budget and an increase of approximately 60 wells or 50% from 2024 drilling levels.
 - Increasing well counts and optimized well designs continue to deliver strong results with average peak rates of approximately 230 bbl/d per well achieved in the first six months of 2025.
 - Operating costs in the Company's primary heavy crude oil operations averaged \$17.44/bbl (US\$12.60/bbl) in Q2/25, comparable to Q2/24 levels.
- Pelican Lake production averaged 43,078 bbl/d in Q2/25 a decrease of 4% from Q2/24 levels, reflecting low natural field declines from this long life low decline asset.
 - Operating costs at Pelican Lake averaged \$9.01/bbl (US\$6.51/bbl) in Q2/25, comparable to Q2/24 levels.
- North America light crude oil and NGLs production averaged 140,656 bbl/d in Q2/25, an increase of 31% or approximately 33,000 bbl/d compared to Q2/24 levels, primarily driven by the Duvernay assets acquired in December 2024 and strong drilling results across our liquids-rich natural gas assets.
 - Operating costs in the Company's North America light crude oil and NGLs operations averaged \$10.94/bbl (US\$7.90/bbl) in Q2/25, a decrease of 20% from Q2/24 levels of \$13.75/bbl, primarily reflecting higher production volumes.
 - On the liquids-rich Duvernay assets, Canadian Natural continues to achieve strong performance as the Company applies to these assets its continuous improvement culture, effective and efficient operations and area expertise.
 - Our extended well lengths, which on average are 20% longer than 2024 lengths and optimized completions designs, combined with strong execution continues to lower development costs. On a length normalized basis, combined drilling and completion costs for 2025 are now targeting an improvement of approximately 16% or \$2.0 million per well lower compared to 2024 costs, a further improvement of \$0.2 million per well compared to Q1/25 levels.
 - As a result of operating synergies and our focus on continuous improvement, the Company achieved strong operating costs in our first six months of operating the Duvernay assets, averaging \$8.43/BOE in Q2/25, a decrease of 11% compared to Q1/25 levels of \$9.52/BOE.
 - The Company is targeting to drill 43 gross wells in the Duvernay as part of the 2025 capital development program and remains on track to achieve budget production of approximately 60,000 BOE/d, with an average initial rate of approximately 1,600 BOE/d per well year to date.

North America Natural Gas

	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Natural gas production (MMcf/d)	2,398	2,436	2,099	2,417	2,117
Net wells targeting natural gas	22	19	25	41	41
Net successful wells drilled	22	19	24	41	40
Success rate	100%	100%	96%	100%	98%

- North America natural gas production averaged 2,398 MMcf/d in Q2/25, an increase of 14% from Q2/24 levels, driven by strong drilling results in the Company's liquids-rich Montney, Duvernay and Deep Basin natural gas assets.
 - North America natural gas operating costs averaged \$1.07/Mcf in Q2/25, a decrease of 10% from Q2/24 levels of \$1.19/Mcf, primarily reflecting higher production volumes and cost efficiencies.

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Bitumen production (bbl/d)	274,789	284,706	268,044	279,721	268,100
Net wells targeting bitumen	24	18	30	42	53
Net successful wells drilled	24	18	30	42	53
Success rate	100%	100%	100%	100%	100%

- Thermal in situ production averaged 274,789 bbl/d in Q2/25, an increase of 3% from Q2/24 levels, reflecting strong results from the recent pad additions at Primrose, partially offset by natural field declines and impacts from wildfires.
 - Thermal in situ operating costs remain strong, averaging \$11.05/bbl (US\$7.98/bbl) in Q2/25, comparable to Q2/24 levels.
- 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 is targeting to begin drilling a Cyclic Steam Stimulation ("CSS") pad in late Q3/25 with production targeted to come on in 2026.
 - At Jackfish, the Company brought the recently drilled Steam Assisted Gravity Drainage ("SAGD") pad on production in July 2025.
 - At Kirby, the Company is targeting to bring the recently drilled five well pair SAGD pad on production in Q4/25.
 - At Pike, the Company has completed drilling two SAGD pads, which will be tied into existing Jackfish facilities and targets to keep the Jackfish plants at full capacity. The first of these two pads is targeted to come on production in Q1/26 and the second 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 Company's commercial scale solvent SAGD pad at Kirby North, we began solvent injection in June 2024. In Q2/25, we executed workovers on two well pairs to enhance SORs, solvent recovery and production trends, which we will continue to monitor over the coming months.
 - 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.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Synthetic crude oil production (bbl/d) ⁽¹⁾⁽²⁾	463,808	595,116	410,518	529,099	427,863

(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 463,808 bbl/d of SCO in Q2/25, an increase of 13% from Q2/24 levels. The increase is a result of the Reliability Enhancement Project, eliminating the need for a turnaround at Horizon in 2025, and the Scotford Upgrader debottleneck which were completed in 2024, combined with the additional 20% working interest in AOSP acquired in December 2024, partially offset by the Q2/25 turnaround at AOSP completed successfully and five days ahead of schedule in the quarter.
 - Subsequent to quarter end, July 2025 Oil Sands Mining and Upgrading production averaged approximately 602,000 bbl/d with upgrader utilization of 106%, and the Company expects the second half of 2025 to continue to deliver strong operating results.
 - Oil Sands Mining and Upgrading operating costs averaged \$26.53/bbl (US\$19.17/bbl) of SCO in Q2/25, an increase of 2% from Q2/24 levels, reflecting the AOSP turnaround in Q2/25.
- Oil Sands Mining and Upgrading continues to outperform our expectations following both the Reliability Enhancement Project at Horizon and the debottlenecking at AOSP that were completed in 2024, driving high utilization and industry leading operating costs.
 - At Horizon, the Reliability Enhancement Project increased the capacity of zero decline, high value SCO production to 264,000 bbl/d over a two year timeframe by shifting the planned turnarounds to once every two years from the previous annual cycle. As a result, 2025 is the first year without a planned turnaround, resulting in high targeted utilization. With enhanced infrastructure now in place, the Company can perform certain maintenance activities with zero production impact.
- 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.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Crude oil production (bbl/d)	9,530	17,450	23,912	13,468	24,367
Natural gas production (MMcf/d)	9	15	11	12	12

- International E&P crude oil production volumes averaged 9,530 bbl/d in Q2/25, a decrease of 60% compared to Q2/24 levels. The decrease reflects temporary suspension of production at Baobab in Offshore Africa due to the planned life extension project on its floating production storage and offloading ("FPSO") vessel, as well as maintenance and decommissioning activities in the North Sea and natural field declines.
 - The annual production impact in 2025 from the life extension project on the Baobab FPSO is targeted to be approximately 7,800 bbl/d, with production targeted to resume in Q2/26.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Benchmark Commodity Prices					
WTI benchmark price (US\$/bbl) ⁽¹⁾	\$ 63.71	\$ 71.42	\$ 80.55	\$ 67.55	\$ 78.76
WCS heavy differential (discount) to WTI (US\$/bbl) ⁽¹⁾	\$ (10.19)	\$ (12.66)	\$ (13.54)	\$ (11.42)	\$ (16.44)
WCS heavy differential as a percentage of WTI (%) ⁽¹⁾	16%	18%	17%	17%	21%
Condensate benchmark price (US\$/bbl)	\$ 63.42	\$ 69.89	\$ 77.11	\$ 66.64	\$ 74.95
SCO price (US\$/bbl) ⁽¹⁾	\$ 64.69	\$ 69.07	\$ 83.33	\$ 66.87	\$ 76.38
SCO premium (discount) to WTI (US\$/bbl) ⁽¹⁾	\$ 0.98	\$ (2.35)	\$ (2.78)	\$ (0.68)	\$ (2.38)
AECO benchmark price (C\$/GJ)	\$ 1.97	\$ 1.92	\$ 1.36	\$ 1.94	\$ 1.65
Realized Prices					
Exploration & Production liquids realized price (C\$/bbl) ⁽²⁾⁽³⁾⁽⁴⁾⁽⁵⁾	\$ 69.58	\$ 79.85	\$ 86.64	\$ 74.82	\$ 78.43
SCO realized price (C\$/bbl) ⁽¹⁾⁽³⁾⁽⁴⁾⁽⁵⁾	\$ 87.22	\$ 95.52	\$ 108.81	\$ 91.88	\$ 98.18
Natural gas realized price (C\$/Mcf) ⁽⁴⁾	\$ 2.58	\$ 3.13	\$ 1.59	\$ 2.86	\$ 2.07

(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 for the three and six months ended June 30, 2025 dated August 6, 2025.

- Canadian Natural has a balanced and diverse product mix of natural gas, NGLs, heavy crude oil, light crude oil, bitumen and SCO, complemented with a balanced and diverse marketing strategy.
- WTI prices averaged US\$63.71/bbl in Q2/25, decreases of US\$7.71/bbl and US\$16.84/bbl from Q1/25 and Q2/24 levels respectively. The decreases reflect weaker global demand outlooks amid ongoing trade and tariff uncertainty, combined with larger than expected OPEC+ output hikes in Q2/25.
- SCO pricing averaged US\$64.69/bbl in Q2/25, representing a US\$0.98/bbl premium to WTI pricing, compared to a US\$2.35/bbl discount to WTI in Q1/25 and a US\$2.78 discount to WTI in Q2/24. The SCO differential strengthened in Q2/25 relative to the comparable periods, primarily driven by lower production levels in the Western Canadian Sedimentary Basin ("WCSB") as a result of maintenance activities that took place in Q2/25.
- The WCS differential to WTI continued to narrow in Q2/25, averaging US\$10.19/bbl, representing a US\$2.47/bbl improvement from Q1/25 and a US\$3.35/bbl improvement from Q2/24. The tighter WCS differential reflects the start-up of the Trans Mountain Expansion ("TMX") pipeline in Q2/24, which has brought structural change to the Canadian oil market by increasing egress, reducing price volatility and diversifying market access. The narrowing of the WCS differential in Q2/25 also reflects stronger United States Gulf Coast ("USGC") heavy crude oil pricing and production impacts in the WCSB as a result of maintenance activities and shut-in production from wildfires that occurred in Q2/25.
- The North West Redwater refinery primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 60,549 bbl/d in Q2/25, reflecting a turnaround that commenced in Q2/25.
- 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 USGC, being approximately 23% of 2025 budgeted 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 Company has total committed capacity on the TMX pipeline of 169,000 bbl/d providing access to markets on Canada's west coast.
 - Canadian Natural has total committed capacity of 77,500 bbl/d on the Flanagan South pipeline and an additional 10,000 bbl/d of committed capacity on the Keystone Base pipeline, diversifying the Company's heavy crude oil access to the USGC.

- AECO natural gas prices averaged \$1.97/GJ in Q2/25, an increase of \$0.61/GJ from Q2/24 and a \$0.05/GJ increase from Q1/25. The increase in AECO natural gas pricing compared to Q2/24 primarily reflects stronger NYMEX benchmark pricing combined with increased exports out of the WCSB.
 - In 2025, the Company is targeting to use the equivalent of approximately 33% of budgeted natural gas production in its Oil Sands Mining and Upgrading and thermal operations, with approximately 35% targeted to be sold at AECO/Station 2 pricing, and approximately 32% targeted to be exported to other North American and international markets capturing higher natural gas prices, maximizing value from its diversified natural gas marketing portfolio.
- 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. 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 as well as in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and six months ended June 30, 2025 dated August 6, 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 June 30, 2025 and comparable periods is shown below:

(\$ millions)	Three Months Ended			
	Jun 30 2025	Mar 31 2025	Jun 30 2024	
Adjusted funds flow ⁽¹⁾	\$ 3,262	\$ 4,530	\$ 3,614	
Less: Dividends on common shares	1,233	1,184	1,125	
Net capital expenditures ⁽²⁾	1,915	1,303	1,621	
Abandonment expenditures	193	188	129	
Free cash flow	\$ (79)	\$ 1,855	\$ 739	

(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 six months ended June 30, 2025 dated August 6, 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 six months ended June 30, 2025 dated August 6, 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)				
	Jun 30 2025	Mar 31 2025	Dec 31 2024	Jun 30 2024
Long-term debt	\$ 17,081	\$ 17,428	\$ 18,819	\$ 10,149
Less: cash and cash equivalents	102	93	131	915
Long-term debt, net	\$ 16,979	\$ 17,335	\$ 18,688	\$ 9,234

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 budget reflects budgeted 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 budgeted future expenditures. Abandonment expenditures are reported before the impact of current income tax recoveries. Current tax recoveries are refundable at a rate of approximately 23% in Canada and a combined current income tax and Petroleum Revenue Tax ("PRT") rate approximating 70% to 75% in the UK portion of the North Sea. The Company is eligible to recover interest on refunded PRT previously paid.

Capital Efficiency

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

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MANAGEMENT'S DISCUSSION AND ANALYSIS

ADVISORY

Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "focus", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration", or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to the Company's strategy or strategic focus, capital budget, expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, 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 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 uncertainty in the international trade environment, including with respect to tariffs, export restrictions, embargoes, and key trade agreements (including tariffs imposed or announced by the US government on certain goods and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded to additional goods); 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; 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 tariffs imposed or announced by the US government on certain goods and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded to additional goods), 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 six months ended June 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 six months ended June 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 six months ended June 30, 2025 in relation to the comparable periods in 2024 and the first 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 August 6, 2025.

FINANCIAL HIGHLIGHTS

(\$ millions, except per common share amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Product sales ⁽¹⁾	\$ 9,675	\$ 12,712	\$ 10,622	\$ 22,387	\$ 20,044
Crude oil and NGLs	\$ 8,874	\$ 11,732	\$ 10,084	\$ 20,606	\$ 18,760
Natural gas	\$ 600	\$ 716	\$ 331	\$ 1,316	\$ 860
Net earnings	\$ 2,459	\$ 2,458	\$ 1,715	\$ 4,917	\$ 2,702
Per common share – basic	\$ 1.17	\$ 1.17	\$ 0.80	\$ 2.34	\$ 1.26
– diluted	\$ 1.17	\$ 1.17	\$ 0.80	\$ 2.34	\$ 1.25
Adjusted net earnings from operations ⁽²⁾	\$ 1,496	\$ 2,436	\$ 1,892	\$ 3,932	\$ 3,366
Per common share – basic ⁽³⁾	\$ 0.71	\$ 1.16	\$ 0.89	\$ 1.88	\$ 1.57
– diluted ⁽³⁾	\$ 0.71	\$ 1.16	\$ 0.88	\$ 1.87	\$ 1.56
Cash flows from operating activities	\$ 3,114	\$ 4,284	\$ 4,084	\$ 7,398	\$ 6,952
Adjusted funds flow ⁽²⁾	\$ 3,262	\$ 4,530	\$ 3,614	\$ 7,792	\$ 6,752
Per common share – basic ⁽³⁾	\$ 1.56	\$ 2.16	\$ 1.69	\$ 3.72	\$ 3.16
– diluted ⁽³⁾	\$ 1.55	\$ 2.15	\$ 1.68	\$ 3.70	\$ 3.13
Cash flows used in investing activities	\$ 1,941	\$ 1,312	\$ 1,015	\$ 3,253	\$ 2,407
Net capital expenditures ⁽⁴⁾	\$ 1,915	\$ 1,303	\$ 1,621	\$ 3,218	\$ 2,734
Abandonment expenditures	\$ 193	\$ 188	\$ 129	\$ 381	\$ 291

(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 six months ended June 30, 2025 were \$4,917 million compared with \$2,702 million for the six months ended June 30, 2024. Net earnings for the six months ended June 30, 2025 included non-operating income, net of tax, of \$985 million compared with non-operating losses of \$664 million for the six months ended June 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, 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 six months ended June 30, 2025 were \$3,932 million compared with \$3,366 million for the six months ended June 30, 2024.

Net earnings for the second quarter of 2025 were \$2,459 million compared with \$1,715 million for the second quarter of 2024 and \$2,458 million for the first quarter of 2025. Net earnings for the second quarter of 2025 included non-operating income, net of tax, of \$963 million compared with non-operating losses of \$177 million for the second quarter of 2024 and non-operating income of \$22 million for the first 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 loss from investments, the gain on acquisition, 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 second quarter of 2025 were \$1,496 million compared with \$1,892 million for the second quarter of 2024 and \$2,436 million for the first quarter of 2025.

The movements in net earnings and adjusted net earnings from operations for the three and six months ended June 30, 2025 from the three and six months ended June 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 crude oil and NGLs realized pricing⁽¹⁾ in the North America Exploration and Production segment.

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

- lower realized SCO pricing and sales volumes in the Oil Sands Mining and Upgrading segment, and
- lower realized crude oil and NGLs pricing and 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 (gain) loss, gain on acquisition, and the loss (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.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the six months ended June 30, 2025 were \$7,398 million compared with \$6,952 million for the six months ended June 30, 2024. Cash flows from operating activities for the second quarter of 2025 were \$3,114 million compared with \$4,084 million for the second quarter of 2024 and \$4,284 million for the first 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 six months ended June 30, 2025 was \$7,792 million compared with \$6,752 million for the six months ended June 30, 2024. Adjusted funds flow for the second quarter of 2025 was \$3,262 million compared with \$3,614 million for the second quarter of 2024 and \$4,530 million for the first 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, accrued interest on Petroleum Revenue Tax ("PRT") recoveries, and prepaid cost of service tolls.

Production Volumes

Crude oil and NGLs production before royalties for the second quarter of 2025 of 1,019,149 bbl/d increased 9% from 934,066 bbl/d for the second quarter of 2024 and decreased 13% from 1,173,804 bbl/d for the first quarter of 2025. Natural gas production before royalties for the second quarter of 2025 of 2,407 MMcf/d increased 14% from 2,110 MMcf/d for the second quarter of 2024 and was comparable with 2,451 MMcf/d for the first quarter of 2025. Total production before royalties for the second quarter of 2025 of 1,420,358 BOE/d increased 10% from 1,285,798 BOE/d for the second quarter of 2024 and decreased 10% from 1,582,348 BOE/d for the first 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 \$69.58 per bbl for the second quarter of 2025, a decrease of 20% from \$86.64 per bbl for the second quarter of 2024 and a decrease of 13% from \$79.85 per bbl for the first quarter of 2025. The realized natural gas price increased 62% to average \$2.58 per Mcf for the second quarter of 2025 from \$1.59 per Mcf for the second quarter of 2024 and decreased 18% from \$3.13 per Mcf for the first quarter of 2025. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price decreased 20% to average \$87.22 per bbl for the second quarter of 2025 from \$108.81 per bbl for the second quarter of 2024 and decreased 9% from \$95.52 per bbl for the first 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 "Oil Sands Mining and Upgrading" sections of this MD&A.

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

Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense⁽¹⁾ averaged \$14.03 per bbl for the second quarter of 2025, a decrease of 4% from \$14.54 per bbl for the second quarter of 2024 and a decrease of 11% from \$15.74 per bbl for the first quarter of 2025. Natural gas production expense⁽¹⁾ averaged \$1.11 per Mcf for the second quarter of 2025, a decrease of 8% from \$1.21 per Mcf for the second quarter of 2024 and a decrease of 8% from \$1.20 per Mcf for the first quarter of 2025. In the Oil Sands Mining and Upgrading segment, production expense⁽¹⁾ averaged \$26.53 per bbl for the second quarter of 2025, comparable with \$25.95 per bbl for the second quarter of 2024 and an increase of 21% from \$21.88 per bbl for the first 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 "Oil Sands Mining and Upgrading" sections of this MD&A.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

(\$ millions, except per common share amounts)	Jun 30 2025	Mar 31 2025	Dec 31 2024	Sep 30 2024
Product sales ⁽¹⁾	\$ 9,675	\$ 12,712	\$ 11,064	\$ 10,401
Crude oil and NGLs	\$ 8,874	\$ 11,732	\$ 10,381	\$ 9,943
Natural gas	\$ 600	\$ 716	\$ 451	\$ 257
Net earnings	\$ 2,459	\$ 2,458	\$ 1,138	\$ 2,266
Net earnings per common share				
– basic	\$ 1.17	\$ 1.17	\$ 0.54	\$ 1.07
– diluted	\$ 1.17	\$ 1.17	\$ 0.54	\$ 1.06
(\$ millions, except per common share amounts)	Jun 30 2024	Mar 31 2024	Dec 31 2023	Sep 30 2023
Product sales ⁽¹⁾	\$ 10,622	\$ 9,422	\$ 10,679	\$ 11,762
Crude oil and NGLs	\$ 10,084	\$ 8,676	\$ 9,829	\$ 10,944
Natural gas	\$ 331	\$ 529	\$ 603	\$ 599
Net earnings	\$ 1,715	\$ 987	\$ 2,627	\$ 2,344
Net earnings per common share ⁽²⁾				
– basic	\$ 0.80	\$ 0.46	\$ 1.22	\$ 1.08
– diluted	\$ 0.80	\$ 0.46	\$ 1.21	\$ 1.06

(1) Further details related to product sales for the three months ended June 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.

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

- **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, 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, 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, increased 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 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 accrued interest on PRT recoveries.
- **Foreign exchange** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt and working capital.

BUSINESS ENVIRONMENT

Global crude oil benchmark pricing declined through the second quarter of 2025, driven by demand outlook concerns due to ongoing tariff and trade uncertainty and the impact of larger than expected OPEC+ output hikes. Crude oil benchmark price volatility provided pricing support in the latter half of the quarter as escalating tensions in the Middle East led to concerns of supply disruptions. Natural gas benchmark pricing remained stable in the second quarter of 2025. In Canada, the start-up of LNG Canada, which began exporting cargoes at the outset of the third quarter of 2025, will provide additional market egress and is expected to support AECO benchmark pricing.

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 June 30, 2025, the Company had undrawn revolving bank credit facilities of \$4,723 million. Including cash and cash equivalents, the Company had approximately \$4,825 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			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
WTI benchmark price (US\$/bbl)	\$ 63.71	\$ 71.42	\$ 80.55	\$ 67.55	\$ 78.76
Dated Brent benchmark price (US\$/bbl)	\$ 67.78	\$ 75.68	\$ 84.90	\$ 71.71	\$ 84.07
WCS Heavy Differential from WTI (US\$/bbl)	\$ 10.19	\$ 12.66	\$ 13.54	\$ 11.42	\$ 16.44
SCO price (US\$/bbl)	\$ 64.69	\$ 69.07	\$ 83.33	\$ 66.87	\$ 76.38
Condensate benchmark price (US\$/bbl)	\$ 63.42	\$ 69.89	\$ 77.11	\$ 66.64	\$ 74.95
NYMEX benchmark price (US\$/MMBtu)	\$ 3.44	\$ 3.66	\$ 1.89	\$ 3.55	\$ 2.06
AECO benchmark price (C\$/GJ)	\$ 1.97	\$ 1.92	\$ 1.36	\$ 1.94	\$ 1.65
US/Canadian dollar average exchange rate (US\$)	\$ 0.7225	\$ 0.6969	\$ 0.7308	\$ 0.7096	\$ 0.7360

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\$67.55 per bbl for the six months ended June 30, 2025, a decrease of 14% from US\$78.76 per bbl for the six months ended June 30, 2024. WTI averaged US\$63.71 per bbl for the second quarter of 2025, a decrease of 21% from US\$80.55 per bbl for the second quarter of 2024 and a decrease of 11% from US\$71.42 per bbl for the first 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\$71.71 per bbl for the six months ended June 30, 2025, a decrease of 15% from US\$84.07 per bbl for the six months ended June 30, 2024. Brent averaged US\$67.78 per bbl for the second quarter of 2025, a decrease of 20% from US\$84.90 per bbl for the second quarter of 2024 and a decrease of 10% from US\$75.68 per bbl for the first quarter of 2025.

The decrease in WTI and Brent benchmark pricing for the three and six months ended June 30, 2025 from the comparable periods reflected weaker global demand outlooks amid ongoing tariff and trade uncertainty, combined with larger than expected OPEC+ output hikes in the second quarter of 2025.

The WCS Heavy Differential averaged US\$11.42 per bbl for the six months ended June 30, 2025, compared with US\$16.44 per bbl for the six months ended June 30, 2024. The WCS Heavy Differential averaged US\$10.19 per bbl for the second quarter of 2025, compared with US\$13.54 per bbl for the second quarter of 2024 and US\$12.66 per bbl for the first quarter of 2025. The narrowing of the WCS Heavy Differential for the six months ended June 30, 2025 from the six months ended June 30, 2024 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 second quarter of 2025 from the comparable periods primarily reflected production impacts in the Western Canadian Sedimentary Basin ("WCSB") as a result of maintenance activities and shut-in production from wildfires that occurred in the second quarter of 2025.

The SCO price averaged US\$66.87 per bbl for the six months ended June 30, 2025, a decrease of 12% from US\$76.38 per bbl for the six months ended June 30, 2024. The SCO price averaged US\$64.69 per bbl for the second quarter of 2025, a decrease of 22% from US\$83.33 per bbl for the second quarter of 2024 and a decrease of 6% from US\$69.07 per bbl for the first quarter of 2025. The decrease in SCO pricing for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected weaker WTI benchmark pricing. The decrease in SCO pricing for the second quarter of 2025 from the first quarter of 2025 primarily reflected weaker WTI benchmark pricing, partially offset by the SCO differential strengthening due to lower production levels in the WCSB as a result of maintenance activities that took place in the second quarter of 2025.

NYMEX benchmark pricing averaged US\$3.55 per MMBtu for the six months ended June 30, 2025, an increase of 72% from US\$2.06 per MMBtu for the six months ended June 30, 2024. NYMEX benchmark pricing averaged US\$3.44 per MMBtu for the second quarter of 2025, an increase of 82% from US\$1.89 per MMBtu for the second quarter of 2024 and a decrease of 6% from US\$3.66 per MMBtu for the first quarter of 2025. The increase in NYMEX natural gas prices for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected lower US inventory levels following cold weather conditions in the first quarter of 2025, combined with higher LNG exports out of the US Gulf Coast in 2025. The decrease in NYMEX natural gas pricing for the second quarter of 2025 from the first quarter of 2025 primarily reflected reduced LNG exports from the US Gulf Coast due to maintenance activities, as well as seasonal demand factors.

AECO benchmark pricing averaged \$1.94 per GJ for the six months ended June 30, 2025, an increase of 18% from \$1.65 per GJ for the six months ended June 30, 2024. AECO benchmark pricing averaged \$1.97 per GJ for the second quarter of 2025, an increase of 45% from \$1.36 per GJ for the second quarter of 2024 and comparable with \$1.92 per GJ for the first quarter of 2025. The increase in AECO natural gas prices for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected stronger NYMEX benchmark pricing, combined with increased exports out of the WCSB.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	545,811	561,238	499,636	553,482	502,636
North America – Oil Sands Mining and Upgrading ⁽¹⁾	463,808	595,116	410,518	529,099	427,863
International – Exploration and Production					
North Sea	7,761	11,507	11,295	9,623	11,864
Offshore Africa	1,769	5,943	12,617	3,845	12,503
Total International ⁽²⁾	9,530	17,450	23,912	13,468	24,367
Total Crude oil and NGLs	1,019,149	1,173,804	934,066	1,096,049	954,866
Natural gas (MMcf/d) ⁽³⁾					
North America	2,398	2,436	2,099	2,417	2,117
International					
North Sea	3	4	2	4	2
Offshore Africa	6	11	9	8	10
Total International	9	15	11	12	12
Total Natural gas	2,407	2,451	2,110	2,429	2,129
Total Barrels of oil equivalent (BOE/d)	1,420,358	1,582,348	1,285,798	1,500,905	1,309,649
Product mix					
Light and medium crude oil and NGLs	11%	10%	10%	10%	10%
Pelican Lake heavy crude oil	3%	3%	4%	3%	3%
Primary heavy crude oil	6%	5%	6%	6%	6%
Bitumen (thermal oil)	19%	18%	21%	19%	21%
Synthetic crude oil ⁽¹⁾	33%	38%	32%	35%	33%
Natural gas	28%	26%	27%	27%	27%
Percentage of product sales ^{(1) (4) (5)}					
Crude oil and NGLs	93%	94%	97%	93%	95%
Natural gas	7%	6%	3%	7%	5%

(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			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	472,329	455,307	394,025	463,865	403,888
North America – Oil Sands Mining and Upgrading ⁽¹⁾	397,052	480,227	332,272	438,410	351,554
International – Exploration and Production					
North Sea	7,746	11,493	11,270	9,609	11,838
Offshore Africa	1,692	5,685	12,057	3,678	11,906
Total International	9,438	17,178	23,327	13,287	23,744
Total Crude oil and NGLs	878,819	952,712	749,624	915,562	779,186
Natural gas (MMcf/d)					
North America	2,325	2,348	2,077	2,336	2,063
International					
North Sea	3	4	2	4	2
Offshore Africa	6	11	9	8	10
Total International	9	15	11	12	12
Total Natural gas	2,334	2,363	2,088	2,348	2,075
Total Barrels of oil equivalent (BOE/d)	1,267,787	1,346,536	1,097,693	1,306,945	1,124,974

(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 six months ended June 30, 2025 averaged 1,096,049 bbl/d, an increase of 15% from 954,866 bbl/d for the six months ended June 30, 2024. Crude oil and NGLs production before royalties for the second quarter of 2025 averaged 1,019,149 bbl/d, an increase of 9% from 934,066 bbl/d for the second quarter of 2024 and a decrease of 13% from 1,173,804 bbl/d for the first quarter of 2025. The increase in crude oil and NGLs production before royalties for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected the acquisition in December 2024, strong utilization in the Oil Sands Mining and Upgrading segment, and thermal oil pad additions and strong drilling results in the North America Exploration and Production segment. The decrease in crude oil and NGLs production before royalties for the second quarter of 2025 from the first quarter of 2025 primarily reflected the planned turnaround at the non-operated Scotford Upgrader ("Scotford") successfully completed in the second quarter of 2025.

Annual crude oil and NGLs production for 2025 is targeted to average between 1,106,000 bbl/d and 1,142,000 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 six months ended June 30, 2025 averaged 2,429 MMcf/d, an increase of 14% from 2,129 MMcf/d for the six months ended June 30, 2024. Natural gas production before royalties for the second quarter of 2025 averaged 2,407 MMcf/d, an increase of 14% from 2,110 MMcf/d for the second quarter of 2024 and comparable with 2,451 MMcf/d for the first quarter of 2025. The increase in natural gas production before royalties for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected the acquisition in December 2024 and strong drilling results, partially offset by natural field declines.

Annual natural gas production for 2025 is targeted to average between 2,425 MMcf/d and 2,480 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 six months ended June 30, 2025 averaged 553,482 bbl/d, an increase of 10% from 502,636 bbl/d for the six months ended June 30, 2024. North America crude oil and NGLs production before royalties for the second quarter of 2025 of 545,811 bbl/d increased 9% from 499,636 bbl/d for the second quarter of 2024 and decreased 3% from 561,238 bbl/d for the first quarter of 2025. The increase in North America crude oil and NGLs production for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected the acquisition in December 2024, thermal pad additions at Primrose, and strong drilling results from heavy oil multilaterals, liquids-rich natural gas, and light oil, partially offset by natural field declines. The decrease in North America crude oil and NGLs production for the second quarter of 2025 from the first quarter of 2025 primarily reflected maintenance activities, the impact of wildfires, and natural field declines.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 274,789 bbl/d for the second quarter of 2025, an increase of 3% from 268,044 bbl/d for the second quarter of 2024 and a decrease of 3% from 284,706 bbl/d for the first quarter of 2025. The increase in thermal in situ production in the second quarter of 2025 from the second quarter of 2024 primarily reflected pad additions at Primrose, partially offset by natural field declines. The decrease in thermal in situ production in the second quarter of 2025 from the first quarter of 2025 primarily reflected natural field declines and the impact of wildfires.

Pelican Lake heavy crude oil production before royalties for the second quarter of 2025 averaged 43,078 bbl/d, a decrease of 4% from 44,839 bbl/d for the second quarter of 2024 reflecting Pelican Lake's long life low decline production, and comparable with 43,175 bbl/d for the first quarter of 2025.

North America natural gas production before royalties for the six months ended June 30, 2025 averaged 2,417 MMcf/d, an increase of 14% from 2,117 MMcf/d for the six months ended June 30, 2024. Natural gas production before royalties averaged 2,398 MMcf/d for the second quarter of 2025, an increase of 14% from 2,099 MMcf/d for the second quarter of 2024 and comparable with 2,436 MMcf/d for the first quarter of 2025. The increase in natural gas production for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected the acquisition in December 2024 and strong drilling results, partially offset by natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the six months ended June 30, 2025 averaged 529,099 bbl/d, an increase of 24% from 427,863 bbl/d for the six months ended June 30, 2024. SCO production before royalties for the second quarter of 2025 averaged 463,808 bbl/d, an increase of 13% from 410,518 bbl/d for the second quarter of 2024 and a decrease of 22% from 595,116 bbl/d for the first quarter of 2025. The increase in SCO production for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected the acquisition in December 2024, combined with strong performance and utilization at both Horizon and AOSP. The increase in SCO production for the second quarter of 2025 from the second quarter of 2024 also reflected the turnaround at Horizon in the second quarter of 2024, partially offset by the planned turnaround at Scotford completed in the second quarter of 2025. The decrease for the second quarter of 2025 from the first quarter of 2025 primarily reflected the turnaround at Scotford.

International – Exploration and Production

International crude oil and NGLs production before royalties for the six months ended June 30, 2025 averaged 13,468 bbl/d, a decrease of 45% from 24,367 bbl/d for the six months ended June 30, 2024. International crude oil and NGLs production before royalties for the second quarter of 2025 averaged 9,530 bbl/d, a decrease of 60% from 23,912 bbl/d for the second quarter of 2024 and a decrease of 45% from 17,450 bbl/d for the first quarter of 2025. The decrease in International crude oil and NGLs production for the three and six months ended June 30, 2025 from the comparable periods primarily reflected 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, maintenance activities in the North Sea in the second quarter of 2025, 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			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Crude oil and NGLs (\$/bbl) ⁽¹⁾					
Realized price ⁽²⁾	\$ 69.58	\$ 79.85	\$ 86.64	\$ 74.82	\$ 78.43
Transportation ⁽³⁾	7.65	6.40	5.98	7.01	5.31
Realized price, net of transportation ⁽²⁾	61.93	73.45	80.66	67.81	73.12
Royalties ⁽⁴⁾	9.20	14.36	17.45	11.83	14.80
Production expense ⁽⁵⁾	14.03	15.74	14.54	14.90	15.59
Netback ⁽²⁾	\$ 38.70	\$ 43.35	\$ 48.67	\$ 41.08	\$ 42.73
Natural gas (\$/Mcf) ⁽¹⁾					
Realized price ⁽⁶⁾	\$ 2.58	\$ 3.13	\$ 1.59	\$ 2.86	\$ 2.07
Transportation ⁽³⁾	0.59	0.63	0.63	0.61	0.63
Realized price, net of transportation	1.99	2.50	0.96	2.25	1.44
Royalties ⁽⁴⁾	0.08	0.11	0.02	0.10	0.06
Production expense ⁽⁵⁾	1.11	1.20	1.21	1.15	1.26
Netback ⁽⁷⁾	\$ 0.80	\$ 1.19	\$ (0.27)	\$ 1.00	\$ 0.12
Barrels of oil equivalent (\$/BOE) ⁽¹⁾					
Realized price ⁽²⁾	\$ 47.17	\$ 54.95	\$ 55.84	\$ 51.11	\$ 51.74
Transportation ⁽³⁾	5.94	5.34	5.09	5.63	4.71
Realized price, net of transportation ⁽²⁾	41.23	49.61	50.75	45.48	47.03
Royalties ⁽⁴⁾	5.58	8.76	10.53	7.19	8.97
Production expense ⁽⁵⁾	10.95	12.23	11.64	11.60	12.33
Netback ⁽²⁾	\$ 24.70	\$ 28.62	\$ 28.58	\$ 26.69	\$ 25.73

(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			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Crude oil and NGLs (\$/bbl) ⁽¹⁾					
North America ⁽²⁾	\$ 69.30	\$ 78.56	\$ 85.49	\$ 73.95	\$ 76.94
International average ⁽³⁾	\$ 91.00	\$ 107.04	\$ 115.27	\$ 103.58	\$ 114.08
North Sea ⁽³⁾	\$ 90.63	\$ 107.57	\$ 115.02	\$ 102.41	\$ 114.37
Offshore Africa ⁽³⁾	\$ 95.92	\$ 106.30	\$ 115.67	\$ 105.85	\$ 113.59
Crude oil and NGLs average ⁽²⁾	\$ 69.58	\$ 79.85	\$ 86.64	\$ 74.82	\$ 78.43
Natural gas (\$/Mcf) ^{(1) (3)}					
North America	\$ 2.54	\$ 3.06	\$ 1.53	\$ 2.80	\$ 2.02
International average	\$ 11.71	\$ 14.46	\$ 11.87	\$ 13.40	\$ 12.01
North Sea	\$ 10.00	\$ 16.43	\$ 9.79	\$ 13.86	\$ 10.58
Offshore Africa	\$ 12.47	\$ 13.65	\$ 12.24	\$ 13.20	\$ 12.23
Natural gas average	\$ 2.58	\$ 3.13	\$ 1.59	\$ 2.86	\$ 2.07
Average (\$/BOE) ^{(1) (2)}	\$ 47.17	\$ 54.95	\$ 55.84	\$ 51.11	\$ 51.74

(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 4% to average \$73.95 per bbl for the six months ended June 30, 2025 from \$76.94 per bbl for the six months ended June 30, 2024. North America realized crude oil and NGLs prices averaged \$69.30 per bbl for the second quarter of 2025, a decrease of 19% from \$85.49 per bbl for the second quarter of 2024 and a decrease of 12% from \$78.56 per bbl for the first quarter of 2025. The decrease in North America realized crude oil and NGLs prices per bbl for the three and six months ended June 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 decrease in North America realized crude oil and NGLs prices per bbl for the second quarter of 2025 from the first quarter of 2025 primarily reflected lower WTI benchmark pricing. Realized crude oil and NGLs pricing is also directly impacted by fluctuations in foreign exchange rates as sales prices are primarily denominated with reference to US dollar benchmarks. The Company continues to focus on its crude oil blending marketing strategy and in the second quarter of 2025 contributed approximately 210,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 39% to average \$2.80 per Mcf for the six months ended June 30, 2025 from \$2.02 per Mcf for the six months ended June 30, 2024. North America realized natural gas prices increased 66% to average \$2.54 per Mcf for the second quarter of 2025 from \$1.53 per Mcf for the second quarter of 2024 and decreased 17% from \$3.06 per Mcf for the first quarter of 2025. The increase in North America realized natural gas prices per Mcf for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected higher benchmark pricing. The decrease for the second quarter of 2025 from the first quarter of 2025 primarily reflected lower export pricing.

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

(Quarterly average)	Three Months Ended		
	Jun 30 2025	Mar 31 2025	Jun 30 2024
Wellhead Price ⁽¹⁾			
Light and medium crude oil and NGLs (\$/bbl)	\$ 63.96	\$ 76.47	\$ 74.90
Pelican Lake heavy crude oil (\$/bbl)	\$ 73.94	\$ 83.57	\$ 92.42
Primary heavy crude oil (\$/bbl)	\$ 72.88	\$ 81.76	\$ 91.27
Bitumen (thermal oil) (\$/bbl)	\$ 70.13	\$ 77.96	\$ 86.84
Natural gas (\$/Mcf)	\$ 2.54	\$ 3.06	\$ 1.53

(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 \$103.58 per bbl for the six months ended June 30, 2025 from \$114.08 per bbl for the six months ended June 30, 2024. International realized crude oil and NGLs prices decreased 21% to average \$91.00 per bbl for the second quarter of 2025 from \$115.27 per bbl for the second quarter of 2024 and decreased 15% from \$107.04 per bbl for the first 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, and prevailing Brent benchmark prices and foreign exchange rates at the time of lifting.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Crude oil and NGLs (\$/bbl) ⁽¹⁾					
North America	\$ 9.31	\$ 14.94	\$ 18.06	\$ 12.14	\$ 15.33
International average	\$ 0.45	\$ 1.99	\$ 2.11	\$ 1.65	\$ 2.20
North Sea	\$ 0.17	\$ 0.14	\$ 0.24	\$ 0.15	\$ 0.24
Offshore Africa	\$ 4.19	\$ 4.61	\$ 5.14	\$ 4.59	\$ 5.43
Crude oil and NGLs average	\$ 9.20	\$ 14.36	\$ 17.45	\$ 11.83	\$ 14.80
Natural gas (\$/Mcf) ⁽¹⁾					
North America	\$ 0.08	\$ 0.11	\$ 0.02	\$ 0.09	\$ 0.06
Offshore Africa	\$ 0.57	\$ 0.63	\$ 0.56	\$ 0.61	\$ 0.56
Natural gas average	\$ 0.08	\$ 0.11	\$ 0.02	\$ 0.10	\$ 0.06
Average (\$/BOE) ⁽¹⁾	\$ 5.58	\$ 8.76	\$ 10.53	\$ 7.19	\$ 8.97

(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 six months ended June 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 16% of product sales for the six months ended June 30, 2025 compared with 20% of product sales for the six months ended June 30, 2024. Crude oil and NGLs royalty rates averaged approximately 13% of product sales for the second quarter of 2025 compared with 21% for the second quarter of 2024 and 19% for the first quarter of 2025. The decrease in royalty rates for the three and six months ended June 30, 2025 from the comparable periods primarily reflected prevailing benchmark pricing and the impact of sliding scale royalty rates.

Natural gas royalty rates averaged approximately 3% of product sales for the six months ended June 30, 2025 compared with 3% of product sales for the six months ended June 30, 2024. Natural gas royalty rates averaged approximately 3% of product sales for the second quarter of 2025 compared with 1% for the second quarter of 2024 and 4% for the first quarter of 2025. The fluctuations in royalty rates for the second quarter of 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 six months ended June 30, 2025 compared with 5% of product sales for the six months ended June 30, 2024. Royalty rates as a percentage of product sales averaged approximately 5% for the second quarter of 2025 compared with 4% of product sales for the second quarter of 2024 and 4% for the first quarter of 2025. Royalty rates as a percentage of product sales reflected the timing of liftings, and the status of payout in the various fields.

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

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Crude oil and NGLs (\$/bbl) ⁽¹⁾					
North America	\$ 11.89	\$ 12.65	\$ 12.44	\$ 12.28	\$ 13.56
International average	\$ 175.70	\$ 80.63	\$ 66.83	\$ 101.16	\$ 64.00
North Sea	\$ 186.50	\$ 117.56	\$ 96.07	\$ 138.54	\$ 90.67
Offshore Africa	\$ 29.38	\$ 28.26	\$ 19.28	\$ 28.31	\$ 20.00
Crude oil and NGLs average	\$ 14.03	\$ 15.74	\$ 14.54	\$ 14.90	\$ 15.59
Natural gas (\$/Mcf) ⁽¹⁾					
North America	\$ 1.07	\$ 1.16	\$ 1.19	\$ 1.11	\$ 1.23
International average	\$ 12.20	\$ 7.60	\$ 6.51	\$ 9.37	\$ 6.08
North Sea	\$ 12.78	\$ 10.52	\$ 7.72	\$ 11.42	\$ 8.16
Offshore Africa	\$ 11.94	\$ 6.42	\$ 6.30	\$ 8.51	\$ 5.77
Natural gas average	\$ 1.11	\$ 1.20	\$ 1.21	\$ 1.15	\$ 1.26
Average (\$/BOE) ⁽¹⁾	\$ 10.95	\$ 12.23	\$ 11.64	\$ 11.60	\$ 12.33

(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 six months ended June 30, 2025 averaged \$12.28 per bbl, a decrease of 9% from \$13.56 per bbl for the six months ended June 30, 2024. North America crude oil and NGLs production expense for the second quarter of 2025 of \$11.89 per bbl decreased 4% from \$12.44 per bbl for the second quarter of 2024 and decreased 6% from \$12.65 per bbl for the first quarter of 2025. The decrease in crude oil and NGLs production expense per bbl for the six months ended June 30, 2025 from the six months ended June 30, 2024 primarily reflected higher production volumes. The decrease in crude oil and NGLs production expense per bbl for the second quarter of 2025 from the second quarter of 2024 primarily reflected higher production volumes, partially offset by higher energy costs. The decrease in crude oil and NGLs production expense per bbl for the second quarter of 2025 from the first quarter of 2025 primarily reflected lower energy costs.

North America natural gas production expense for the six months ended June 30, 2025 averaged \$1.11 per Mcf, a decrease of 10% from \$1.23 per Mcf for the six months ended June 30, 2024. North America natural gas production expense for the second quarter of 2025 of \$1.07 per Mcf decreased 10% from \$1.19 per Mcf for the second quarter of 2024 and decreased 8% from \$1.16 per Mcf for the first quarter of 2025. The decrease in natural gas production expense per Mcf for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected higher production volumes. The decrease in natural gas production expense per Mcf for the second quarter of 2025 from the first quarter of 2025 primarily reflected lower energy costs.

International

International crude oil and NGLs production expense for the six months ended June 30, 2025 averaged \$101.16 per bbl, an increase of 58% from \$64.00 per bbl for the six months ended June 30, 2024. International crude oil and NGLs production expense for the second quarter of 2025 of \$175.70 per bbl increased 163% from \$66.83 per bbl for the second quarter of 2024 and increased 118% from \$80.63 per bbl for the first quarter of 2025. The increase in crude oil and NGLs production expense per bbl for the three and six months ended June 30, 2025 from the comparable periods 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.

ADJUSTED DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
North America	\$ 1,085	\$ 1,092	\$ 956	\$ 2,177	\$ 1,897
North Sea	33	40	24	73	41
Offshore Africa	13	59	108	72	155
Depletion, depreciation and amortization	\$ 1,131	\$ 1,191	\$ 1,088	\$ 2,322	\$ 2,093
Less: Recoverability charge ⁽¹⁾	—	—	62	—	62
Adjusted depletion, depreciation and amortization ⁽²⁾	\$ 1,131	\$ 1,191	\$ 1,026	\$ 2,322	\$ 2,031
\$/BOE ⁽³⁾	\$ 12.94	\$ 13.27	\$ 12.77	\$ 13.11	\$ 12.71

(1) 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.

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

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

Adjusted depletion, depreciation and amortization expense for the six months ended June 30, 2025 averaged \$13.11 per BOE, an increase of 3% from \$12.71 per BOE for the six months ended June 30, 2024. Adjusted depletion, depreciation and amortization expense for the second quarter of 2025 averaged \$12.94 per BOE, comparable with \$12.77 per BOE for the second quarter of 2024 and \$13.27 per BOE for the first quarter of 2025. The increase in adjusted depletion, depreciation and amortization expense per BOE for the six months ended June 30, 2025 from the six months ended June 30, 2024 primarily reflected the impact of changes in North America depletion rates due to changes in reserve estimates at December 31, 2024, combined with a higher depletable base due to asset additions, partially offset by higher sales volumes.

Adjusted depletion, depreciation and amortization expense on an absolute and per BOE basis also reflects the impact of the timing of liftings from each field in the North Sea and Offshore Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
North America	\$ 53	\$ 53	\$ 57	\$ 106	\$ 115
North Sea	14	14	16	28	32
Offshore Africa	2	2	2	4	4
Asset retirement obligation accretion	\$ 69	\$ 69	\$ 75	\$ 138	\$ 151
\$/BOE ⁽¹⁾	\$ 0.79	\$ 0.77	\$ 0.95	\$ 0.78	\$ 0.95

(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 six months ended June 30, 2025 averaged \$0.78 per BOE, a decrease of 18% from \$0.95 per BOE for the six months ended June 30, 2024. Asset retirement obligation accretion expense for the second quarter of 2025 averaged \$0.79 per BOE, a decrease of 17% from \$0.95 per BOE for the second quarter of 2024 and comparable with \$0.77 per BOE for the first quarter of 2025. The decrease in asset retirement obligation accretion expense per BOE for the three and six months ended June 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.

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 463,808 bbl/d in the second quarter of 2025 primarily reflecting the planned turnaround at Scotford completed during the quarter.

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

(\$/bbl)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Realized SCO sales price ⁽¹⁾	\$ 87.22	\$ 95.52	\$ 108.81	\$ 91.88	\$ 98.18
Bitumen value for royalty purposes ⁽²⁾	\$ 64.57	\$ 73.72	\$ 82.08	\$ 69.61	\$ 72.66
Bitumen royalties ⁽³⁾	\$ 11.59	\$ 18.22	\$ 20.01	\$ 15.32	\$ 16.96
Transportation ⁽⁴⁾	\$ 3.73	\$ 3.21	\$ 2.81	\$ 3.44	\$ 2.21

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

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

(3) Calculated as royalties divided by sales volumes.

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

The realized SCO sales price averaged \$91.88 per bbl for the six months ended June 30, 2025, a decrease of 6% from \$98.18 per bbl for the six months ended June 30, 2024. The realized SCO sales price averaged \$87.22 per bbl for the second quarter of 2025, a decrease of 20% from \$108.81 per bbl for the second quarter of 2024 and a decrease of 9% from \$95.52 per bbl for the first quarter of 2025. The decrease in realized SCO sales price per bbl for the three and six months ended June 30, 2025 from the comparable periods primarily reflected lower WTI benchmark pricing.

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

Transportation expense averaged \$3.44 per bbl for the six months ended June 30, 2025, an increase of 56% from \$2.21 per bbl for the six months ended June 30, 2024. Transportation expense averaged \$3.73 per bbl for the second quarter of 2025, an increase of 33% from \$2.81 per bbl for the second quarter of 2024 and an increase of 16% from \$3.21 per bbl for the first quarter of 2025. The increase in transportation expense per bbl for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected higher volumes shipped on the TMX pipeline in 2025. The increase in transportation expense per bbl for the second quarter of 2025 from the first quarter of 2025 primarily reflected the Company's commitments on egress pipelines and lower sales volumes due to the turnaround at Scotford in the second quarter of 2025.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Production expense, excluding natural gas costs	\$ 1,085	\$ 1,135	\$ 917	\$ 2,220	\$ 1,893
Natural gas costs	35	50	24	85	74
Production expense	\$ 1,120	\$ 1,185	\$ 941	\$ 2,305	\$ 1,967

(\$/bbl)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Production expense, excluding natural gas costs ⁽¹⁾	\$ 25.71	\$ 20.95	\$ 25.29	\$ 23.03	\$ 24.41
Natural gas costs ⁽²⁾	0.82	0.93	0.66	0.88	0.95
Production expense ⁽³⁾	\$ 26.53	\$ 21.88	\$ 25.95	\$ 23.91	\$ 25.36
Sales volumes (bbl/d)	463,586	602,048	398,528	532,434	426,161

(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.

Oil Sands Mining and Upgrading production expense was \$1,120 million for the second quarter of 2025, an increase of 19% from \$941 million for the second quarter of 2024, primarily reflecting the acquisition of the additional working interest in AOSP in December 2024. Production expense decreased 5% in the second quarter of 2025 from \$1,185 million for the first quarter of 2025 primarily reflecting lower energy costs.

Production expense for the six months ended June 30, 2025 averaged \$23.91 per bbl, a decrease of 6% from \$25.36 per bbl for the six months ended June 30, 2024. Production expense for the second quarter of 2025 averaged \$26.53 per bbl, comparable with \$25.95 per bbl for the second quarter of 2024 and an increase of 21% from \$21.88 per bbl for the first quarter of 2025. The decrease in production expense per bbl for the six months ended June 30, 2025 from the six months ended June 30, 2024 primarily reflected higher production volumes. The increase in production expense per bbl for the second quarter of 2025 from the first quarter of 2025 primarily reflected lower production volumes. SCO production volumes are discussed in detail in the "Daily Production, before royalties" section of this MD&A.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Depletion, depreciation and amortization	\$ 630	\$ 675	\$ 557	\$ 1,305	\$ 1,081
\$/bbl ⁽¹⁾	\$ 14.96	\$ 12.45	\$ 15.37	\$ 13.55	\$ 13.95

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

Depletion, depreciation and amortization expense for the six months ended June 30, 2025 averaged \$13.55 per bbl, a decrease of 3% from \$13.95 per bbl for the six months ended June 30, 2024. Depletion, depreciation and amortization expense for the second quarter of 2025 of \$14.96 per bbl decreased 3% from \$15.37 per bbl for the second quarter of 2024 and increased 20% from \$12.45 per bbl for the first quarter of 2025. The decrease in depletion, depreciation and amortization expense per bbl for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected higher sales volumes, partially offset by a higher depletable base due to asset additions. The increase in depletion, depreciation and amortization expense per bbl for the second quarter of 2025 from the first quarter of 2025 primarily reflected lower sales volumes in the second quarter.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Asset retirement obligation accretion	\$ 21	\$ 22	\$ 22	\$ 43	\$ 43
\$/bbl ⁽¹⁾	\$ 0.51	\$ 0.40	\$ 0.58	\$ 0.45	\$ 0.54

(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 six months ended June 30, 2025 of \$0.45 per bbl decreased 17% from \$0.54 per bbl for the six months ended June 30, 2024. Asset retirement obligation accretion expense for the second quarter of 2025 of \$0.51 per bbl decreased 12% from \$0.58 per bbl for the second quarter of 2024 and increased 28% from \$0.40 per bbl for the first quarter of 2025. The decrease in asset retirement obligation accretion expense per bbl for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected the impact of higher sales volumes in 2025. The increase in asset retirement obligation accretion expense per bbl for the second quarter of 2025 from the first quarter of 2025 primarily reflected the impact of lower sales volumes in the second quarter.

MIDSTREAM AND REFINING

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Product sales					
Midstream activities	\$ 22	\$ 22	\$ 21	\$ 44	\$ 41
NWRP, refined product sales and other	137	221	215	358	429
Segmented revenue	159	243	236	402	470
Less:					
NWRP, refining toll	61	68	81	129	155
Midstream activities	5	5	7	10	12
Production expense	66	73	88	139	167
NWRP, feedstock costs	105	172	190	277	343
Transportation expenses	31	4	4	35	9
Depreciation	4	4	4	8	8
Segmented loss	\$ (47)	\$ (10)	\$ (50)	\$ (57)	\$ (57)

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 second quarter of 2025, production of ultra-low sulphur diesel and other refined products averaged 60,549 BOE/d (15,137 BOE/d to the Company) (three months ended March 31, 2025 – 83,863 BOE/d; 20,966 BOE/d to the Company; three months ended June 30, 2024 – 78,272 BOE/d; 19,568 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at June 30, 2025, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$504 million (December 31, 2024 – \$509 million). For the three months ended June 30, 2025, the Company's recovery of its share of unrecognized equity losses was \$24 million (three months ended March 31, 2025 – unrecognized equity losses of \$19 million; six months ended June 30, 2025 – recovery of unrecognized equity losses of \$5 million; three months ended June 30, 2024 – recovery of unrecognized equity losses of \$35 million; six months ended June 30, 2024 – recovery of unrecognized equity losses of \$39 million).

ADMINISTRATION EXPENSE

(\$ millions, except per BOE amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Administration expense	\$ 151	\$ 152	\$ 124	\$ 303	\$ 250
\$/BOE ⁽¹⁾	\$ 1.17	\$ 1.06	\$ 1.06	\$ 1.11	\$ 1.05
Sales volumes (BOE/d) ⁽²⁾	1,423,321	1,599,487	1,280,416	1,510,917	1,304,089

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

(2) Total Company sales volumes.

Administration expense for the six months ended June 30, 2025 of \$1.11 per BOE increased 6% from \$1.05 per BOE for the six months ended June 30, 2024. Administration expense for the second quarter of 2025 of \$1.17 per BOE increased 10% from \$1.06 per BOE for the second quarter of 2024 and the first quarter of 2025. The increase in administration expense per BOE for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected higher personnel costs, partially offset by higher overhead recoveries and higher sales volumes. The increase in administration expense per BOE for the second quarter of 2025 from the first quarter of 2025 reflected the impact of lower sales volumes in the second quarter.

SHARE-BASED COMPENSATION

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Share-based compensation expense (recovery)	\$ 8	\$ 26	\$ (13)	\$ 34	\$ 281

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 \$34 million of share-based compensation expense for the six months ended June 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

(\$ millions, except effective interest rate)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Interest and other financing expense	\$ 238	\$ 258	\$ 158	\$ 496	\$ 296
Less: Interest (income) and other expense ⁽¹⁾	(7)	(6)	(7)	(13)	(29)
Interest expense on long-term debt and lease liabilities ⁽¹⁾	\$ 245	\$ 264	\$ 165	\$ 509	\$ 325
Average current and long-term debt ⁽²⁾	\$ 17,552	\$ 19,147	\$ 11,568	\$ 18,349	\$ 11,582
Average lease liabilities ⁽²⁾	1,382	1,422	1,525	1,402	1,533
Average long-term debt and lease liabilities ⁽²⁾	\$ 18,934	\$ 20,569	\$ 13,093	\$ 19,751	\$ 13,115
Average effective interest rate ^{(3) (4)}	5.1%	5.0%	4.9%	5.1%	4.9%
Interest and other financing expense (\$/BOE) ⁽⁵⁾	\$ 1.84	\$ 1.79	\$ 1.35	\$ 1.81	\$ 1.25
Sales volumes (BOE/d) ⁽⁶⁾	1,423,321	1,599,487	1,280,416	1,510,917	1,304,089

(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 six months ended June 30, 2025 increased 45% to \$1.81 per BOE from \$1.25 per BOE for the six months ended June 30, 2024. Interest and other financing expense for the second quarter of 2025 increased 36% to \$1.84 per BOE from \$1.35 per BOE for the second quarter of 2024 and increased 3% from \$1.79 per BOE for the first quarter of 2025. The increase in interest and other financing expense per BOE for the three and six months ended June 30, 2025 from the comparable periods in 2024 primarily reflected higher average debt levels, including higher floating rate debt, partially offset by higher sales volumes. The increase in interest and other financing expense per BOE for the second quarter of 2025 from the first quarter of 2025 primarily reflected the impact of lower sales volumes in the second quarter of 2025, partially offset by lower average debt levels driven by movements in the US/Canadian dollar exchange rate.

The Company's average effective interest rate for the three and six months ended June 30, 2025 of 5.1% increased 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.

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Foreign currency forward contracts	\$ (115)	\$ (20)	\$ 12	\$ (135)	\$ 38
Foreign currency put options ⁽¹⁾	27	(4)	—	23	—
Natural gas financial instruments ^{(2) (3) (4)}	(1)	(3)	6	(4)	5
Net realized (gain) loss	(89)	(27)	18	(116)	43
Foreign currency forward contracts	(19)	14	3	(5)	12
Foreign currency put options ⁽¹⁾	2	(2)	—	—	—
Natural gas embedded derivative ⁽⁵⁾	(11)	—	—	(11)	—
Natural gas financial instruments ^{(2) (3) (4)}	13	(9)	(3)	4	1
Net unrealized (gain) loss	(15)	3	—	(12)	13
Net (gain) loss	\$ (104)	\$ (24)	\$ 18	\$ (128)	\$ 56

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

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

(5) 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 six months ended June 30, 2025, the net realized risk management gain was primarily related to the settlement of foreign currency forward contracts. The Company recorded a net unrealized gain of \$12 million (\$10 million after tax of \$2 million) on its risk management activities for the six months ended June 30, 2025, and a net unrealized gain of \$15 million (\$12 million after tax of \$3 million) for the second quarter of 2025 (three months ended March 31, 2025 – unrealized loss of \$3 million (\$2 million after tax of \$1 million); three months ended June 30, 2024 – \$nil; six months ended June 30, 2024 – unrealized loss of \$13 million (\$12 million after tax of \$1 million)).

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

FOREIGN EXCHANGE

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Net realized (gain) loss	\$ (142)	\$ 242	\$ 118	\$ 100	\$ 99
Net unrealized (gain) loss	(661)	(285)	(15)	(946)	254
Net (gain) loss ⁽¹⁾	\$ (803)	\$ (43)	\$ 103	\$ (846)	\$ 353

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

The net realized foreign exchange loss for the six months ended June 30, 2025 was primarily related to the foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars. The net unrealized foreign exchange gain for the six months ended June 30, 2025 was primarily related to the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at June 30, 2025 was US\$0.7341 (March 31, 2025 – US\$0.6955, June 30, 2024 – US\$0.7306).

INCOME TAXES

(\$ millions, except effective tax rates)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
North America ⁽¹⁾	\$ 529	\$ 569	\$ 548	\$ 1,098	\$ 960
North Sea	(45)	(26)	(13)	(71)	(18)
Offshore Africa	—	5	5	5	10
Current PRT – North Sea	(49)	(39)	(6)	(88)	(20)
Other taxes	3	2	(14)	5	(11)
Current income tax	438	511	520	949	921
Deferred corporate income tax	(106)	119	14	13	28
Deferred PRT – North Sea	18	9	7	27	13
Deferred income tax	(88)	128	21	40	41
Income tax	\$ 350	\$ 639	\$ 541	\$ 989	\$ 962
Earnings before taxes	\$ 2,809	\$ 3,097	\$ 2,256	\$ 5,906	\$ 3,664
Effective tax rate on net earnings ⁽²⁾	12%	21%	24%	17%	26%

(\$ millions, except effective tax rates)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Income tax	\$ 350	\$ 639	\$ 541	\$ 989	\$ 962
Tax effect on non-operating items ⁽³⁾	(1)	5	17	4	31
Current PRT – North Sea	49	39	6	88	20
Deferred PRT – North Sea	(18)	(9)	(7)	(27)	(13)
Other taxes	(3)	(2)	14	(5)	11
Effective tax on adjusted net earnings	\$ 377	\$ 672	\$ 571	\$ 1,049	\$ 1,011
Adjusted net earnings from operations ⁽⁴⁾	\$ 1,496	\$ 2,436	\$ 1,892	\$ 3,932	\$ 3,366
Adjusted net earnings from operations, before taxes	\$ 1,873	\$ 3,108	\$ 2,463	\$ 4,981	\$ 4,377
Effective tax rate on adjusted net earnings from operations ^{(5) (6)}	20%	22%	23%	21%	23%

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

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

(3) Includes the net income tax effect on PSUs, certain stock options, unrealized risk management, 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 six months ended June 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 six months ended June 30, 2025 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the decommissioning activities at the Company's platforms 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)}

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Exploration and Production					
Exploration and Evaluation Assets					
Net expenditures	\$ 5	\$ 19	\$ (4)	\$ 24	\$ 65
Net property acquisitions (dispositions)	46	(13)	—	33	—
Total Exploration and Evaluation Assets	51	6	(4)	57	65
Property, Plant and Equipment					
Net property acquisitions	178	31	4	209	1
Well drilling, completion and equipping	558	536	478	1,094	891
Production and related facilities	407	390	353	797	608
Other	16	3	13	19	25
Total Property, Plant and Equipment	1,159	960	848	2,119	1,525
Total Exploration and Production	1,210	966	844	2,176	1,590
Oil Sands Mining and Upgrading					
Project costs	96	55	123	151	185
Sustaining capital	406	216	526	622	807
Turnaround costs	174	46	114	220	125
Net property dispositions	—	—	—	—	(2)
Other	2	2	1	4	2
Total Oil Sands Mining and Upgrading	678	319	764	997	1,117
Midstream and Refining	2	2	3	4	7
Head Office	25	16	10	41	20
Net capital expenditures	\$ 1,915	\$ 1,303	\$ 1,621	\$ 3,218	\$ 2,734
Abandonment expenditures	\$ 193	\$ 188	\$ 129	\$ 381	\$ 291
By Segment					
North America	\$ 1,110	\$ 836	\$ 804	\$ 1,946	\$ 1,505
North Sea	8	3	3	11	7
Offshore Africa	92	127	37	219	78
Oil Sands Mining and Upgrading	678	319	764	997	1,117
Midstream and Refining	2	2	3	4	7
Head Office	25	16	10	41	20
Net capital expenditures	\$ 1,915	\$ 1,303	\$ 1,621	\$ 3,218	\$ 2,734

(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 \$3,218 million for the six months ended June 30, 2025 compared with \$2,734 million for the six months ended June 30, 2024. Net capital expenditures were \$1,915 million for the second quarter of 2025 compared with \$1,621 million for the second quarter of 2024 and \$1,303 million for the first quarter of 2025.

In addition, the Company reported abandonment expenditures of \$381 million for the six months ended June 30, 2025 compared with \$291 million for the six months ended June 30, 2024. Abandonment expenditures were \$193 million for the second quarter of 2025 compared with \$129 million for the second quarter of 2024 and \$188 million for the first 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. Production for 2025 is targeted between 1,510 MBOE/d and 1,555 MBOE/d. On May 7, 2025, the 2025 total capital budget was reduced by \$100 million to \$6,050 million, excluding abandonment expenditures.

In July 2025, subsequent to quarter end, the Company acquired certain producing and non-producing assets in the North America Exploration and Production segment for consideration of approximately \$750 million, subject to final closing adjustments. The 2025 capital budget did not include capital related to this acquisition.

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			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
(number of net wells)					
Net successful crude oil wells ⁽³⁾	81	74	63	155	124
Net successful natural gas wells	22	19	24	41	40
Dry wells	—	1	1	1	1
Total	103	94	88	197	165
Success rate	100%	99%	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 second quarter of 2025, the Company drilled 22 net natural gas wells, 41 net primary heavy crude oil wells, 4 net Pelican Lake heavy crude oil wells, 24 net bitumen (thermal oil) wells and 12 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)	Jun 30 2025	Mar 31 2025	Dec 31 2024	Jun 30 2024
Adjusted working capital ⁽¹⁾	\$ 102	\$ 20	\$ 174	\$ (194)
Long-term debt, net ⁽²⁾	\$ 16,979	\$ 17,335	\$ 18,688	\$ 9,234
Shareholders' equity	\$ 41,298	\$ 40,445	\$ 39,468	\$ 39,469
Debt to book capitalization ⁽²⁾	29.1%	30.0%	32.1%	19.0%
After-tax return on average capital employed ⁽³⁾	16.3%	15.3%	12.7%	16.1%

(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 June 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 expires in August 2025. 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.
 - Subsequent to June 30, 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 expires in August 2025. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

As at June 30, 2025, the Company had undrawn revolving bank credit facilities of \$4,723 million, and a fully drawn non-revolving term credit facility of \$4,000 million. Including cash and cash equivalents, the Company had approximately \$4,825 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. As at June 30, 2025, the Company had \$553 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 \$16,979 million as at June 30, 2025 (December 31, 2024 – \$18,688 million), resulting in a debt to book capitalization ratio of 29.1% (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 June 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 June 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 June 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⁾	\$	1,370	\$ 2,774	\$ 5,343	\$ 7,679
Other long-term liabilities ⁽²⁾	\$	242	\$ 151	\$ 370	\$ 621
Interest and other financing expense ⁽³⁾	\$	922	\$ 899	\$ 1,654	\$ 3,189

(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, \$238 million; one to less than two years, \$151 million; two to less than five years, \$370 million; and thereafter, \$621 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 June 30, 2025.

Share Capital

As at June 30, 2025, there were 2,090,620,000 common shares outstanding (December 31, 2024 – 2,102,996,000 common shares) and 58,657,000 stock options outstanding (December 31, 2024 – 50,806,000 stock options). As at August 5, 2025, the Company had 2,088,737,000 common shares outstanding and 57,234,000 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 six months ended June 30, 2025, the Company purchased 19,800,000 common shares at a weighted average price of \$42.70 per common share for a total cost, including tax, of \$856 million. Retained earnings were reduced by \$750 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2025, up to and including August 5, 2025, the Company purchased 2,600,000 common shares at a weighted average price of \$43.19 per common share for a total cost, including tax, of \$114 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 June 30, 2025:

(\$ millions)	Remaining 2025	2026	2027	2028	2029	Thereafter
Product transportation, purchases, and processing ⁽¹⁾	\$ 1,144	\$ 2,247	\$ 2,117	\$ 1,972	\$ 1,869	\$ 19,032
North West Redwater Partnership service toll ⁽²⁾	\$ 69	\$ 119	\$ 99	\$ 100	\$ 99	\$ 4,080
Offshore vessels and equipment	\$ 100	\$ —	\$ —	\$ —	\$ —	\$ —
Field equipment and power	\$ 28	\$ 32	\$ 29	\$ 28	\$ 27	\$ 216
Other	\$ 63	\$ 119	\$ 18	\$ 19	\$ 18	\$ 194

(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 \$1,967 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 six months ended June 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.

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Net earnings	\$ 2,459	\$ 2,458	\$ 1,715	\$ 4,917	\$ 2,702
Share-based compensation, net of tax ⁽¹⁾	6	22	(15)	28	266
Unrealized risk management (gain) loss, net of tax ⁽²⁾	(12)	2	—	(10)	12
Unrealized foreign exchange (gain) loss, net of tax ⁽³⁾	(661)	(285)	(15)	(946)	254
Realized foreign exchange (gain) loss on financing activities, net of tax ⁽⁴⁾	(216)	239	135	23	135
Loss (gain) from investments, net of tax	—	—	25	—	(50)
Gain on acquisition, net of tax ⁽⁵⁾	(80)	—	—	(80)	—
Recoverability charge, net of tax ⁽⁶⁾	—	—	47	—	47
Non-operating items, net of tax	(963)	(22)	177	(985)	664
Adjusted net earnings from operations	\$ 1,496	\$ 2,436	\$ 1,892	\$ 3,932	\$ 3,366

(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 June 30, 2025 was an expense of \$8 million (three months ended March 31, 2025 – \$26 million expense, three months ended June 30, 2024 – \$13 million recovery; six months ended June 30, 2025 – \$34 million expense; six months ended June 30, 2024 – \$281 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. Pre-tax unrealized risk management gain for the three months ended June 30, 2025 was \$15 million (three months ended March 31, 2025 – \$3 million loss, three months ended June 30, 2024 – \$nil; six months ended June 30, 2025 – \$12 million gain; six months ended June 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 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) 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.

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Cash flows from operating activities	\$ 3,114	\$ 4,284	\$ 4,084	\$ 7,398	\$ 6,952
Net change in non-cash working capital	(24)	(82)	(515)	(106)	(500)
Abandonment expenditures	193	188	129	381	291
Movements in other long-term assets ⁽¹⁾	(21)	140	(84)	119	9
Adjusted funds flow	\$ 3,262	\$ 4,530	\$ 3,614	\$ 7,792	\$ 6,752

(1) Includes the unamortized cost of contributions to the Company's employee bonus program, the accrued interest on PRT recoveries, 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.

(\$ millions, except bbl/d and \$/bbl)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Crude oil and NGLs (bbl/d)					
North America	551,248	562,183	509,674	556,685	502,148
International					
North Sea	6,778	15,665	12,682	11,197	13,075
Offshore Africa	500	11,048	7,800	5,745	7,923
Total International	7,278	26,713	20,482	16,942	20,998
Total sales volumes	558,526	588,896	530,156	573,627	523,146
Crude oil and NGLs sales ⁽¹⁾	\$ 4,655	\$ 5,624	\$ 5,484	\$ 10,279	\$ 9,989
Less: Blending and feedstock costs ⁽²⁾	1,119	1,391	1,303	2,510	2,520
Realized crude oil and NGLs sales	\$ 3,536	\$ 4,233	\$ 4,181	\$ 7,769	\$ 7,469
Realized price (\$/bbl)	\$ 69.58	\$ 79.85	\$ 86.64	\$ 74.82	\$ 78.43

(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.

(\$ millions, except BOE/d and \$/BOE)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Barrels of oil equivalent (BOE/d)					
North America	950,888	968,189	859,536	959,491	854,936
International					
North Sea	7,262	16,399	12,959	11,805	13,334
Offshore Africa	1,585	12,851	9,393	7,187	9,658
Total International	8,847	29,250	22,352	18,992	22,992
Total sales volumes	959,735	997,439	881,888	978,483	877,928
Barrels of oil equivalent sales ⁽¹⁾	\$ 5,221	\$ 6,314	\$ 5,788	\$ 11,535	\$ 10,792
Less: Blending and feedstock costs ⁽²⁾	1,119	1,391	1,303	2,510	2,520
Less: Sulphur (income) expense	(18)	(9)	3	(27)	4
Realized barrels of oil equivalent sales	\$ 4,120	\$ 4,932	\$ 4,482	\$ 9,052	\$ 8,268
Realized price (\$/BOE)	\$ 47.17	\$ 54.95	\$ 55.84	\$ 51.11	\$ 51.74

(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.

(\$ millions, except \$/bbl and royalty rates)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Crude oil and NGLs sales ⁽¹⁾	\$ 4,595	\$ 5,366	\$ 5,269	\$ 9,961	\$ 9,553
Less: Blending and feedstock costs ⁽²⁾	1,119	1,391	1,303	2,510	2,520
Realized crude oil and NGLs sales	\$ 3,476	\$ 3,975	\$ 3,966	\$ 7,451	\$ 7,033
Realized crude oil and NGLs prices (\$/bbl)	\$ 69.30	\$ 78.56	\$ 85.49	\$ 73.95	\$ 76.94
Crude oil and NGLs royalties ⁽³⁾	\$ 467	\$ 756	\$ 838	\$ 1,223	\$ 1,401
Crude oil and NGLs royalty rates	13%	19%	21%	16%	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 (a 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.

(\$ millions, except for bbl/d and \$/bbl)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
SCO sales volumes (bbl/d)	463,586	602,048	398,528	532,434	426,161
Crude oil and NGLs sales ⁽¹⁾	\$ 4,023	\$ 5,879	\$ 4,525	\$ 9,902	\$ 8,693
Less: Blending and feedstock costs ⁽²⁾	345	703	579	1,048	1,078
Realized SCO sales	\$ 3,678	\$ 5,176	\$ 3,946	\$ 8,854	\$ 7,615
Realized SCO sales price (\$/bbl)	\$ 87.22	\$ 95.52	\$ 108.81	\$ 91.88	\$ 98.18

(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.

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2025	Mar 31 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Cash flows used in investing activities	\$ 1,941	\$ 1,312	\$ 1,015	\$ 3,253	\$ 2,407
Net proceeds from investments	—	—	575	—	575
Net change in non-cash working capital	(26)	(9)	31	(35)	(248)
Net capital expenditures	1,915	1,303	1,621	3,218	2,734
Abandonment expenditures	193	188	129	381	291
Capital and abandonment expenditures	\$ 2,108	\$ 1,491	\$ 1,750	\$ 3,599	\$ 3,025

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)	Jun 30 2025	Mar 31 2025	Dec 31 2024	Jun 30 2024
Undrawn bank credit facilities	\$ 4,723	\$ 4,965	\$ 4,562	\$ 5,450
Cash and cash equivalents	102	93	131	915
Liquidity	\$ 4,825	\$ 5,058	\$ 4,693	\$ 6,365

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)	Jun 30 2025	Mar 31 2025	Dec 31 2024	Jun 30 2024
Long-term debt	\$ 17,081	\$ 17,428	\$ 18,819	\$ 10,149
Less: cash and cash equivalents	102	93	131	915
Long-term debt, net	\$ 16,979	\$ 17,335	\$ 18,688	\$ 9,234

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)	Jun 30 2025	Mar 31 2025	Dec 31 2024	Jun 30 2024
Interest adjusted after-tax return:				
Net earnings, 12 months trailing	\$ 8,321	\$ 7,577	\$ 6,106	\$ 7,673
Interest and other financing expense, net of tax, 12 months trailing ⁽¹⁾	608	546	454	461
Interest adjusted after-tax return	\$ 8,929	\$ 8,123	\$ 6,560	\$ 8,134
12 months average current portion long-term debt ⁽²⁾	\$ 1,528	\$ 1,615	\$ 1,525	\$ 1,506
12 months average long-term debt ⁽²⁾	13,174	11,878	10,642	9,651
12 months average common shareholders' equity ⁽²⁾	40,115	39,757	39,635	39,418
12 months average capital employed	\$ 54,817	\$ 53,250	\$ 51,802	\$ 50,575
After-tax return on average capital employed	16.3%	15.3%	12.7%	16.1%

(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	Jun 30 2025	Dec 31 2024
ASSETS			
Current assets			
Cash and cash equivalents		\$ 102	\$ 131
Accounts receivable		3,898	4,126
Inventory		2,667	2,793
Prepays and other		480	279
Current portion of other long-term assets	5	98	76
		7,245	7,405
Exploration and evaluation assets	2	2,658	2,526
Property, plant and equipment	3	73,331	73,414
Lease assets	4	1,310	1,394
Other long-term assets	5	724	620
		\$ 85,268	\$ 85,359
LIABILITIES			
Current liabilities			
Accounts payable		\$ 1,160	\$ 1,079
Accrued liabilities		4,188	4,525
Current income taxes payable		430	92
Current portion of long-term debt	6	1,370	2,400
Current portion of other long-term liabilities	7	1,365	1,535
		8,513	9,631
Long-term debt	6	15,711	16,419
Other long-term liabilities	7	9,197	9,302
Deferred income taxes		10,549	10,539
		43,970	45,891
SHAREHOLDERS' EQUITY			
Share capital	9	11,284	11,064
Retained earnings		29,809	28,103
Accumulated other comprehensive income	10	205	301
		41,298	39,468
		\$ 85,268	\$ 85,359

Commitments and contingencies (note 14)

Approved by the Board of Directors on August 6, 2025.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)		Three Months Ended		Six Months Ended	
		Jun 30 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
	Note				
Product sales	15	\$ 9,675	\$ 10,622	\$ 22,387	\$ 20,044
Less: royalties		(977)	(1,571)	(2,750)	(2,749)
Revenue		8,698	9,051	19,637	17,295
Expenses					
Production		2,159	1,979	4,531	4,136
Blending and feedstock		1,758	2,142	4,245	4,010
Transportation		707	513	1,360	929
Depletion, depreciation and amortization	3,4	1,765	1,649	3,635	3,182
Administration		151	124	303	250
Share-based compensation	7	8	(13)	34	281
Asset retirement obligation accretion	7	90	97	181	194
Interest and other financing expense		238	158	496	296
Risk management (gain) loss	13	(104)	18	(128)	56
Foreign exchange (gain) loss		(803)	103	(846)	353
Gain on acquisition	3	(80)	—	(80)	—
Loss (gain) from investments		—	25	—	(56)
		5,889	6,795	13,731	13,631
Earnings before taxes		2,809	2,256	5,906	3,664
Current income tax expense	8	438	520	949	921
Deferred income tax (recovery) expense	8	(88)	21	40	41
Net earnings		\$ 2,459	\$ 1,715	\$ 4,917	\$ 2,702
Net earnings per common share					
Basic	12	\$ 1.17	\$ 0.80	\$ 2.34	\$ 1.26
Diluted	12	\$ 1.17	\$ 0.80	\$ 2.34	\$ 1.25

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended		Six Months Ended	
	Jun 30 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Net earnings	\$ 2,459	\$ 1,715	\$ 4,917	\$ 2,702
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period, net of taxes of \$nil (2024 – \$nil) – three months ended; \$nil (2024 – \$nil) – six months ended	2	—	6	—
Reclassification to net earnings, net of taxes of \$nil (2024 – \$nil) – three months ended; \$1 million (2024 – \$nil) – six months ended	(2)	—	(7)	(1)
	—	—	(1)	(1)
Foreign currency translation adjustment				
Translation of net investment	(92)	17	(95)	51
Other comprehensive (loss) income, net of taxes	(92)	17	(96)	50
Comprehensive income	\$ 2,367	\$ 1,732	\$ 4,821	\$ 2,752

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Six Months Ended	
		Jun 30 2025	Jun 30 2024
Share capital	9		
Balance – beginning of period		\$ 11,064	\$ 10,712
Issued upon exercise of stock options		151	227
Previously recognized liability on stock options exercised for common shares		175	285
Purchase of common shares under Normal Course Issuer Bid		(106)	(144)
Balance – end of period		11,284	11,080
Retained earnings			
Balance – beginning of period		28,103	28,948
Net earnings		4,917	2,702
Dividends on common shares	9	(2,461)	(2,242)
Purchase of common shares under Normal Course Issuer Bid, including tax	9	(750)	(1,241)
Balance – end of period		29,809	28,167
Accumulated other comprehensive income	10		
Balance – beginning of period		301	172
Other comprehensive (loss) income, net of taxes		(96)	50
Balance – end of period		205	222
Shareholders' equity		\$ 41,298	\$ 39,469

CONSOLIDATED STATEMENTS OF CASH FLOWS

		Three Months Ended		Six Months Ended	
(millions of Canadian dollars, unaudited)	Note	Jun 30 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Operating activities					
Net earnings		\$ 2,459	\$ 1,715	\$ 4,917	\$ 2,702
Non-cash items					
Depletion, depreciation and amortization	3,4	1,765	1,649	3,635	3,182
Share-based compensation		8	(13)	34	281
Asset retirement obligation accretion		90	97	181	194
Unrealized risk management (gain) loss	13	(15)	—	(12)	13
Unrealized foreign exchange (gain) loss		(661)	(15)	(946)	254
Loss (gain) from investments		—	25	—	(50)
Gain on acquisition	3	(80)	—	(80)	—
Deferred income tax (recovery) expense		(88)	21	40	41
Realized foreign exchange on financing activities ⁽¹⁾		(216)	135	23	135
Abandonment expenditures	7	(193)	(129)	(381)	(291)
Other		21	84	(119)	(9)
Net change in non-cash working capital		24	515	106	500
Cash flows from operating activities		3,114	4,084	7,398	6,952
Financing activities					
Issuance (repayment) of bank credit facilities and commercial paper, net	6	471	—	(20)	—
Repayment of other long-term debt	6	—	(1,008)	(876)	(1,008)
Payment of lease liabilities	4	(82)	(78)	(166)	(157)
Issue of common shares on exercise of stock options	9	39	52	151	227
Dividends on common shares		(1,233)	(1,125)	(2,417)	(2,201)
Purchase of common shares under Normal Course Issuer Bid	9	(359)	(762)	(846)	(1,368)
Cash flows used in financing activities		(1,164)	(2,921)	(4,174)	(4,507)
Investing activities					
Net (expenditures) proceeds on exploration and evaluation assets	2,15	(51)	4	(57)	(65)
Net expenditures on property, plant and equipment	3,15	(1,864)	(1,625)	(3,161)	(2,669)
Net proceeds from investments		—	575	—	575
Net change in non-cash working capital		(26)	31	(35)	(248)
Cash flows used in investing activities		(1,941)	(1,015)	(3,253)	(2,407)
Increase (decrease) in cash and cash equivalents		9	148	(29)	38
Cash and cash equivalents – beginning of period		93	767	131	877
Cash and cash equivalents – end of period		\$ 102	\$ 915	\$ 102	\$ 915
Interest paid on long-term debt		\$ 237	\$ 126	\$ 494	\$ 307
Income taxes paid, net		\$ 229	\$ 437	\$ 914	\$ 635

(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 tariffs on certain goods imposed and announced by the US government and actual or potential Canadian countermeasures, both of which continue to evolve. For the six months ended June 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 it has 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	141	—	—	—	141
Transfers to property, plant and equipment	(6)	—	—	—	(6)
Foreign exchange adjustments	—	—	(3)	—	(3)
At June 30, 2025	\$ 2,543	\$ —	\$ 45	\$ 70	2,658

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	2,185	11	219	997	4	41	3,457
Transfers from exploration and evaluation assets	6	—	—	—	—	—	6
Derecognitions ⁽¹⁾	(312)	—	—	(304)	—	—	(616)
Foreign exchange adjustments and other	—	(531)	(283)	—	—	—	(814)
At June 30, 2025	\$ 90,843	\$ 9,211	\$ 4,959	\$ 58,038	\$ 499	\$ 648	164,198
Accumulated depletion and depreciation							
At December 31, 2024	\$ 62,010	\$ 9,392	\$ 3,885	\$ 12,765	\$ 229	\$ 470	88,751
Expense	2,128	60	60	1,212	8	15	3,483
Derecognitions ⁽¹⁾	(312)	—	—	(304)	—	—	(616)
Foreign exchange adjustments and other	(5)	(516)	(227)	(3)	—	—	(751)
At June 30, 2025	\$ 63,821	\$ 8,936	\$ 3,718	\$ 13,670	\$ 237	\$ 485	90,867
Net book value							
At June 30, 2025	\$ 27,022	\$ 275	\$ 1,241	\$ 44,368	\$ 262	\$ 163	73,331
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 or disposal.

In June 2025, the Company acquired certain producing and non-producing assets 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 purchase 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 the total purchase consideration.

If the acquisition had been completed on January 1, 2025, the Company estimates that pro forma revenue would have increased by approximately \$300 million and pro forma net operating income (revenue less production and transportation expenses) would have increased by approximately \$186 million for the six months ended June 30, 2025. Including the impact of depletion, depreciation and amortization, the Company estimates earnings before taxes would have increased by approximately \$122 million for the six months ended June 30, 2025. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2025, or of future results. Pro forma results are based on historical information and reflect actual production in the period available for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

In July 2025, subsequent to quarter end, the Company acquired certain producing and non-producing assets in the North America Exploration and Production segment for consideration of approximately \$750 million, subject to final closing adjustments. Net assets acquired primarily include property, plant and equipment and exploration and evaluation assets. The Company also assumed associated asset retirement obligations.

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	14	83	2	41	140
Depreciation	(43)	(79)	(18)	(12)	(152)
Derecognitions	—	(29)	(29)	—	(58)
Foreign exchange adjustments and other	(3)	(5)	(3)	(3)	(14)
At June 30, 2025	\$ 720	\$ 438	\$ 16	\$ 136	\$ 1,310

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at June 30, 2025 were as follows:

	Jun 30 2025	Dec 31 2024
Lease liabilities	\$ 1,380	\$ 1,464
Less: current portion	238	255
	\$ 1,142	\$ 1,209

Total cash outflows for leases for the three months ended June 30, 2025, including payments related to short-term leases not reported as lease assets, were \$378 million (three months ended June 30, 2024 – \$319 million; six months ended June 30, 2025 – \$732 million; six months ended June 30, 2024 – \$655 million). Interest expense on leases for the three months ended June 30, 2025 was \$15 million (three months ended June 30, 2024 – \$18 million; six months ended June 30, 2025 – \$31 million; six months ended June 30, 2024 – \$35 million).

5. OTHER LONG-TERM ASSETS

	Jun 30 2025	Dec 31 2024
Long-term prepayments, contracts and other ⁽¹⁾	\$ 358	\$ 313
Prepaid cost of service tolls	193	166
Long-term inventory	252	204
Risk management (note 13)	19	13
	822	696
Less: current portion	98	76
	\$ 724	\$ 620

(1) Includes physical product sales contracts, accrued interest on PRT recoveries, 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 June 30, 2025, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$504 million (December 31, 2024 – \$509 million). For the three months ended June 30, 2025, the Company's recovery of its share of unrecognized equity losses was \$24 million (six months ended June 30, 2025 – recovery of its share of unrecognized equity losses of \$5 million; three months ended June 30, 2024 – recovery of unrecognized equity losses of \$35 million; six months ended June 30, 2024 – recovery of unrecognized equity losses of \$39 million).

6. LONG-TERM DEBT

	Jun 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 (June 30, 2025 – US\$3,470 million; December 31, 2024 – US\$3,393 million)	4,727	4,888
Commercial paper (June 30, 2025 – US\$406 million; December 31, 2024 – US\$467 million)	553	672
US dollar debt securities (June 30, 2025 – US\$7,650 million; December 31, 2024 – US\$8,250 million)	10,420	11,883
	17,166	18,909
Less: original issue discounts, net ⁽¹⁾	12	12
transaction costs ^{(1) (2)}	73	78
	17,081	18,819
Less: current portion of commercial paper	553	672
current portion of long-term debt ^{(1) (2)}	817	1,728
	\$ 15,711	\$ 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 June 30, 2025, the Company had undrawn revolving bank credit facilities of \$4,723 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 June 30, 2025, the Company had \$553 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 June 30, 2025 was 5.2% (June 30, 2024 – \$nil outstanding), and on total long-term debt outstanding for the six months ended June 30, 2025 was 5.0% (June 30, 2024 – 4.9%).

As at June 30, 2025, letters of credit and guarantees aggregating to \$872 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 expires in August 2025. 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

Subsequent to June 30, 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 expires in August 2025. 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.

7. OTHER LONG-TERM LIABILITIES

	Jun 30 2025	Dec 31 2024
Asset retirement obligations	\$ 8,672	\$ 8,607
Lease liabilities (note 4)	1,380	1,464
Share-based compensation	388	620
Transportation and processing contracts	47	58
Risk management (note 13)	4	8
Other	71	80
	10,562	10,837
Less: current portion	1,365	1,535
	\$ 9,197	\$ 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:

	Jun 30 2025	Dec 31 2024
Balance – beginning of period	\$ 8,607	\$ 7,690
Liabilities incurred	18	28
Liabilities acquired, net	350	171
Liabilities settled	(381)	(646)
Asset retirement obligation accretion	181	389
Revision of cost, inflation, and timing estimates ⁽¹⁾	—	417
Change in discount rates	—	419
Foreign exchange adjustments	(103)	139
Balance – end of period	8,672	8,607
Less: current portion	788	787
	\$ 7,884	\$ 7,820

(1) Includes normal course revisions of cost, inflation, and timing estimates, as well as revisions related to cost estimate increases on future abandonment of the Ninian field 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.

	Jun 30 2025	Dec 31 2024
Balance – beginning of period	\$ 620	\$ 780
Share-based compensation expense	34	279
Cash payment for stock options surrendered and PSUs vested	(92)	(84)
Transferred to common shares	(175)	(358)
Other	1	3
Balance – end of period	388	620
Less: current portion	316	463
	\$ 72	\$ 157

8. INCOME TAXES

The provision for income tax was as follows:

Expense (recovery)	Three Months Ended		Six Months Ended	
	Jun 30 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Current corporate income tax – North America ⁽¹⁾	\$ 529	\$ 548	\$ 1,098	\$ 960
Current corporate income tax – North Sea	(45)	(13)	(71)	(18)
Current corporate income tax – Offshore Africa	—	5	5	10
Current PRT ⁽²⁾ – North Sea	(49)	(6)	(88)	(20)
Other taxes	3	(14)	5	(11)
Current income tax	438	520	949	921
Deferred corporate income tax	(106)	14	13	28
Deferred PRT ⁽²⁾ – North Sea	18	7	27	13
Deferred income tax	(88)	21	40	41
Income tax	\$ 350	\$ 541	\$ 989	\$ 962

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

(2) Petroleum Revenue Tax.

9. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued Common Shares	Six Months Ended Jun 30, 2025	
	Number of shares (thousands)	Amount
Balance – beginning of period	2,102,996	\$ 11,064
Issued upon exercise of stock options	7,424	151
Previously recognized liability on stock options exercised for common shares	—	175
Purchase of common shares under Normal Course Issuer Bid	(19,800)	(106)
Balance – end of period	2,090,620	\$ 11,284

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 six months ended June 30, 2025, the Company purchased 19,800,000 common shares at a weighted average price of \$42.70 per common share for a total cost, including tax, of \$856 million. Retained earnings were reduced by \$750 million, representing the excess of the purchase price of common shares over their average carrying value.

Subsequent to June 30, 2025, up to and including August 5, 2025, the Company purchased 2,600,000 common shares at a weighted average price of \$43.19 per common share for a total cost, including tax, of \$114 million.

Share-Based Compensation – Stock Options

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

	Six Months Ended Jun 30, 2025	
	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of period	50,806	\$ 33.90
Granted	17,379	43.58
Exercised for common shares	(7,424)	20.33
Surrendered for cash settlement	(405)	20.87
Forfeited	(1,699)	37.80
Outstanding – end of period	58,657	\$ 38.46
Exercisable – end of period	11,842	\$ 32.30

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:

	Jun 30 2025	Jun 30 2024
Derivative financial instruments designated as cash flow hedges	\$ 69	\$ 71
Foreign currency translation adjustment	136	151
	\$ 205	\$ 222

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 June 30, 2025, the ratio was within the target range at 29.1%.

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.

	Jun 30 2025	Dec 31 2024
Long-term debt	\$ 17,081	\$ 18,819
Less: cash and cash equivalents	102	131
Long-term debt, net	\$ 16,979	\$ 18,688
Total shareholders' equity	\$ 41,298	\$ 39,468
Debt to book capitalization	29.1%	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 June 30, 2025, the Company was in compliance with this covenant.

12. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	Jun 30 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Weighted average common shares outstanding – basic (thousands of shares)	2,093,135	2,133,374	2,096,817	2,137,730
Effect of dilutive stock options (thousands of shares)	6,530	16,089	7,508	16,647
Weighted average common shares outstanding – diluted (thousands of shares)	2,099,665	2,149,463	2,104,325	2,154,377
Net earnings	\$ 2,459	\$ 1,715	\$ 4,917	\$ 2,702
Net earnings per common share – basic	\$ 1.17	\$ 0.80	\$ 2.34	\$ 1.26
– diluted	\$ 1.17	\$ 0.80	\$ 2.34	\$ 1.25

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)	Jun 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)}	13	(6)
Foreign exchange	(3)	1
Other comprehensive income	—	1
Balance – end of period	15	5
Less: current portion	4	5
	\$ 11	\$ —

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

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

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

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

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

	Three Months Ended		Six Months Ended	
	Jun 30 2025	Jun 30 2024	Jun 30 2025	Jun 30 2024
Net realized risk management (gain) loss	\$ (89)	\$ 18	\$ (116)	\$ 43
Net unrealized risk management (gain) loss	(15)	—	(12)	13
	\$ (104)	\$ 18	\$ (128)	\$ 56

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:

	Jun 30, 2025	
	Carrying amount	Level 1 Fair Value
Fixed rate long-term debt ^{(1) (2)}	\$ 11,801	\$ 11,869

(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, probability factor, and 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 second quarter of 2025, the Company recognized an unrealized gain of \$11 million and a corresponding risk management asset.

The Level 3 fair value measurements of the embedded derivative could be materially impacted by a change in the discount rate and movements in natural gas prices. The following table summarizes the impact to fair value 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)	Jun 30, 2025
JKM price	
Increase (decrease) of US\$0.10/MMBtu	37 / (37)
Discount rate	
Increase (decrease) of 1 %	(67) / 77

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 June 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 June 30, 2025, the Company had US\$2,143 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\$1,535 million were designated as derivatives held for trading (December 31, 2024 – US\$1,521 million) and US\$608 million were designated as cash flow hedges (December 31, 2024 – US\$666 million).

As at June 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 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 June 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 June 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	\$	1,160	\$ —	\$ —	\$ —
Accrued liabilities	\$	4,188	\$ —	\$ —	\$ —
Long-term debt ⁽¹⁾	\$	1,370	\$ 2,774	\$ 5,343	\$ 7,679
Other long-term liabilities ⁽²⁾	\$	242	\$ 151	\$ 370	\$ 621
Interest and other financing expense ⁽³⁾	\$	922	\$ 899	\$ 1,654	\$ 3,189

(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, \$238 million; one to less than two years, \$151 million; two to less than five years, \$370 million; and thereafter, \$621 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 June 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 June 30, 2025:

	Remaining 2025	2026	2027	2028	2029	Thereafter
Product transportation, purchases, and processing ⁽¹⁾	\$ 1,144	\$ 2,247	\$ 2,117	\$ 1,972	\$ 1,869	\$ 19,032
North West Redwater Partnership service toll ⁽²⁾	\$ 69	\$ 119	\$ 99	\$ 100	\$ 99	\$ 4,080
Offshore vessels and equipment	\$ 100	\$ —	\$ —	\$ —	\$ —	\$ —
Field equipment and power	\$ 28	\$ 32	\$ 29	\$ 28	\$ 27	\$ 216
Other	\$ 63	\$ 119	\$ 18	\$ 19	\$ 18	\$ 194

(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 \$1,967 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

	North America						North Sea						Offshore Africa						Total Exploration and Production						
	Three Months Ended		Six Months Ended		Jun 30		Three Months Ended		Six Months Ended		Jun 30		Three Months Ended		Six Months Ended		Jun 30		Three Months Ended		Six Months Ended		Jun 30		
	2025	2024	2025	2024	2025	2024	2025	2024	2025	2024	2025	2024	2025	2024	2025	2024	2025	2024	2025	2024	2025	2024	2025	2024	
(millions of Canadian dollars, unaudited)																									
Segmented product sales																									
Crude oil and NGLs	\$ 4,595	\$ 5,269	\$ 9,961	\$ 9,553	\$ 56	\$ 133	\$ 208	\$ 272	\$ 4	\$ 82	\$ 110	\$ 164	\$ 4,655	\$ 5,484	\$ 10,279	\$ 9,989									
Natural gas	555	292	1,226	777	3	2	9	3	8	10	21	23	566	304	1,256	803									
Other income and revenue ⁽¹⁾	16	(5)	33	(7)	—	—	—	4	—	1	1	1	—	—	34	(2)									
Total segmented product sales	5,166	5,556	11,220	10,323	59	135	217	279	12	93	132	188	5,237	5,784	11,569	10,790									
Less: royalties	(487)	(841)	(1,268)	(1,424)	—	(1)	—	(1)	(1)	(4)	(6)	(9)	(488)	(846)	(1,274)	(1,434)									
Segmented revenue	4,679	4,715	9,952	8,899	59	134	217	278	11	89	126	179	4,749	4,938	10,295	9,356									
Segmented expenses																									
Production	829	804	1,723	1,713	118	112	288	218	8	19	43	40	955	935	2,054	1,971									
Blending and feedstock	1,119	1,303	2,510	2,520	—	—	—	—	—	—	—	—	—	—	2,510	2,520									
Transportation	518	404	994	746	1	5	4	6	—	—	—	—	—	—	998	752									
Depletion, depreciation and amortization	1,085	956	2,177	1,897	33	24	73	41	13	108	72	155	1,131	1,088	2,322	2,093									
Asset retirement obligation accretion	53	57	106	115	14	16	28	32	2	2	4	4	69	75	138	151									
Risk management loss (gain) (commodity derivatives)	1	3	(11)	6	—	—	—	—	—	—	—	—	—	—	(11)	6									
Gain on acquisition	(80)	—	(80)	—	—	—	—	—	—	—	—	—	—	—	(80)	—									
Total segmented expenses	3,525	3,527	7,419	6,997	166	157	393	297	23	129	119	199	3,714	3,813	7,931	7,493									
Segmented earnings (loss)	\$ 1,154	\$ 1,188	\$ 2,533	\$ 1,902	\$ (107)	\$ (23)	\$ (176)	\$ (19)	\$ (12)	\$ (40)	\$ 7	\$ (20)	\$ 1,035	\$ 1,125	\$ 2,364	\$ 1,863									
Non-segmented expenses																									
Administration																									
Share-based compensation																									
Interest and other financing expense																									
Risk management (gain) loss (other)																									
Foreign exchange (gain) loss																									
Loss (gain) from investments																									
Total non-segmented (earnings) expenses																									
Earnings before taxes																									
Current income tax																									
Deferred income tax																									
Net earnings																									

[illegible]

(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.

Capital Expenditures ⁽¹⁾

Six Months Ended

	Jun 30, 2025			Jun 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	\$ 57	\$ 78	\$ 135	\$ 68	\$ (42)	\$ 26
Offshore Africa	—	—	—	(3)	(62)	(65)
	57	78	135	65	(104)	(39)
Property, plant and equipment						
Exploration and Production						
North America	1,889	(10)	1,879	1,437	(259)	1,178
North Sea	11	—	11	7	—	7
Offshore Africa	219	—	219	81	—	81
	2,119	(10)	2,109	1,525	(259)	1,266
Oil Sands Mining and Upgrading	997	(304)	693	1,117	(341)	776
Midstream and Refining	4	—	4	7	—	7
Head Office	41	—	41	20	—	20
	3,161	(314)	2,847	2,669	(600)	2,069
	\$ 3,218	\$ (236)	\$ 2,982	\$ 2,734	\$ (704)	\$ 2,030

(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

	Jun 30 2025	Dec 31 2024
Exploration and Production		
North America	\$ 32,921	\$ 32,670
North Sea	882	702
Offshore Africa	1,363	1,412
Other	14	31
Oil Sands Mining and Upgrading	48,737	49,221
Midstream and Refining	1,071	1,099
Head Office	280	224
	\$ 85,268	\$ 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 July 2023. 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 June 30, 2025:

Interest coverage (times)	
Net earnings ⁽¹⁾	14.0x
Adjusted funds flow ⁽²⁾	23.0x

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

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

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CORPORATE INFORMATION

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N. Murray Edwards, O.C.
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Ambassador Gordon D. Giffin
Wilfred A. Gobert
Christine M. Healy
Steve W. Laut
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Scott G. Stauth
David A. Tuer
Annette M. Verschuren, O.C.

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President
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Robin S. Zabek
Chief Operating Officer, Exploration and Production
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Senior Vice-President, Exploration
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Vice-President, Marketing
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Vice-President, Drilling, Completions and Asset Retirement
Stephanie A. Graham
Corporate Secretary and Associate General Counsel, Canada

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

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

Stock Listing

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

Registrar and Transfer Agent

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