Canadian Natural

FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2024 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2024 FIRST QUARTER RESULTS

Canadian Natural's President, Scott Stauth, commented on the Company's first quarter results, "Canadian Natural is a world class company and during our 35 years of operations, we've delivered significant value, including recently reaching a position where, commencing in 2024, we are returning 100% of our free cash flow to our shareholders. Crude oil price forecasts have strengthened for the remainder of 2024, including improvements in West Texas Intermediate ("WTI"), Western Canadian Select ("WCS") and Synthetic Crude Oil ("SCO") pricing over those prices experienced in the first quarter of 2024, driving significant targeted free cash flow generation going forward.

Canadian Natural's large, unique and diversified asset base provides a key competitive advantage enabling us to effectively allocate capital across our asset base and manage the pace and timing of development activities, maximizing value for our shareholders. We are executing on our 2024 plan which is strategically weighted to longer cycle thermal development projects in the first half of the year and shorter cycle growth projects in the second half of the year, which aligns with increased market egress and improved forward strip crude oil pricing. As a result, we target to finish the year with strong exit rates as conventional activity ramps up in the second half of the year.

In Oil Sands Mining and Upgrading, at the Horizon site, we are well prepared for 2024 turnaround activity and final tie-ins of the reliability enhancement project in the second quarter of the year, which will be followed by targeted strong production in the second half of the year with high upgrader utilization. Through optimization efforts and early turnaround work done in early 2024, we have reduced the Horizon turnaround to 28 days from 30 days and improved the commissioning schedule for the reliability enhancement project. These optimizations will advance and shorten commissioning timing after the turnaround to support high targeted utilization and production rates in the second half of the year.

We have a defined path to reduce our environmental footprint and continue delivering sustainable, responsibly produced energy that the world needs. We are committed to supporting Canada's and Alberta's climate goals and have robust environmental targets, including net zero greenhouse gas ("GHG") emissions for the oil sands by 2050. We are uniquely positioned with diverse, long life low decline assets, which are ideal for applying GHG reduction technologies and providing industry leading environmental performance. It is important to continue working together with the Canadian and Alberta governments to make the Pathways Alliance a transformative industry collaboration and achieve meaningful GHG reductions in Canada. We believe Canadian energy is one of the most responsibly produced sources of energy in the world and should be the preferred energy choice."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, also added “In Q1/24, we delivered strong financial results, including adjusted net earnings of approximately $1.5 billion and adjusted funds flow of $3.1 billion, which drove significant returns to shareholders totaling $1.7 billion in the quarter. Commencing in 2024, we are returning 100% of free cash flow to shareholders, as per our free cash flow allocation policy, and continue to manage the allocation on a forward looking annual basis.

At Canadian Natural, our culture of continuous improvement and employee ownership alignment with shareholders drives our teams to create significant value across all areas of the Company. Our effective and efficient operations combined with our flexible capital allocation maximizes value for our shareholders."

HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Mar 31 2024	Dec 31 2023	Mar 31 2023
Net earnings	**$ 987**	$ 2,627	$ 1,799
Per common share – basic	**$ 0.92**	$ 2.43	$ 1.63
– diluted	**$ 0.91**	$ 2.41	$ 1.62
Adjusted net earnings from operations (1)	**$ 1,474**	$ 2,546	$ 1,881
Per common share – basic (2)	**$ 1.38**	$ 2.36	$ 1.71
– diluted (2)	**$ 1.37**	$ 2.34	$ 1.69
Cash flows from operating activities	**$ 2,868**	$ 4,815	$ 1,295
Adjusted funds flow (1)	**$ 3,138**	$ 4,419	$ 3,429
Per common share – basic (2)	**$ 2.93**	$ 4.09	$ 3.12
– diluted (2)	**$ 2.91**	$ 4.05	$ 3.08
Cash flows used in investing activities	**$ 1,392**	$ 946	$ 1,153
Net capital expenditures (3)	**$ 1,113**	$ 975	$ 1,257
Abandonment expenditures	**$ 162**	$ 149	$ 137
Daily production, before royalties			
Natural gas (MMcf/d)	**2,147**	2,231	2,139
Crude oil and NGLs (bbl/d)	**975,668**	1,047,541	962,908
Equivalent production (BOE/d) (4)	**1,333,502**	1,419,313	1,319,391

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2024 dated May 1, 2024.

(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2024 dated May 1, 2024.

(3) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2023 and has been updated for all periods presented. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2024 dated May 1, 2024.

(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, effective and efficient operations, makes our business unique, robust and sustainable. In Q1/24, the Company generated strong financial results, including:
  - Net earnings of approximately $1.0 billion and adjusted net earnings from operations of approximately $1.5 billion.
  - Cash flows from operating activities of approximately $2.9 billion.
  - Adjusted funds flow of approximately $3.1 billion.
- Canadian Natural continues to maintain a strong balance sheet and financial flexibility, with approximately $6.8 billion in liquidity(1) as at March 31, 2024.
  - Subsequent to quarter end, the Company repaid US$0.5 billion of 3.8% debt securities due April 15, 2024.
- Canadian Natural achieved its $10 billion net debt level at year end 2023 and is returning 100% of free cash flow(1) in 2024 to shareholders, per the Company's free cash flow allocation policy. The Company will manage the allocation of free cash flow on a forward looking annual basis, while managing working capital and cash management as required.

(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 months ended March 31, 2024 dated May 1, 2024.

- Canadian Natural continues to focus on safe, effective and efficient operations, and delivered quarterly average production in Q1/24 of 1,333,502 BOE/d, consisting of total liquids production of 975,668 bbl/d and natural gas production of 2,147 MMcf/d.
- The Company is targeting strong production from its Oil Sands Mining and Upgrading assets in the second half of the year, as we optimize turnaround activity, complete final tie-ins and advance commissioning of the reliability enhancement project in Q2/24.
- Canadian Natural has significant growth opportunities across its asset base, including sustainable production enhancements at its Oil Sands Mining and Upgrading operations.
  - Near-term projects include the reliability enhancement project at Horizon, which targets to increase the two-year average SCO capacity by approximately 14,000 bbl/d by extending the turnaround schedule to once every two years. Additionally, the debottlenecking project at the Scotford Upgrader targets to add incremental capacity at the Athabasca Oil Sands Project ("AOSP") of approximately 5,600 bbl/d net to Canadian Natural.
  - Medium-term projects include the Naphtha Recovery Unit Tailings Treatment ("NRUTT") project at Horizon, which targets to add incremental production of approximately 6,300 bbl/d of SCO, reduce GHG emissions and lower reclamation costs.
  - Long-term projects at our Oil Sands operations include combining In-Pit Extraction Process ("IPEP") and Paraffinic Froth Treatment ("PFT") that have the potential to add approximately 195,000 bbl/d of additional annual bitumen production, reduce GHG emissions and lower reclamation costs.
- The Company's 2024 development plan has conventional activity strategically weighted to the second half of 2024 to better align with increased market egress and improved crude oil pricing, maximizing value for our shareholders. Following completion of the Trans Mountain Expansion ("TMX") pipeline, there will be ample egress and optionality for our crude oil products.
  - Strong free cash flow generation is targeted in the last nine months of the 2024, given improved crude oil forward strip pricing as of April 30, 2024:
    - WTI of US$79.95/bbl, an improvement of approximately US$3/bbl from US$76.97/bbl experienced in Q1/24.
    - SCO at a US$2.47/bbl price premium to WTI, an improvement of approximately US$10/bbl from a US$7.54/bbl discount experienced in Q1/24.
    - WCS differential strengthening to a discount to WTI of US$13.17/bbl, an improvement of approximately US$6/bbl from the US$19.34/bbl discount experienced in Q1/24.
- The Company continues to evaluate and implement opportunities to maximize netbacks through the diversification of sales and optimized blending and transportation options through diverse market access. Canadian Natural has optionality for crude oil exports, including the following pipeline commitments:
  - In Q1/24, the Company increased its commitment on Flanagan South by 55,000 bbl/d to 77,500 bbl/d, further expanding the Company's heavy oil diversification and market access to the United States Gulf Coast ("USGC").
  - 94,000 bbl/d on Trans Mountain Expansion ("TMX") pipeline that creates additional crude oil market diversification opportunities on the west coast, both by land and by water.
  - 10,000 bbl/d on the Base Keystone Pipeline, with direct access to the USGC.

RETURNS TO SHAREHOLDERS

- Canadian Natural has a strong history of growing its sustainable dividend for 24 consecutive years and commencing in 2024, we are now returning 100% of free cash flow to shareholders.
  - Returns to shareholders in Q1/24 were strong, totaling approximately $1.7 billion, comprised of $1.1 billion of dividends and $0.6 billion through the repurchase and cancellation of approximately 6.7 million common shares at a weighted average price of $90.78 per share.
  - Year to date in 2024, up to and including May 1, 2024, the Company has returned a total of approximately $3.1 billion directly to shareholders through $2.2 billion in dividends and $0.9 billion through the repurchase and cancellation of approximately 9.6 million common shares.

- Subsequent to quarter end, the Company declared a quarterly cash dividend on its common shares of $1.05 (one dollar and five cents) per common share on a pre-stock split basis or $0.525 (fifty-two and one half cents) per common share after the two for one share split of the common shares, subject to shareholder approval at the Company's Annual and Special Meeting of Shareholders on May 2, 2024. The quarterly dividend will be payable on July 5, 2024 to shareholders of record at the close of business on June 17, 2024.
    - As previously announced on February 29, 2024, the Board of Directors increased the quarterly dividend by 5% to $1.05 per common share. This demonstrates the confidence that the Board of Directors has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline reserves and asset base. The Company's leading track record of dividend increases continues, with 2024 being the 24th consecutive year of dividend increases with a compound annual growth rate ("CAGR") of 21% over that time.

- On February 28, 2024, Canadian Natural's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval at the Company's Annual and Special Meeting of Shareholders on May 2, 2024. The Company will also be required to obtain all regulatory approvals, including TSX approval.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

Canadian Natural has a balanced and diverse portfolio of assets, primarily Canadian-based, with international exposure in the UK section 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 79% of total budgeted liquids production in 2024, 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 land base 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 and has an extensive infrastructure network, 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	Three Months Ended			
	Mar 31, 2024		Mar 31, 2023	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil [(1)]	**62**	**61**	88	83
Natural gas	**23**	**16**	26	21
Dry	**—**	**—**	2	2
Subtotal	**85**	**77**	116	106
Stratigraphic test / service wells	**452**	**386**	455	394
Total	**537**	**463**	571	500
Success rate (excluding stratigraphic test / service wells)		**100%**		98%

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 77 net crude oil and natural gas producer wells in Q1/24 compared to 106 net wells in Q1/23, a decrease of 29 net wells over this time period. This decrease in drilling activity reflects the Company's strategic decision to focus on longer cycle development opportunities in the first half of 2024 and shorter cycle development opportunities in the second half of 2024, as previously outlined in the Company's 2024 budget press release.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Crude oil and NGLs production (bbl/d)	**237,481**	243,157	234,465
Net wells targeting crude oil	**38**	42	60
Net successful wells drilled	**38**	42	58
Success rate	**100%**	100%	97%

- North America E&P liquids production, excluding thermal in situ, averaged 237,481 bbl/d in Q1/24, comparable to Q1/23 levels. As previously outlined in the 2024 budget, the Company has strategically allocated capital for its conventional assets to the latter part of 2024 to better align with incremental market egress, driving strong targeted 2024 exit rates.
  - Primary heavy crude oil production averaged 78,431 bbl/d in Q1/24, comparable to Q1/23 levels, reflecting strong results from the Company's multilateral wells in the Mannville and Clearwater fairways which offset natural field declines.
    - The Company is targeting to drill 148 net multilateral wells in 2024, 12 more than budgeted, as we are shifting certain dry natural gas activity to these higher returning multilateral heavy oil wells. The majority of this activity is strategically planned for the second half of 2024.
    - Operating costs(1) in the Company's primary heavy crude oil operations averaged $19.16/bbl (US$14.21/bbl) in Q1/24, a decrease of 11% from Q1/23 levels, primarily reflecting lower energy costs.
  - Pelican Lake production averaged 45,145 bbl/d in Q1/24, a decrease of 6% from Q1/23 levels, reflecting low natural field declines from this long life low decline asset.
    - Operating costs at Pelican Lake averaged $9.75/bbl (US$7.23/bbl) in Q1/24, comparable to Q1/23 levels.
  - North America light crude oil and NGLs production averaged 113,905 bbl/d in Q1/24, an increase of 5% from Q1/23 production which was impacted by a third party pipeline outage. Production in Q1/24 reflects strong drilling results from the Company's liquids-rich Montney and Deep Basin assets partially offset by natural field declines.
    - Operating costs in the Company's North America light crude oil and NGLs operations averaged $15.25/bbl (US$11.31/bbl) in Q1/24, a decrease of 18% from Q1/23 levels, reflecting increased production and lower energy costs.

North America Natural Gas

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Natural gas production (MMcf/d)	**2,135**	2,218	2,127
Net wells targeting natural gas	**16**	9	21
Net successful wells drilled	**16**	9	21
Success rate	**100%**	100%	100%

- Canadian Natural's North America natural gas production averaged 2,135 MMcf/d in Q1/24, comparable to Q1/23 production which was impacted by a third party pipeline outage. Production in Q1/24 reflects strong results from the Company's capital efficient drill to fill development plan, offset by natural field declines.
  - North America natural gas operating costs averaged $1.27/Mcf in Q1/24, a decrease of 11% from Q1/23 levels, primarily reflecting lower energy costs.

(1) Calculated as production expense divided by respective sales volumes. Natural gas and NGLs production volumes approximate sales volumes.

Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Bitumen production (bbl/d)	**268,155**	278,422	242,884
Net wells targeting bitumen	**23**	—	25
Net successful wells drilled	**23**	—	25
Success rate	**100%**	—%	100%

- Thermal in situ long life low decline production averaged 268,155 bbl/d in Q1/24, an increase of 10% from Q1/23 levels, driven by strong execution on Cyclic Steam Stimulation ("CSS") and Steam Assisted Gravity Drainage ("SAGD") pad developments in 2023.
  - Thermal in situ operating costs averaged $14.05/bbl (US$10.42/bbl) in Q1/24, a decrease of 12% from Q1/23 levels, primarily reflecting higher production volumes and lower energy costs.
- The Company successfully completed the planned turnaround at Jackfish ahead of schedule in April 2024, and has an upcoming turnaround at Kirby North in May 2024. As a result of completing the turnaround at Jackfish ahead of schedule, the total impact to Q2/24 average production is now targeted to be approximately 15,300 bbl/d, an improvement from the previous target of 17,100 bbl/d.
- Canadian Natural has decades of strong capital efficient growth opportunities on its long life low decline thermal in situ assets. As outlined in our 2024 budget, we continue to develop these assets in a disciplined manner to deliver safe and reliable thermal in situ production with the following opportunities:
  - At Primrose, the Company is currently drilling two CSS pads which are targeted to come on production in Q2/25. At Wolf Lake, the Company recently drilled one SAGD pad which is targeted to come on production in Q1/25.
  - At Jackfish, the first of two SAGD pads that were drilled in 2023 has ramped up to its targeted full production capacity in April 2024, ahead of budget. The second pad is targeted to ramp up to its full production capacity in Q4/24, supporting continued high utilization rates at the Jackfish facilities. Additionally, the Company is targeting to drill one SAGD pad at Jackfish in the second half of 2024, with production from this pad targeted to come on in Q3/25.
- 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 GHG intensities by 40% to 50% and optimizing solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
  - At Kirby North, the commercial scale solvent SAGD pad development is approximately 90% complete and the Company is targeting to begin solvent injection in July 2024.
  - At Primrose, the Company is continuing to use its solvent enhanced oil recovery pilot in the steam flood area to optimize solvent efficiency and to further evaluate the commercial development opportunity.

North America Oil Sands Mining and Upgrading

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Synthetic crude oil production (bbl/d) (1)(2)	**445,209**	500,133	458,228

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

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

- Canadian Natural remains focused on safe, reliable, effective and efficient operations of its world class Oil Sands Mining and Upgrading assets. In Q1/24, the Company delivered average production of 445,209 bbl/d of high value SCO, a decrease of 3% from Q1/23 levels. Production in Q1/24 reflected planned and unplanned maintenance activities, including the advancement of the Scotford Upgrader planned turnaround to March 2024 from April 2024. These activities in Q1/24 reduced Oil Sands Mining and Upgrading production by approximately 45,000 bbl/d of

SCO from what would have been achieved otherwise. Through the actions discussed below and other optimization efforts, the Company is targeting to recover these daily production volumes in the last three quarters of 2024.

- Oil Sands Mining and Upgrading operating costs are top tier, averaging $24.85/bbl (US$18.43/bbl) in Q1/24, comparable to Q1/23 levels.

▪ Canadian Natural has the following upcoming turnarounds, including schedule optimizations, planned at our Oil Sands Mining and Upgrading operations:

- At Horizon, a planned turnaround is targeted to begin on May 15, 2024. Through continuous improvement, optimization efforts and early turnaround work done in Q1/24 during unplanned maintenance activities, the Company has reduced the targeted duration of the turnaround to 28 days from 30 days.
    - Additionally, following the turnaround, the Company is optimizing the commissioning schedule of the reliability enhancement project, which is targeted to increase Q3/24 SCO production.
- At AOSP, a 49 day turnaround is targeted to begin in September 2024, when the Scotford Upgrader will run at reduced rates, impacting annual production by approximately 11,000 bbl/d.

▪ The Company continues to progress sustainable production enhancements at both Horizon and AOSP.

- At Horizon, the Company targets to complete the remaining components and tie-ins related to the reliability enhancement project during the planned turnaround in Q2/24.
    - This project targets to increase capacity of the zero decline, high value SCO production over a two year timeframe by shifting the planned turnarounds to once every two years from the current annual cycle, reducing downtime and increasing overall reliability. In 2025, annual production is targeted to increase by approximately 28,000 bbl/d, with the two year average annual SCO capacity targeted to increase by approximately 14,000 bbl/d.
- At the Scotford Upgrader, a debottlenecking project, which targets to add incremental capacity at AOSP of approximately 5,600 bbl/d net to Canadian Natural, is targeted to be completed during the planned Fall 2024 turnaround.
- At Horizon, the Company is progressing the Naphtha Recovery Unit Tailings Treatment ("NRUTT") project that targets incremental production of approximately 6,300 bbl/d of SCO following mechanical completion in Q3/27. This project is targeted to reduce GHG emissions, equivalent to 6% of Horizon's total Scope 1 emissions, and will result in lower reclamation costs.

International Exploration and Production

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Crude oil production (bbl/d)	**24,823**	25,829	27,331
Natural gas production (MMcf/d)	**12**	13	12

▪ International E&P crude oil production volumes averaged 24,823 bbl/d in Q1/24, a decrease of 9% from Q1/23 levels, reflecting natural field declines and maintenance activities.

MARKETING

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Benchmark Commodity Prices			
WTI benchmark price (US$/bbl) (1)	**$ 76.97**	$ 78.33	$ 76.11
WCS heavy differential (discount) to WTI (US$/bbl) (1)	**$ (19.34)**	$ (21.90)	$ (24.74)
WCS heavy differential as a percentage of WTI (%) (1)	**25%**	28%	33%
Condensate benchmark price (US$/bbl)	**$ 72.79**	$ 76.22	$ 79.83
SCO price (US$/bbl) (1)	**$ 69.43**	$ 78.64	$ 78.18
SCO premium (discount) to WTI (US$/bbl) (1)	**$ (7.54)**	$ 0.31	$ 2.07
AECO benchmark price (C$/GJ)	**$ 1.94**	$ 2.52	$ 4.12
Realized Prices			
Exploration & Production liquids realized price (C$/bbl) (2)(3)(4)(5)	**$ 70.01**	$ 69.39	$ 58.85
SCO realized price (C$/bbl) (1)(3)(4)(5)	**$ 88.84**	$ 98.73	$ 96.07
Natural gas realized price (C$/Mcf) (4)	**$ 2.55**	$ 2.80	$ 4.27

(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 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 months ended March 31, 2024 dated May 1, 2024.

- Canadian Natural has a balanced and diverse product mix of natural gas, NGLs, heavy crude oil, light crude oil, bitumen and SCO.
- WTI prices averaged US$76.97/bbl in Q1/24, comparable to both Q4/23 and Q1/23, although the global crude oil market continues to be impacted by heightened geopolitical tensions.
  - WTI forward strip pricing(1) has strengthened for the last nine months of 2024, averaging US$79.95/bbl, an improvement of approximately US$3/bbl from Q1/24.
- SCO pricing averaged US$69.43/bbl in Q1/24, representing a US$7.54/bbl price discount to WTI, compared to a US$2.07/bbl price premium to WTI in Q1/23. The lower SCO price in Q1/24 was primarily driven by egress constraints in the Western Canadian Sedimentary Basin ("WCSB").
  - SCO forward strip pricing(1) has strengthened for the last nine months of 2024, averaging a price premium to WTI of US$2.47/bbl, an improvement of approximately US$10/bbl from Q1/24.
- The average WCS differential to WTI of US$19.34/bbl in Q1/24 has strengthened from both comparable periods, primarily reflecting the anticipated startup of TMX and stronger US Gulf Coast heavy oil pricing due to lower Mexican imports.
  - WCS forward strip pricing(1) has strengthened for the last nine months of 2024, averaging US$13.17/bbl, an improvement of approximately US$6/bbl from Q1/24.
- The Company continues to evaluate and implement opportunities to maximize netbacks through the diversification of sales and optimized blending and transportation options through diverse market access. Canadian Natural has optionality for crude oil exports, including the following pipeline commitments:
  - In Q1/24, the Company increased its commitment on Flanagan South by 55,000 bbl/d to 77,500 bbl/d, further expanding the Company's heavy oil diversification and market access to the USGC.
  - 94,000 bbl/d on TMX pipeline that creates additional crude oil market diversification opportunities on the west coast, both by land and by water.
  - 10,000 bbl/d on the Base Keystone Pipeline, with direct access to the USGC.

(1) Forward strip pricing as of April 30, 2024.

- The North West Redwater ("NWR") refinery primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 78,569 bbl/d in Q1/24.
- AECO natural gas prices in Q1/24 compared to Q1/23 and Q4/23 reflect lower NYMEX benchmark pricing, increased production in the WCSB and higher storage inventories resulting from mild winter weather.
  - In 2024, the Company is targeting to use the equivalent of approximately 38% of its budgeted natural gas production in its operations, with approximately 25% targeted to be sold at AECO/Station 2 pricing, and approximately 37% 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.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE HIGHLIGHTS

Canada and Canadian Natural are well positioned to deliver affordable, reliable, safe and responsibly produced energy that the world needs, through leading ESG performance. Canadian Natural's diverse portfolio is supported by a significant amount of long life low decline assets which have low risk, high value reserves that require low maintenance capital. This allows the Company to remain flexible with our capital allocation and creates an ideal opportunity to pilot and apply technologies for GHG emissions reductions. Canadian Natural continues to invest in a range of technologies to reduce emissions, such as solvents for enhanced recovery and Carbon Capture, Utilization and Storage ("CCUS") projects. Our culture of continuous improvement provides a significant advantage to delivering on our strategy of investing in GHG technologies across our assets, including opportunities for methane emissions reduction.

Environmental Targets

Canadian Natural is committed to reducing our environmental footprint and as previously announced, has committed to the following environmental targets:

- 40% reduction in corporate Scope 1 and Scope 2 absolute GHG emissions by 2035, from a 2020 baseline
- 50% reduction in North America E&P (including thermal in situ) methane emissions by 2030, from a 2016 baseline
- 40% reduction in thermal in situ fresh water usage intensity by 2026, from a 2017 baseline
- 40% reduction in mining fresh river water usage intensity by 2026, from a 2017 baseline

Canadian Natural has a defined pathway to achieve long-term emissions reductions with an integrated GHG emissions management strategy that includes ongoing investments in technology and innovation while transferring technology across the Company. The areas of focus include, but are not limited to: carbon capture, sequestration/ storage and utilization, the use of solvents, energy/steam efficiencies, methane reduction, and tailings and water management.

Pathways Alliance

The six major oil sands companies in the Pathways Alliance ("Pathways"), including Canadian Natural, operate approximately 95% of Canada's oil sands production. The goal of this unique alliance is to work together with governments to achieve net zero emissions from oil sands operations by 2050, support Canada in meeting its climate commitments and be the preferred source of crude oil globally. Pathways has a defined plan, including its foundational carbon capture and storage ("CCS") project involving a CO_2 transportation line connecting Fort McMurray and Cold Lake to a carbon sequestration hub.

Pathways continues to work together with governments on the necessary co-investment and regulatory certainty needed to proceed. As a step in moving the project forward, Canadian Natural, on behalf of the Pathways Alliance, commenced regulatory applications in March 2024 to the Alberta Energy Regulator for the proposed CO_2 Transportation Network and Storage Hub. Project engineering and environmental field programs are on track to meet timelines. Multiple feasibility studies on phase-one capture facilities, with engineering and design work continue to progress. Stakeholder engagement and consultation is ongoing with Indigenous and local communities in northern Alberta related to the Pathways CCS project.

Government Support for Emissions Reductions and Carbon Capture, Utilization and Storage

The Government of Canada announced a Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap on December 7, 2023 with plans to publish draft regulations by mid-2024. The framework proposes to cap and cut emissions from the oil and natural gas sector through implementation of a national cap-and-trade system. The oil and natural gas sector has made significant progress in GHG emissions reductions along with investments in technology and innovation that have been enabled under existing carbon pricing systems. As such, the proposed oil and natural gas sector emissions cap is unnecessary, exceedingly complex and undermines the investor confidence required for large-scale, long-term emission reduction initiatives.

Canadian Natural is a leader in CCUS and GHG reduction projects and sees many opportunities to work collaboratively with industry peers and governments to advance investments in CCUS and to achieve meaningful GHG emissions reductions in support of Canada's climate goals. The Government of Canada has proposed an investment tax credit ("ITC") for CCUS projects for all sectors across Canada that would offer a refundable ITC of up to 50% on capture equipment and 37.5% on qualified carbon transportation, storage or usage equipment from 2022 to 2030. Additionally, the Government of Alberta announced it would provide a 12% tax credit on eligible capital costs associated with building new CCUS projects. It remains important for governments to work together with industry to ensure that policy and regulatory frameworks deliver the required support to enable CCUS project development.

Canadian Natural will continue to provide input to government on the importance of balancing environmental and economic objectives along with being able to support Canada’s allies with energy security. By working together, industry and governments have the opportunity to help achieve climate goals, meet economic objectives and support Canada’s role in energy security.

ADVISORY

Special Note Regarding Non-GAAP and Other Financial Measures

This document 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. These financial measures are used by the Company to evaluate its financial performance, financial position or 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 Company's financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this document, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below as well as in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2024, dated May 1, 2024.

Break-even WTI Price

The break-even 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 break-even WTI price a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. The break-even 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 excludes net acquisition costs. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for more details on net capital expenditures.

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.

Free Cash Flow Policy in 2023 and 2024

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 target amount of shareholder returns after dividends. The calculation in determining free cash flow varies depending on the Company's net debt position, and as a result of achieving $10 billion in net debt at the end of 2023, the Company's free cash flow calculation has changed in 2024, when compared to 2023 as follows:

- **Allocation of Free Cash Flow in 2024**

  As net debt of $10 billion was achieved at the end of 2023, commencing in 2024, the Company will target to return 100% of free cash flow to shareholders. 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.

  The Company's free cash flow for the three months ended March 31, 2024 is shown below:

($ millions)	Three Months Ended **Mar 31 2024**
Adjusted funds flow (1)	**$ 3,138**
Less: Dividends on common shares	**1,076**
Net capital expenditures (2)	**1,113**
Abandonment expenditures	**162**
Free cash flow	**$ 787**

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, which are provided in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2024, dated May 1, 2024.
(2) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2024, dated May 1, 2024.

- **Allocation of Free Cash Flow in 2023**

  When net debt was between $10 billion and $15 billion, as was the case in 2023, approximately 50% of free cash flow was allocated to shareholder returns and 50% was allocated to the balance sheet, less strategic growth/acquisition opportunities. In 2023, free cash flow of $6.9 billion was calculated as adjusted funds flow of $15.3 billion less dividends on common shares of $3.9 billion, base capital expenditures of $4.0 million and abandonment expenditures of $0.5 billion.

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)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Long-term debt	**$ 11,040**	$ 10,799	$ 12,024
Less: cash and cash equivalents	**767**	877	92
Long-term debt, net	**$ 10,273**	$ 9,922	$ 11,932

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", "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 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, 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, the Pelican Lake water and polymer flood projects, the Kirby thermal oil sands project, the Jackfish thermal oil sands project 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 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 impact of the Pathways Alliance ("Pathways") initiative and activities, government support for Pathways and the ability to achieve net zero emissions from oil sands production, 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 armed conflicts in the Middle East, the impact of the Russian invasion of 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; political uncertainty, including 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 Company's ability to implement strategies and leverage technologies to meet climate change initiatives and emissions targets on the expected timelines; 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 and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); interpretations of applicable tax 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, 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 Currency, Financial Information and Production

This MD&A should be read in conjunction with the Company's unaudited interim consolidated financial statements (the "financial statements") for the three months ended March 31, 2024, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2023. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three months ended March 31, 2024 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 months ended March 31, 2024 in relation to the first quarter of 2023 and the fourth quarter of 2023. 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, 2023, is available on SEDAR+ at www.sedarplus.ca, and on EDGAR at www.sec.gov. Information on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated May 1, 2024.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Mar 31 2024	Dec 31 2023	Mar 31 2023
Product sales [(1)]	**$ 9,422**	$ 10,679	$ 9,548
Crude oil and NGLs	**$ 8,676**	$ 9,829	$ 8,412
Natural gas	**$ 529**	$ 603	$ 851
Net earnings	**$ 987**	$ 2,627	$ 1,799
Per common share – basic	**$ 0.92**	$ 2.43	$ 1.63
– diluted	**$ 0.91**	$ 2.41	$ 1.62
Adjusted net earnings from operations [(2)]	**$ 1,474**	$ 2,546	$ 1,881
Per common share – basic [(3)]	**$ 1.38**	$ 2.36	$ 1.71
– diluted [(3)]	**$ 1.37**	$ 2.34	$ 1.69
Cash flows from operating activities	**$ 2,868**	$ 4,815	$ 1,295
Adjusted funds flow [(2)]	**$ 3,138**	$ 4,419	$ 3,429
Per common share – basic [(3)]	**$ 2.93**	$ 4.09	$ 3.12
– diluted [(3)]	**$ 2.91**	$ 4.05	$ 3.08
Cash flows used in investing activities	**$ 1,392**	$ 946	$ 1,153
Net capital expenditures [(4)]	**$ 1,113**	$ 975	$ 1,257
Abandonment expenditures	**$ 162**	$ 149	$ 137

(1) Further details related to product sales are disclosed in note 17 to the financial statements.

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

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

(4) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2023 and has been updated for all periods presented. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings and Adjusted Net Earnings from Operations

Net earnings for the first quarter of 2024 were $987 million compared with $1,799 million for the first quarter of 2023 and $2,627 million for the fourth quarter of 2023. Net earnings for the first quarter of 2024 included non-operating losses, net of tax, of $487 million compared with non-operating losses of $82 million for the first quarter of 2023 and non-operating income of $81 million for the fourth quarter of 2023 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the (gain) loss from investments, and a recoverability charge in the fourth quarter of 2023 relating to the increase in estimate of future abandonment costs for the planned decommissioning activities at the Ninian field in the North Sea. Excluding these items, adjusted net earnings from operations for the first quarter of 2024 were $1,474 million compared with $1,881 million for the first quarter of 2023 and $2,546 million for the fourth quarter of 2023.

The decrease in net earnings and adjusted net earnings from operations for the first quarter of 2024 from the first quarter of 2023 primarily reflected:

- lower realized SCO sales pricing [(1)] in the Oil Sands Mining and Upgrading segment; and
- lower realized natural gas pricing in the North America Exploration and Production segment;

partially offset by:

- higher crude oil and NGLs sales volumes and netbacks [(1)] in the North America Exploration and Production segment.

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

The decrease in net earnings and adjusted net earnings from operations for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected:

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

The impacts of share-based compensation, risk management activities, fluctuations in foreign exchange rates, and the (gain) loss from investment also contributed to the movements in net earnings. These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the first quarter of 2024 were $2,868 million compared with $1,295 million for the first quarter of 2023 and $4,815 million for the fourth quarter of 2023. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted related to the fluctuations in adjusted net earnings from operations, together with the impact of net changes in non-cash working capital.

Adjusted funds flow for the first quarter of 2024 was $3,138 million compared with $3,429 million for the first quarter of 2023 and $4,419 million for the fourth quarter of 2023. 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 the share bonus program, accrued interest on the deferred Petroleum Revenue Tax ("PRT") recovery, and prepaid cost of service tolls.

Production Volumes

Crude oil and NGLs production before royalties for the first quarter of 2024 of 975,668 bbl/d was comparable with 962,908 bbl/d for the first quarter of 2023, and decreased 7% from 1,047,541 bbl/d for the fourth quarter of 2023. Natural gas production before royalties for the first quarter of 2024 of 2,147 MMcf/d was comparable with 2,139 MMcf/d for the first quarter of 2023, and decreased 4% from 2,231 MMcf/d for the fourth quarter of 2023. Total production before royalties for the first quarter of 2024 of 1,333,502 BOE/d was comparable with 1,319,391 BOE/d for the first quarter of 2023, and decreased 6% from 1,419,313 BOE/d for the fourth quarter of 2023. 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 [(1)] averaged $70.01 per bbl for the first quarter of 2024, an increase of 19% from $58.85 per bbl for the first quarter of 2023, and comparable with $69.39 per bbl for the fourth quarter of 2023. The realized natural gas price decreased 40% to average $2.55 per Mcf for the first quarter of 2024 from $4.27 per Mcf for the first quarter of 2023, and decreased 9% from $2.80 per Mcf for the fourth quarter of 2023. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price decreased 8% to average $88.84 per bbl for the first quarter of 2024 from $96.07 per bbl for the first quarter of 2023, and decreased 10% from $98.73 per bbl for the fourth quarter of 2023. The Company's realized pricing reflected 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 $16.66 per bbl for the first quarter of 2024, comparable with $16.93 per bbl for the first quarter of 2023, and an increase of 11% from $15.05 per bbl for the fourth quarter of 2023. Natural gas production expense [1] averaged $1.30 per Mcf for the first quarter of 2024, a decrease of 12% from $1.47 per Mcf for the first quarter of 2023, and an increase of 15% from $1.13 per Mcf for the fourth quarter of 2023. In the Oil Sands Mining and Upgrading segment, production expense [1] averaged $24.85 per bbl for the first quarter of 2024, comparable with $25.06 per bbl for the first quarter of 2023, and an increase of 19% from $20.96 per bbl for the fourth quarter of 2023. 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)	**Mar 31 2024**	Dec 31 2023	Sep 30 2023	Jun 30 2023
Product sales [1]	**$ 9,422**	$ 10,679	$ 11,762	$ 8,846
Crude oil and NGLs	**$ 8,676**	$ 9,829	$ 10,944	$ 8,115
Natural gas	**$ 529**	$ 603	$ 599	$ 522
Net earnings	**$ 987**	$ 2,627	$ 2,344	$ 1,463
Net earnings per common share				
– basic	**$ 0.92**	$ 2.43	$ 2.15	$ 1.34
– diluted	**$ 0.91**	$ 2.41	$ 2.13	$ 1.32

($ millions, except per common share amounts)	Mar 31 2023	Dec 31 2022	Sep 30 2022	Jun 30 2022
Product sales [1]	$ 9,548	$ 11,012	$ 12,574	$ 13,812
Crude oil and NGLs	$ 8,412	$ 9,508	$ 11,001	$ 11,727
Natural gas	$ 851	$ 1,287	$ 1,342	$ 1,605
Net earnings	$ 1,799	$ 1,520	$ 2,814	$ 3,502
Net earnings per common share				
– basic	$ 1.63	$ 1.37	$ 2.52	$ 3.04
– diluted	$ 1.62	$ 1.36	$ 2.49	$ 3.00

(1) Further details related to product sales for the three months ended March 31, 2024 and 2023 are disclosed in note 17 to the financial statements.

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

- **Crude oil pricing** – Fluctuations in global supply/demand including crude oil production levels from OPEC+ and its impact on world supply, the impact of geopolitical and market uncertainties (including those due to the Russian invasion of Ukraine and conflict in the Middle East) on worldwide benchmark pricing, the impact of shale oil production in North America, 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, third-party pipeline maintenance and outages, the impact of geopolitical and market uncertainties, the impact of seasonal conditions, and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production from the Kirby and Jackfish thermal oil sands projects, fluctuations in production due to the cyclic nature of the Primrose thermal oil projects, fluctuations in the Company's drilling program in the North America Exploration and Production segment, natural decline rates, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and wildfires and a third-party pipeline outage in 2023 in the North America Exploration and Production segment. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.

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

- **Natural gas sales volumes** – Fluctuations in production due to the Company's drilling program in the North America Exploration and Production segment, natural decline rates, the impact of seasonal conditions, wildfires and a third-party pipeline outage in 2023 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 and pitstops 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, 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 and pitstops in the Oil Sands Mining and Upgrading segment, a recoverability charge at 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 December 31, 2022 relating to the de-booking of reserves at the Ninian field in the North Sea.
- **Share-based compensation** – Fluctuations due to the measurement of fair market value of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Interest expense** – Fluctuations due to changing long-term debt levels, and the impact of movements in benchmark interest rates on outstanding floating rate long-term debt and accrued interest on the deferred PRT recovery.
- **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, partially offset by the impact of any cross currency swap hedges outstanding.
- **(Gain) loss from investment** – Fluctuations due to the (gain) loss from the investment in PrairieSky Royalty Ltd. shares.

BUSINESS ENVIRONMENT

Risks and Uncertainties

Global crude oil benchmark pricing for the first quarter of 2024 remained relatively flat compared to 2023 as weaker demand growth outlooks were offset by increased geopolitical tensions in the Middle East, combined with continued supply quota management by OPEC+. Although inflationary pressures are easing, the Company has experienced and may continue to experience inflationary pressures on its operating and capital expenditures in addition to higher than normal fluctuations in commodity prices and interest rates.

Liquidity

As at March 31, 2024, the Company had undrawn revolving bank credit facilities of $5,450 million. Including cash and cash equivalents and short-term investments, the Company had approximately $6,817 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

	Three Months Ended		
(Average for the period)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
WTI benchmark price (US$/bbl)	**$ 76.97**	$ 78.33	$ 76.11
Dated Brent benchmark price (US$/bbl)	**$ 83.23**	$ 84.06	$ 81.24
WCS Heavy Differential from WTI (US$/bbl)	**$ 19.34**	$ 21.90	$ 24.74
SCO price (US$/bbl)	**$ 69.43**	$ 78.64	$ 78.18
Condensate benchmark price (US$/bbl)	**$ 72.79**	$ 76.22	$ 79.83
NYMEX benchmark price (US$/MMBtu)	**$ 2.24**	$ 2.87	$ 3.43
AECO benchmark price (C$/GJ)	**$ 1.94**	$ 2.52	$ 4.12
US/Canadian dollar average exchange rate (US$)	**$ 0.7415**	$ 0.7341	$ 0.7393

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. Product revenue continued to be impacted by changes in the Canadian dollar as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks.

Crude oil sales contracts in North America are typically based on WTI benchmark pricing. WTI averaged US$76.97 per bbl for the first quarter of 2024, comparable with US$76.11 per bbl for the first quarter of 2023, and US$78.33 per bbl for the fourth quarter of 2023.

Crude oil sales contracts for the Company's International segments are typically based on Brent pricing, which is representative of international markets and overall global supply and demand. Brent averaged US$83.23 per bbl for the first quarter of 2024, comparable with US$81.24 per bbl for the first quarter of 2023, and US$84.06 per bbl for the fourth quarter of 2023.

WTI and Brent benchmark pricing was relatively flat for the first quarter of 2024 from the comparable periods in 2023, as OPEC+ continued to manage its supply quota. Weaker demand growth outlooks in the first quarter of 2024 were offset by shipping disruptions in the Red Sea and geopolitical tensions in the Middle East.

The WCS Heavy Differential averaged US$19.34 per bbl for the first quarter of 2024, compared with US$24.74 per bbl for the first quarter of 2023, and US$21.90 per bbl for the fourth quarter of 2023. The narrowing of the WCS Heavy Differential for the first quarter of 2024 from the first quarter of 2023 primarily reflected stronger US Gulf Coast heavy oil pricing due to lower Mexican imports, partially offset by egress constraints in the Western Canadian Sedimentary Basin ("WCSB"). The narrowing of the WCS Heavy Differential for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected the anticipated startup of the Trans Mountain Expansion ("TMX") pipeline, partially offset by unplanned refinery outages in the US Midwest.

The SCO price averaged US$69.43 per bbl for the first quarter of 2024, a decrease of 11% from US$78.18 per bbl for the first quarter of 2023, and a decrease of 12% from US$78.64 per bbl for the fourth quarter of 2023. The decrease in SCO pricing for the first quarter of 2024 from the comparable periods in 2023 primarily reflected the weakening of the SCO differential from WTI, reflecting strong production levels and egress constraints in the WCSB.

NYMEX natural gas prices averaged US$2.24 per MMBtu for the first quarter of 2024, a decrease of 35% from US$3.43 per MMBtu for the first quarter of 2023, and a decrease of 22% from US$2.87 per MMBtu for the fourth quarter of 2023. The decrease in NYMEX natural gas prices for first quarter of 2024 from the comparable periods in 2023 primarily reflected mild winter weather that reduced heating demand and drove North American and European inventory levels above the five year average. Additionally, reduced Liquefied Natural Gas ("LNG") exports from the US Gulf Coast, as a result of maintenance, also contributed to downward pressure on prices.

AECO natural gas prices averaged $1.94 per GJ for the first quarter of 2024, a decrease of 53% from $4.12 per GJ for the first quarter of 2023, and a decrease of 23% from $2.52 per GJ for the fourth quarter of 2023. The decrease in AECO natural gas prices for first quarter of 2024 from the comparable periods in 2023 primarily reflected decreased NYMEX benchmark pricing, increased production in the WCSB, and higher storage inventories resulting from mild winter weather in 2024.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**505,636**	521,579	477,349
North America – Oil Sands Mining and Upgrading (1)	**445,209**	500,133	458,228
International – Exploration and Production			
North Sea	**12,433**	12,616	13,240
Offshore Africa	**12,390**	13,213	14,091
Total International (2)	**24,823**	25,829	27,331
Total Crude oil and NGLs	**975,668**	1,047,541	962,908
Natural gas (MMcf/d) (3)			
North America	**2,135**	2,218	2,127
International			
North Sea	**1**	2	3
Offshore Africa	**11**	11	9
Total International	**12**	13	12
Total Natural gas	**2,147**	2,231	2,139
Total Barrels of oil equivalent (BOE/d)	**1,333,502**	1,419,313	1,319,391
Product mix			
Light and medium crude oil and NGLs	**11%**	10%	10%
Pelican Lake heavy crude oil	**3%**	3%	4%
Primary heavy crude oil	**6%**	6%	6%
Bitumen (thermal oil)	**20%**	20%	18%
Synthetic crude oil (1)	**33%**	35%	35%
Natural gas	**27%**	26%	27%
Percentage of product sales (1) (4) (5)			
Crude oil and NGLs	**94%**	94%	90%
Natural gas	**6%**	6%	10%

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

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

(3) Natural gas production volumes approximate sales volumes.

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

(5) Excluding Midstream and Refining revenue.

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**413,752**	431,091	396,482
North America – Oil Sands Mining and Upgrading [1]	**370,837**	443,535	411,434
International – Exploration and Production			
North Sea	**12,406**	12,590	13,240
Offshore Africa	**11,755**	11,917	12,740
Total International	**24,161**	24,507	25,980
Total Crude oil and NGLs	**808,750**	899,133	833,896
Natural gas (MMcf/d)			
North America	**2,049**	2,148	1,988
International			
North Sea	**1**	2	3
Offshore Africa	**11**	11	9
Total International	**12**	13	12
Total Natural gas	**2,061**	2,161	2,000
Total Barrels of oil equivalent (BOE/d)	**1,152,258**	1,259,297	1,167,300

(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 for the first quarter of 2024 averaged 975,668 bbl/d, comparable with 962,908 bbl/d for the first quarter of 2023, and a decrease of 7% from 1,047,541 bbl/d for the fourth quarter of 2023. The decrease in crude oil and NGLs production before royalties for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected lower production in the Oil Sands Mining and Upgrading segment due to planned and unplanned maintenance in the first quarter of 2024, including the advancement of turnaround activities at the non-operated Scotford Upgrader ("Scotford") from April into March. The decrease for the first quarter of 2024 from the fourth quarter of 2023 also reflected lower thermal in situ production due to the cyclical nature of steaming at Primrose in the North America Exploration and Production segment.

Annual crude oil and NGLs production for 2024 is targeted to average between 977,000 bbl/d and 1,008,000 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 for the first quarter of 2024 averaged 2,147 MMcf/d, comparable with 2,139 MMcf/d for the first quarter of 2023, and a decrease of 4% from 2,231 MMcf/d for the fourth quarter of 2023. The decrease in natural gas production for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected natural field declines and the impact of seasonality, partially offset by the execution of the planned drilling program.

Annual natural gas production for 2024 is targeted to average between 2,120 MMcf/d and 2,230 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 for the first quarter of 2024 of 505,636 bbl/d increased 6% from 477,349 bbl/d for the first quarter of 2023, and decreased 3% from 521,579 bbl/d for the fourth quarter of 2023. The increase in North America crude oil and NGLs production for the first quarter of 2024 from the first quarter of 2023 primarily reflected pad additions in thermal in situ during the second half of 2023, partially offset by natural field declines. The decrease for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected lower thermal in situ production due to the cyclical nature of steaming at Primrose, and natural field declines in conventional exploration and production, partially offset by the execution of the planned drilling program.

The Company's thermal in situ assets continued to demonstrate long life, low decline production before royalties, averaging 268,155 bbl/d for the first quarter of 2024, an increase of 10% from 242,884 bbl/d for the first quarter of 2023, and a decrease of 4% from 278,422 bbl/d for the fourth quarter of 2023. The increase in thermal in situ production in the first quarter of 2024 from the first quarter of 2023 primarily reflected pad additions in the second half of 2023. The decrease in thermal in situ production in the first quarter of 2024 from the fourth quarter of 2023 primarily reflected the cyclical nature of steaming at Primrose.

Pelican Lake heavy crude oil production before royalties for the first quarter of 2024 averaged 45,145 bbl/d, a decrease of 6% from 48,244 bbl/d for the first quarter of 2023, and comparable with 46,046 bbl/d for the fourth quarter of 2023, demonstrating Pelican Lake's long life low decline production.

North America natural gas production for the first quarter of 2024 averaged 2,135 MMcf/d, comparable with 2,127 MMcf/d for the first quarter of 2023, and a decrease of 4% from 2,218 MMcf/d for the fourth quarter of 2023. The decrease in North America natural gas production for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected natural field declines and the impact of seasonality, partially offset by the execution of the planned drilling program.

North America – Oil Sands Mining and Upgrading

SCO production for the first quarter of 2024 averaged 445,209 bbl/d, comparable with 458,228 bbl/d for the first quarter of 2023, and a decrease of 11% from 500,133 bbl/d for the fourth quarter of 2023. The decrease for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected planned and unplanned maintenance in the first quarter of 2024, including the advancement of turnaround activities at Scotford from April into March.

International – Exploration and Production

International crude oil and NGLs production for the first quarter of 2024 averaged 24,823 bbl/d, a decrease of 9% from 27,331 bbl/d for the first quarter of 2023, and a decrease of 4% from 25,829 bbl/d for the fourth quarter of 2023. The decrease in International crude oil and NGLs production for the first quarter of 2024 from the comparable periods in 2023 primarily reflected natural field declines, combined with the impact of maintenance activities in all periods presented.

International Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when control of the product passes to the customer and delivery has taken place. Revenue has not been recognized in the International segments on crude oil volumes held in various storage facilities or FPSOs, as follows:

(bbl)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
International	**833,654**	515,543	1,912,388

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Crude oil and NGLs ($/bbl) (1)			
Realized price (2)	**$ 70.01**	$ 69.39	$ 58.85
Transportation (2)	**4.63**	3.83	4.52
Realized price, net of transportation (2)	**65.38**	65.56	54.33
Royalties (3)	**12.09**	11.38	10.09
Production expense (4)	**16.66**	15.05	16.93
Netback (2)	**$ 36.63**	$ 39.13	$ 27.31
Natural gas ($/Mcf) (1)			
Realized price (5)	**$ 2.55**	$ 2.80	$ 4.27
Transportation (6)	**0.64**	0.54	0.55
Realized price, net of transportation	**1.91**	2.26	3.72
Royalties (3)	**0.10**	0.09	0.28
Production expense (4)	**1.30**	1.13	1.47
Netback	**$ 0.51**	$ 1.04	$ 1.97
Barrels of oil equivalent ($/BOE) (1)			
Realized price (2)	**$ 47.60**	$ 48.41	$ 44.98
Transportation (2)	**4.31**	3.61	4.03
Realized price, net of transportation (2)	**43.29**	44.80	40.95
Royalties (3)	**7.39**	7.05	6.56
Production expense (4)	**13.03**	11.75	13.51
Netback (2)	**$ 22.87**	$ 26.00	$ 20.88

(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 royalties divided by respective sales volumes.

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

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

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

REALIZED PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Crude oil and NGLs ($/bbl) [1]			
North America [2]	**$ 68.14**	$ 66.69	$ 57.99
International average [3]	**$ 112.94**	$ 112.22	$ 98.60
North Sea [3]	**$ 113.75**	$ 118.50	$ —
Offshore Africa [3]	**$ 111.59**	$ 107.88	$ 98.60
Crude oil and NGLs average [2]	**$ 70.01**	$ 69.39	$ 58.85
Natural gas ($/Mcf) [1] [3]			
North America	**$ 2.50**	$ 2.75	$ 4.22
International average	**$ 12.13**	$ 12.15	$ 13.76
North Sea	**$ 11.48**	$ 9.66	$ 11.81
Offshore Africa	**$ 12.22**	$ 12.51	$ 14.28
Natural gas average	**$ 2.55**	$ 2.80	$ 4.27
Average ($/BOE) [1] [2]	**$ 47.60**	$ 48.41	$ 44.98

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

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

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

North America

North America realized crude oil and NGLs prices averaged $68.14 per bbl for the first quarter of 2024, an increase of 18% from $57.99 per bbl for the first quarter of 2023, and comparable with $66.69 per bbl for the fourth quarter of 2023. The increase for the first quarter of 2024 from the first quarter of 2023 primarily reflected the narrowing of the WCS Heavy Differential, combined with higher sales volumes to the US Gulf Coast, subject to higher realized pricing. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2024 contributed approximately 233,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 41% to average $2.50 per Mcf for the first quarter of 2024 from $4.22 per Mcf for the first quarter of 2023, and decreased 9% from $2.75 per Mcf for the fourth quarter of 2023. The decrease in North America realized natural gas prices for first quarter of 2024 from the comparable periods in 2023 primarily reflected lower AECO benchmark and export pricing.

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

	Three Months Ended		
(Quarterly average)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Wellhead Price [1]			
Light and medium crude oil and NGLs ($/bbl)	**$ 66.68**	$ 69.42	$ 73.26
Pelican Lake heavy crude oil ($/bbl)	**$ 74.69**	$ 73.47	$ 67.57
Primary heavy crude oil ($/bbl)	**$ 74.37**	$ 72.90	$ 60.31
Bitumen (thermal oil) ($/bbl)	**$ 65.83**	$ 62.64	$ 48.60
Natural gas ($/Mcf)	**$ 2.50**	$ 2.75	$ 4.22

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

International

International realized crude oil and NGLs prices increased 15% to average $112.94 per bbl for the first quarter of 2024 from $98.60 per bbl for the first quarter of 2023, and were comparable with $112.22 per bbl for the fourth quarter of 2023. 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 crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil and NGLs prices for the first quarter of 2024 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 12.52**	$ 11.72	$ 10.10
International average	**$ 2.29**	$ 5.83	$ 9.46
North Sea	**$ 0.24**	$ 0.24	$ —
Offshore Africa	**$ 5.72**	$ 10.58	$ 9.46
Crude oil and NGLs average	**$ 12.09**	$ 11.38	$ 10.09
Natural gas ($/Mcf) [1]			
North America	**$ 0.10**	$ 0.09	$ 0.27
Offshore Africa	**$ 0.56**	$ 0.59	$ 0.69
Natural gas average	**$ 0.10**	$ 0.09	$ 0.28
Average ($/BOE) [1]	**$ 7.39**	$ 7.05	$ 6.56

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

North America

North America crude oil and NGLs and natural gas royalties for the first quarter of 2024 and the comparable periods reflected movements in benchmark commodity prices, fluctuations in the WCS Heavy Differential and the impact of sliding scale royalty rates.

Crude oil and NGLs royalty rates [1] averaged approximately 18% of product sales for the first quarter of 2024 compared with 17% for the first quarter of 2023, and 18% for the fourth quarter of 2023 reflecting prevailing benchmark pricing and fluctuations in the WCS differential.

Natural gas royalty rates averaged approximately 4% of product sales for the first quarter of 2024 compared with 6% for the first quarter of 2023, and 3% for the fourth quarter of 2023. The fluctuations in royalty rates for the first quarter of 2024 from the comparable periods in 2023 primarily reflected fluctuating benchmark prices.

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 5% for the first quarter of 2024 compared with 9% of product sales for the first quarter of 2023, and 9% for the fourth quarter of 2023. Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

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

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2024	Dec 31 2023	Mar 31 2023
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 14.72**	$ 12.56	$ 16.82
International average	**$ 61.32**	$ 54.95	$ 21.90
North Sea	**$ 85.58**	$ 92.28	$ —
Offshore Africa	**$ 20.70**	$ 23.25	$ 21.90
Crude oil and NGLs average	**$ 16.66**	$ 15.05	$ 16.93
Natural gas ($/Mcf) [1]			
North America	**$ 1.27**	$ 1.09	$ 1.43
International average	**$ 5.71**	$ 8.76	$ 8.08
North Sea	**$ 8.66**	$ 9.52	$ 10.80
Offshore Africa	**$ 5.33**	$ 8.65	$ 7.35
Natural gas average	**$ 1.30**	$ 1.13	$ 1.47
Average ($/BOE) [1]	**$ 13.03**	$ 11.75	$ 13.51

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

North America

North America crude oil and NGLs production expense for the first quarter of 2024 of $14.72 per bbl decreased 12% from $16.82 per bbl for the first quarter of 2023, and increased 17% from $12.56 per bbl for the fourth quarter of 2023. The decrease in crude oil and NGLs production expense per bbl for the first quarter of 2024 from the first quarter of 2023 primarily reflected lower energy costs and higher production volumes. The increase in crude oil and NGLs production expense per bbl for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected higher energy and service costs, combined with lower production volumes.

North America natural gas production expense for the first quarter of 2024 averaged $1.27 per Mcf, a decrease of 11% from $1.43 per Mcf for the first quarter of 2023, and an increase of 17% from $1.09 per Mcf for the fourth quarter of 2023. The decrease in natural gas production expense per Mcf for the first quarter of 2024 from the first quarter of 2023 primarily reflected lower energy and service costs. The increase for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected higher service costs and the impact of seasonality.

International

International crude oil and NGLs production expense for the first quarter of 2024 of $61.32 per bbl increased from $21.90 per bbl for the first quarter of 2023 as there were no crude oil liftings in the North Sea during the first quarter of 2023. Production expense increased 12% from $54.95 per bbl for the fourth quarter of 2023, primarily reflecting the timing of liftings from various fields. Fluctuations in production expense per bbl also included the impact of foreign exchange.

ADJUSTED DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)	Three Months Ended **Mar 31 2024**	Dec 31 2023	Mar 31 2023
North America	**$ 941**	$ 971	$ 890
North Sea	**17**	466	1
Offshore Africa	**47**	66	35
Depletion, depreciation and amortization	**$ 1,005**	$ 1,503	$ 926
Less: Recoverability charge (1)	**—**	436	—
Adjusted depletion, depreciation and amortization (2)	**$ 1,005**	$ 1,067	$ 926
$/BOE (3)	**$ 12.64**	$ 12.46	$ 12.14

(1) As at December 31, 2023, as a result of revised project scope and the current cost environment, the Company recognized a recoverability charge of $436 million in depletion, depreciation and amortization expense related to an increase in its estimate of future abandonment costs for the Ninian field in the North Sea.

(2) This is a non-GAAP 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 applicable, as an indication of the Company's performance.

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

Adjusted depletion, depreciation and amortization expense for the first quarter of 2024 averaged $12.64 per BOE, an increase of 4% from $12.14 per BOE for the first quarter of 2023, and comparable with $12.46 per BOE for the fourth quarter of 2023. The increase in adjusted depletion, depreciation and amortization expense for the first quarter of 2024 from the first quarter of 2023 primarily reflected the impact of changes in North America depletion rates due to changes in reserve estimates at December 31, 2023.

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 **Mar 31 2024**	Dec 31 2023	Mar 31 2023
North America	**$ 58**	$ 58	$ 59
North Sea	**16**	12	11
Offshore Africa	**2**	2	2
Asset retirement obligation accretion	**$ 76**	$ 72	$ 72
$/BOE (1)	**$ 0.95**	$ 0.84	$ 0.94

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for the first quarter of 2024 averaged $0.95 per BOE, comparable with $0.94 per BOE for the first quarter of 2023, and an increase of 13% from $0.84 per BOE for the fourth quarter of 2023. The increase in asset retirement obligation accretion expense per BOE for the first quarter of 2024 from the fourth quarter of 2023 reflected the increase in the Company's estimate for future abandonment costs for the Ninian field in the North Sea at December 31, 2023, combined with lower sales volumes.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable, and efficient operations leveraging its technical expertise across the Horizon and AOSP sites with SCO production averaging 445,209 bbl/d in the first quarter of 2024, primarily reflecting planned and unplanned maintenance in the first quarter of 2024, including the advancement of turnaround activities at Scotford from April into March.

The Company targets strong performance in the Oil Sands Mining and Upgrading segment for the remainder of 2024, including the targeted reduction in the duration of the planned turnaround at Horizon commencing in May 2024 and the optimization of commissioning activities for the reliability enhancement project.

The Company incurred production expense of $1,026 million for the first quarter of 2024, comparable with $1,042 million for the first quarter of 2023, and an increase of 8% from $947 million for the fourth quarter of 2023. The increase in production expense for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected increased maintenance costs in the first quarter of 2024. The Company continues to focus on cost control and driving efficiencies across the entire asset base.

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

	Three Months Ended		
($/bbl)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Realized SCO sales price [(1)]	**$ 88.84**	$ 98.73	$ 96.07
Bitumen value for royalty purposes [(2)]	**$ 63.51**	$ 61.73	$ 47.73
Bitumen royalties [(3)]	**$ 14.28**	$ 11.57	$ 10.04
Transportation [(1)]	**$ 1.67**	$ 1.85	$ 1.52

(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.

The realized SCO sales price averaged $88.84 per bbl for the first quarter of 2024, a decrease of 8% from $96.07 per bbl for the first quarter of 2023, and a decrease of 10% from $98.73 per bbl for the fourth quarter of 2023. The decrease in realized SCO sales price for the first quarter of 2024 from the comparable periods in 2023 primarily reflected the weakening in the SCO differential from WTI due to strong production levels and egress constraints in the WCSB.

The increase in bitumen royalties per bbl for the first quarter of 2024 from the first quarter of 2023 primarily reflected higher prevailing bitumen pricing for royalty purposes, combined with the impact of sliding scale royalty rates. The increase for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected the impact of sliding scale royalty rates.

Transportation expense averaged $1.67 per bbl for the first quarter of 2024, an increase of 10% from $1.52 per bbl for the first quarter of 2023, and a decrease of 10% from $1.85 per bbl for the fourth quarter of 2023. The increase in transportation expense per bbl for first quarter of 2024 from the first quarter of 2023 primarily reflected higher sales volumes to the US Gulf Coast in the first quarter of 2024. The decrease for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected lower sales volumes to the US Gulf Coast.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Production expense, excluding natural gas costs	**$ 976**	$ 904	$ 971
Natural gas costs	**50**	43	71
Production expense	**$ 1,026**	$ 947	$ 1,042

($/bbl)	Three Months Ended **Mar 31 2024**	Dec 31 2023	Mar 31 2023
Production expense, excluding natural gas costs (1)	**$ 23.64**	$ 20.00	$ 23.35
Natural gas costs (2)	**1.21**	0.96	1.71
Production expense (3)	**$ 24.85**	$ 20.96	$ 25.06
Sales volumes (bbl/d)	**453,794**	491,339	462,021

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

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

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

Production expense for the first quarter of 2024 averaged $24.85 per bbl, comparable with $25.06 per bbl for the first quarter of 2023, and an increase of 19% from $20.96 per bbl for the fourth quarter of 2023. The increase in production expense per bbl for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected higher maintenance costs in the first quarter of 2024, combined with lower production volumes, due to planned and unplanned maintenance in the first quarter of 2024, including the advancement of turnaround activities at Scotford from April into March.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended **Mar 31 2024**	Dec 31 2023	Mar 31 2023
Depletion, depreciation and amortization	**$ 524**	$ 554	$ 488
$/bbl (1)	**$ 12.70**	$ 12.25	$ 11.74

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

Depletion, depreciation and amortization expense for the first quarter of 2024 of $12.70 per bbl increased 8% from $11.74 per bbl for the first quarter of 2023, and increased 4% from $12.25 per bbl for the fourth quarter of 2023. The increase in depletion, depreciation and amortization expense per bbl for the first quarter of 2024 from the comparable periods in 2023 primarily reflected the impact of a higher depletable base due to asset additions, including those assets subject to straight-line depreciation. The increase for the first quarter of 2024 from the fourth quarter of 2023 also reflected lower sales volumes in the first quarter of 2024.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended **Mar 31 2024**	Dec 31 2023	Mar 31 2023
Asset retirement obligation accretion	**$ 21**	$ 19	$ 20
$/bbl (1)	**$ 0.51**	$ 0.43	$ 0.47

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for the first quarter of 2024 of $0.51 per bbl increased 9% from $0.47 per bbl for the first quarter of 2023, and increased 19% from $0.43 per bbl for the fourth quarter of 2023. The increase in asset retirement obligation accretion expense per bbl for the first quarter of 2024 from the comparable periods in 2023 primarily reflected the impact of changes in cost and timing estimates, partially offset by discount rate estimate revisions at December 31, 2023. The increase in asset retirement obligation accretion expense per bbl for the first quarter of 2024 from the fourth quarter of 2023 also reflected the impact of lower sales volumes in the first quarter of 2024.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended **Mar 31 2024**	Dec 31 2023	Mar 31 2023
Product sales			
Midstream activities	**$ 20**	$ 20	$ 21
NWRP, refined product sales and other	**214**	236	250
Segmented revenue	**234**	256	271
Less:			
NWRP, refining toll	**74**	82	70
Midstream activities	**5**	7	8
Production expense	**79**	89	78
NWRP, transportation and feedstock costs	**158**	166	153
Depreciation	**4**	4	4
Segmented (loss) earnings	**$ (7)**	$ (3)	$ 36

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 50,000 bbl/d bitumen upgrader and refinery that processes approximately 12,500 bbl/d (25% toll payer) of bitumen feedstock for the Company and 37,500 bbl/d (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), 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 first quarter of 2024, production of ultra-low sulphur diesel and other refined products averaged 78,569 BOE/d (19,642 BOE/d to the Company), (three months ended December 31, 2023 – 83,294, BOE/d; 20,824 BOE/d to the Company; three months ended March 31, 2023 – 85,376 BOE/d; 21,344 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at March 31, 2024, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $551 million (December 31, 2023 – $555 million). For the three months ended March 31, 2024, the Company's recovery of its share of unrecognized equity losses was $4 million (three months ended March 31, 2023 – unrecognized equity loss of $16 million).

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended **Mar 31 2024**	Dec 31 2023	Mar 31 2023
Administration expense	**$ 126**	$ 119	$ 106
$/BOE (1)	**$ 1.04**	$ 0.91	$ 0.90
Sales volumes (BOE/d) (2)	**1,327,762**	1,422,198	1,309,942

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

(2) Total Company sales volumes.

Administration expense for the first quarter of 2024 of $1.04 per BOE increased 16% from $0.90 per BOE for the first quarter of 2023, and increased 14% from $0.91 per BOE for the fourth quarter of 2023. The increase in administration expense per BOE for the first quarter of 2024 from the first quarter of 2023 primarily reflected higher personnel and corporate costs. The increase in administration expense per BOE for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected higher personnel costs combined with lower sales volumes, partially offset by higher overhead recoveries.

SHARE-BASED COMPENSATION

	Three Months Ended		
($ millions)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Stock-based compensation expense	**$ 294**	$ 57	$ 66

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, and by individual employee performance and the extent to which certain other performance measures are met.

The Company recognized $294 million of share-based compensation expense for the three months ended March 31, 2024, primarily as a result of 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, the impact of vested stock options exercised or surrendered during the period, and changes in the Company's share price.

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended		
($ millions, except effective interest rate)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Interest and other financing expense	**$ 138**	$ 117	$ 154
Less: Interest income and other (1)	**22**	53	9
Interest expense on long-term debt and lease liabilities (1)	**$ 160**	$ 170	$ 163
Average current and long-term debt (2)	**$ 11,595**	$ 12,350	$ 12,343
Average lease liabilities (2)	**1,542**	1,484	1,516
Average long-term debt and lease liabilities (2)	**$ 13,137**	$ 13,834	$ 13,859
Average effective interest rate (3) (4)	**4.8%**	4.8%	4.6%
Interest and other financing expense per $/BOE (5)	**$ 1.15**	$ 0.90	$ 1.30
Sales volumes (BOE/d) (6)	**1,327,762**	1,422,198	1,309,942

(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 per BOE for the first quarter of 2024 decreased 12% to $1.15 per BOE from $1.30 per BOE for the first quarter of 2023, and increased 28% from $0.90 per BOE for the fourth quarter of 2023. The decrease in interest and other financing expense per BOE for the first quarter of 2024 from the first quarter of 2023 reflected lower average debt levels in 2024, combined with higher interest income in the first quarter of 2024. The increase in interest and other financing expense per BOE for the first quarter of 2024 from the fourth quarter of 2023 primarily reflected the impact of accrued interest on the PRT recovery in the fourth quarter of 2023, and lower sales volumes in the first quarter of 2024.

The Company's average effective interest rate for the first quarter of 2024 of 4.8% increased from 4.6% for the first quarter of 2023, primarily reflecting higher prevailing interest rates on floating rate long-term debt held during the first quarter of 2024.

RISK MANAGEMENT ACTIVITIES

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

($ millions)	Three Months Ended **Mar 31 2024**	Dec 31 2023	Mar 31 2023
Foreign currency contracts	**$ 26**	$ (15)	$ (2)
Natural gas financial instruments (1) (2)	**(1)**	(2)	3
Net realized loss (gain)	**25**	(17)	1
Foreign currency contracts	**9**	(16)	3
Natural gas financial instruments (1) (2)	**4**	9	17
Net unrealized loss (gain)	**13**	(7)	20
Net loss (gain)	**$ 38**	$ (24)	$ 21

(1) Certain commodity financial instruments were assumed in the acquisition of Storm Resources Ltd. and Painted Pony Energy Ltd. in the fourth quarter of 2021 and 2020, respectively.

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

During the first quarter of 2024 net realized risk management losses were related to the settlement of foreign currency contracts. The Company recorded a net unrealized loss of $13 million ($12 million after tax of $1 million) on its risk management activities for the three months ended March 31, 2024 (three months ended December 31, 2023 – unrealized gain of $7 million, ($9 million after tax of $2 million); three months ended March 31, 2023 – unrealized loss of $20 million, ($16 million after tax of $4 million)).

Further details related to outstanding derivative financial instruments as at March 31, 2024 are disclosed in note 15 to the financial statements.

FOREIGN EXCHANGE

($ millions)	Three Months Ended **Mar 31 2024**	Dec 31 2023	Mar 31 2023
Net realized (gain) loss	**$ (19)**	$ 11	$ (11)
Net unrealized loss (gain)	**269**	(276)	(3)
Net loss (gain) (1)	**$ 250**	$ (265)	$ (14)

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The net realized foreign exchange gain for the first quarter of 2024 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange loss for the first quarter of 2024 was primarily related to the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at March 31, 2024 was US$0.7390 (December 31, 2023 – US$0.7573, March 31, 2023 – US$0.7392).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended **Mar 31 2024**	Dec 31 2023	Mar 31 2023
North America [1]	**$ 412**	$ 487	$ 480
North Sea	**(5)**	3	6
Offshore Africa	**5**	20	10
Current PRT – North Sea	**(14)**	(13)	(40)
Other taxes	**3**	8	3
Current income tax	**401**	505	459
Deferred corporate income tax	**14**	64	23
Deferred PRT – North Sea	**6**	(238)	7
Deferred income tax	**20**	(174)	30
Income tax	**$ 421**	$ 331	$ 489
Earnings before taxes	**$ 1,408**	$ 2,958	$ 2,288
Effective tax rate on net earnings [2]	**30%**	11%	21%

($ millions, except effective tax rates)	Three Months Ended **Mar 31 2024**	Dec 31 2023	Mar 31 2023
Income tax	**$ 421**	$ 331	$ 489
Tax effect on non-operating items [3]	**14**	331	8
Current PRT – North Sea	**14**	13	40
Deferred PRT – North Sea	**(6)**	33	(7)
Other taxes	**(3)**	(8)	(3)
Effective tax on adjusted net earnings	**$ 440**	$ 700	$ 527
Adjusted net earnings from operations [4]	**$ 1,474**	$ 2,546	$ 1,881
Adjusted net earnings from operations, before taxes	**$ 1,914**	$ 3,246	$ 2,408
Effective tax rate on adjusted net earnings from operations [5] [6]	**23%**	22%	22%

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

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

(3) Includes the net income tax effect on PSUs, certain stock options, unrealized risk management, and deferred PRT and income tax recoveries related to the recoverability charge recognized in 2023.

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

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

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

The effective tax rate on net earnings and adjusted net earnings from operations for the first quarter of 2024 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 first quarter of 2024 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)

	Three Months Ended		
($ millions)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Exploration and Production			
Exploration and Evaluation Assets			
Net expenditures	**$ 69**	$ 12	$ 28
Total Exploration and Evaluation Assets	**69**	12	28
Property, Plant and Equipment			
Net property dispositions	**(3)**	(1)	—
Well drilling, completion and equipping	**413**	274	510
Production and related facilities	**255**	251	361
Other	**12**	13	11
Total Property, Plant and Equipment	**677**	537	882
Total Exploration and Production	**746**	549	910
Oil Sands Mining and Upgrading			
Project costs	**62**	78	52
Sustaining capital	**281**	320	261
Turnaround costs	**11**	17	22
Net property dispositions	**(2)**	(1)	—
Other	**1**	1	1
Total Oil Sands Mining and Upgrading	**353**	415	336
Midstream and Refining	**4**	4	3
Head office	**10**	7	8
Net capital expenditures	**$ 1,113**	$ 975	$ 1,257
Abandonment expenditures	**$ 162**	$ 149	$ 137
By Segment			
North America	**$ 701**	$ 479	$ 884
North Sea	**4**	11	3
Offshore Africa	**41**	59	23
Oil Sands Mining and Upgrading	**353**	415	336
Midstream and Refining	**4**	4	3
Head office	**10**	7	8
Net capital expenditures	**$ 1,113**	$ 975	$ 1,257

(1) Net capital expenditures exclude the impact of lease assets, fair value and revaluation adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.

(2) Non-GAAP Financial Measure. The composition of this measure has been updated for all periods presented. 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 $1,113 million for the first quarter of 2024, compared with $1,257 million for the first quarter of 2023 and $975 million for the fourth quarter of 2023.

In addition, the Company reported abandonment expenditures of $162 million for the first quarter of 2024, compared with $137 million for the first quarter of 2023, and $149 million for the fourth quarter of 2023.

2024 Capital Budget

On December 14, 2023, the Company announced its 2024 capital budget targeted at approximately $5,420 million, and targeting to provide near-term production growth in 2024 and mid- and long-term production and capacity growth in 2025 and beyond. Production for 2024 is targeted between 1,330,000 BOE/d and 1,380,000 BOE/d. In addition, the Company targets $635 million in abandonment expenditures for 2024.

The 2024 capital budget constitutes forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Drilling Activity (1) (2)

	Three Months Ended		
(number of net wells)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Net successful crude oil wells (3)	**61**	42	83
Net successful natural gas wells	**16**	9	21
Dry wells	**—**	—	2
Total	**77**	51	106
Success rate	**100%**	100%	98%

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

(2) Excludes stratigraphic and service wells.

(3) Includes bitumen wells.

North America

During the first quarter of 2024, the Company drilled 16 net natural gas wells, 26 net primary heavy crude oil wells, 23 net bitumen (thermal oil) wells and 12 net light crude oil wells.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Adjusted working capital (1)	**$ 774**	$ 712	$ (307)
Long-term debt, net (2)	**$ 10,273**	$ 9,922	$ 11,932
Shareholders' equity	**$ 39,508**	$ 39,832	$ 38,585
Debt to book capitalization (2)	**20.6%**	19.9%	23.6 %
After-tax return on average capital employed (3)	**15.6%**	17.2%	19.7 %

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

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

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

As at March 31, 2024, 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, 2023. 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:
  - Borrowings under the Company's revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, 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 March 31, 2024, the Company repaid US$500 million of 3.80% US dollar debt securities due April 15, 2024.
  - 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 March 31, 2024, the Company had undrawn revolving bank credit facilities of $5,450 million. Including cash and cash equivalents and short-term investments, the Company had approximately $6,817 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. At March 31, 2024, the Company had no commercial paper 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 $10,273 million as at March 31, 2024, resulting in a debt to book capitalization ratio of 20.6% (December 31, 2023 – 19.9%); this ratio was below 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 remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt as at March 31, 2024 are discussed in note 8 to the financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at March 31, 2024, the Company was in compliance with this covenant.

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 put options is in addition to the above parameters.

As at March 31, 2024, 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)]	$	1,809	$	812	$	2,357	$	6,119
Other long-term liabilities [(2)]	$	291	$	198	$	425	$	627
Interest and other financing expense [(3)]	$	579	$	504	$	1,294	$	3,312

(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, $285 million; one to less than two years, $198 million; two to less than five years, $425 million; and thereafter, $627 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 March 31, 2024.

Share Capital

As at March 31, 2024, there were 1,069,988,000 common shares outstanding (December 31, 2023 – 1,072,408,000 common shares) and 28,286,000 stock options outstanding (December 31, 2023 – 26,205,000). As at April 30, 2024, the Company had 1,067,354,000 common shares outstanding and 27,365,000 stock options outstanding.

On February 28, 2024, the Board of Directors approved a 5% increase in the quarterly dividend to $1.05 per common share, beginning with the dividend paid on April 5, 2024.

On November 1, 2023, the Board of Directors approved an 11% increase in the quarterly dividend to $1.00 per common share. On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.90 per common share.

On March 8, 2024, 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, up to 90,231,429 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2024 and ending March 12, 2025.

For the three months ended March 31, 2024, the Company purchased 6,675,000 common shares at a weighted average price of $90.78 per common share for a total cost of $606 million. Retained earnings were reduced by $538 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2024, up to and including April 30, 2024, the Company purchased 2,750,000 common shares at a weighted average price of $107.16 per common share for a total cost of $295 million.

Share Split

On February 28, 2024, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval and the Company having obtained all regulatory approvals, including TSX approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 2, 2024.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at March 31, 2024:

($ millions)		Remaining 2024		2025		2026		2027		2028		Thereafter
Product transportation and processing [1]	$	1,244	$	1,675	$	1,530	$	1,462	$	1,347	$	13,621
North West Redwater Partnership service toll [2]	$	117	$	156	$	138	$	124	$	128	$	4,933
Offshore vessels and equipment	$	28	$	35	$	—	$	—	$	—	$	—
Field equipment and power	$	38	$	25	$	23	$	22	$	22	$	193
Other	$	123	$	111	$	111	$	25	$	26	$	355

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

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $2,922 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, 2023.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended March 31, 2024 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting. Due to inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

NON-GAAP AND OTHER FINANCIAL MEASURES

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

Adjusted Net Earnings from Operations

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

	Three Months Ended		
($ millions)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Net earnings	**$ 987**	$ 2,627	$ 1,799
Share-based compensation, net of tax (1)	**281**	51	62
Unrealized risk management loss (gain), net of tax (2)	**12**	(9)	16
Unrealized foreign exchange loss (gain), net of tax (3)	**269**	(276)	(3)
(Gain) loss from investments, net of tax (4)	**(75)**	40	7
Recoverability charge, net of tax (5)	**—**	113	—
Non-operating items, net of tax	**487**	(81)	82
Adjusted net earnings from operations	**$ 1,474**	$ 2,546	$ 1,881

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings. Pre-tax share-based compensation for the three months ended March 31, 2024 was an expense of $294 million (three months ended December 31, 2023 – $57 million expense, three months ended March 31, 2023 – $66 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 crude oil, natural gas and foreign exchange. Pre-tax unrealized risk management loss for the three months ended March 31, 2024 was $13 million (three months ended December 31, 2023 – $7 million gain, three months ended March 31, 2023 – $20 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) The Company's investments have been accounted for at fair value through profit and loss and are measured each period with gains and losses recognized in net earnings. There is zero net tax impact on these gains and losses from investments.

(5) The Company recognized a pre-tax recoverability charge of $436 million in depletion, depreciation and amortization expense in 2023 related to revised project scope and the current cost environment for planned decommissioning and abandonment activities at the Ninian field in the North Sea. These costs are considered to be non-operating in nature.

Adjusted Funds Flow

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

	Three Months Ended		
($ millions)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Cash flows from operating activities	**$ 2,868**	$ 4,815	$ 1,295
Net change in non-cash working capital	**15**	(562)	1,908
Abandonment expenditures	**162**	149	137
Movements in other long-term assets (1)	**93**	17	89
Adjusted funds flow	**$ 3,138**	$ 4,419	$ 3,429

(1) Includes the unamortized cost of the share bonus program, the accrued interest on the deferred PRT recovery, and prepaid cost of service tolls.

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

Adjusted net earnings from operations and adjusted funds flow, per common share (basic and diluted), are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 14 to the financial statements. These non-GAAP measures, disclosed on a per share basis, enable a comparison to the per share amounts disclosed in the Company's financial statements prepared in accordance with IFRS.

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 non-GAAP financial measures: realized price and transportation, reconciled below to their respective line item in note 17 to the financial statements.

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

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

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

($ millions, except bbl/d and $/bbl)	Three Months Ended **Mar 31 2024**	 Dec 31 2023	 Mar 31 2023
Crude oil and NGLs (bbl/d)			
North America	**494,621**	526,350	481,045
International			
North Sea	**13,468**	15,032	—
Offshore Africa	**8,046**	17,705	10,393
Total International	**21,514**	32,737	10,393
Total sales volumes	**516,135**	559,087	491,438
Crude oil and NGLs sales (1)	**$ 4,505**	$ 4,790	$ 3,841
Less: Blending and feedstock costs (2)	**1,217**	1,222	1,238
Realized crude oil and NGLs sales	**$ 3,288**	$ 3,568	$ 2,603
Realized price ($/bbl)	**$ 70.01**	$ 69.39	$ 58.85

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

(2) Blending and feedstock costs are a component of transportation, blending and feedstock expense as reconciled below in the "Transportation – Exploration and Production" section.

($ millions, except BOE/d and $/BOE)	Three Months Ended **Mar 31 2024**	 Dec 31 2023	 Mar 31 2023
Barrels of oil equivalent (BOE/d)			
North America	**850,336**	895,996	835,542
International			
North Sea	**13,709**	15,296	419
Offshore Africa	**9,924**	19,567	11,961
Total International	**23,633**	34,863	12,380
Total sales volumes	**873,969**	930,859	847,922
Barrels of oil equivalent sales (1)	**$ 5,004**	$ 5,365	$ 4,663
Less: Blending and feedstock costs (2)	**1,217**	1,222	1,238
Less: Sulphur expense (income)	**1**	(2)	(8)
Realized barrels of oil equivalent sales	**$ 3,786**	$ 4,145	$ 3,433
Realized price ($/BOE)	**$ 47.60**	$ 48.41	$ 44.98

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

(2) Blending and feedstock costs are a component of transportation, blending and feedstock expense as reconciled below in the "Transportation – Exploration and Production" section.

Transportation – Exploration and Production

Transportation ($/BOE, $/bbl and $/Mcf) is a non-GAAP ratio calculated as transportation (a non-GAAP financial measure) divided by the respective sales volumes. The Company calculates transportation to demonstrate its cost to deliver products to the market excluding the impact of blending costs. A reconciliation for Exploration and Production transportation and the calculations for transportation on a per unit basis are presented below.

	Three Months Ended		
($ millions, except $ per unit amounts)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Transportation, blending and feedstock [1]	**$ 1,560**	$ 1,531	$ 1,546
Less: Blending and feedstock costs	**1,217**	1,222	1,238
Transportation	**$ 343**	$ 309	$ 308
Transportation ($/BOE)	**$ 4.31**	$ 3.61	$ 4.03
Amounts attributed to crude oil and NGLs	**$ 217**	$ 197	$ 200
Transportation ($/bbl)	**$ 4.63**	$ 3.83	$ 4.52
Amounts attributed to natural gas	**$ 126**	$ 112	$ 108
Transportation ($/Mcf)	**$ 0.64**	$ 0.54	$ 0.55

(1) Transportation, blending and feedstock in note 17 to the financial statements.

North America – Realized Product Prices and Royalties

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

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

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

	Three Months Ended		
($ millions, except $/bbl and royalty rates)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Crude oil and NGLs sales [1]	**$ 4,284**	$ 4,451	$ 3,749
Less: Blending and feedstock costs [2]	**1,217**	1,222	1,238
Realized crude oil and NGLs sales	**$ 3,067**	$ 3,229	$ 2,511
Realized crude oil and NGLs prices ($/bbl)	**$ 68.14**	$ 66.69	$ 57.99
Crude oil and NGLs royalties [3]	**$ 563**	$ 567	$ 437
Crude oil and NGLs royalty rates	**18%**	18%	17%

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

(2) Blending and feedstock costs are a component of transportation, blending and feedstock expense as reconciled above in the "Transportation – Exploration and Production" section.

(3) Item is a component of royalties in note 17 to the financial statements.

Realized Product Prices and Transportation – Oil Sands Mining and Upgrading

Realized SCO sales price ($/bbl) is a non-GAAP ratio calculated as realized SCO sales (non-GAAP financial measure) excluding the impact of blending and feedstock costs, divided by SCO sales volumes. 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.

Transportation ($/bbl) is a non-GAAP ratio calculated as transportation (a non-GAAP financial measure) divided by SCO sales volumes. The Company calculates transportation to demonstrate its cost to deliver product to the market excluding the impact of blending and feedstock costs.

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

	Three Months Ended		
($ millions, except for bbl/d and $/bbl)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
SCO sales volumes (bbl/d)	**453,794**	491,339	462,021
Crude oil and NGLs sales (1)	**$ 4,168**	$ 5,042	$ 4,482
Less: Blending and feedstock costs	**499**	579	487
Realized SCO sales	**$ 3,669**	$ 4,463	$ 3,995
Realized SCO sales price ($/bbl)	**$ 88.84**	$ 98.73	$ 96.07
Transportation, blending and feedstock (2)	**$ 568**	$ 663	$ 550
Less: Blending and feedstock costs	**499**	579	487
Transportation	**$ 69**	$ 84	$ 63
Transportation ($/bbl)	**$ 1.67**	$ 1.85	$ 1.52

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

(2) Transportation, blending and feedstock in note 17 to the financial statements.

Change in Composition of Non-GAAP Financial Measure

During the fourth quarter of 2023, the Company revised the composition of its Net Capital Expenditures non-GAAP financial measure to exclude expenditures related to the Company's abandonment program. The revision was made during Management's assessment of its annual capital budgeting process, and will provide users a better representation of the Company's performance and the composition of its capital budget. The composition of this measure has been updated for all periods presented.

Net Capital Expenditures

Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, and cash flows from investing activities not included in the Company's capital budget. The Company includes acquisition and disposition capital in net capital expenditures. The Company considers net capital expenditures a key measure in evaluating its performance, as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. A reconciliation of net capital expenditures is presented below.

	Three Months Ended		
($ millions)	**Mar 31 2024**	Dec 31 2023	Mar 31 2023
Cash flows used in investing activities	**$ 1,392**	$ 946	$ 1,153
Net change in non-cash working capital	**(279)**	29	104
Net capital expenditures	**1,113**	975	1,257
Abandonment expenditures	**162**	149	137
Capital and abandonment expenditures	**$ 1,275**	$ 1,124	$ 1,394

Liquidity

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

($ millions)		**Mar 31 2024**		Dec 31 2023		Mar 31 2023
Undrawn bank credit facilities	**$**	**5,450**	$	5,450	$	5,520
Cash and cash equivalents		**767**		877		92
Investments		**600**		525		484
Liquidity	**$**	**6,817**	$	6,852	$	6,096

Long-term Debt, net

Long-term debt, net, is a capital management measure that represents long-term debt, including the current portion of long-term debt, less cash and cash equivalents, as disclosed in note 13 to the financial statements. A reconciliation of long-term debt, net is presented below.

($ millions)		**Mar 31 2024**		Dec 31 2023		Mar 31 2023
Long-term debt	**$**	**11,040**	$	10,799	$	12,024
Less: cash and cash equivalents		**767**		877		92
Long-term debt, net	**$**	**10,273**	$	9,922	$	11,932

Debt to Book Capitalization

Debt to book capitalization is a capital management measure intended to enable financial statement users to evaluate the Company's capital structure, as disclosed in note 13 to the financial statements.

After-Tax Return on Average Capital Employed

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

($ millions, except ratios)		**Mar 31 2024**		Dec 31 2023		Mar 31 2023
Interest adjusted after-tax return:						
Net earnings, 12 months trailing	**$**	**7,421**	$	8,233	$	9,635
Interest and other financing expense, net of tax, 12 months trailing (1)		**477**		490		417
Interest adjusted after-tax return	**$**	**7,898**	$	8,723	$	10,052
12 months average current portion long-term debt (2)	**$**	**1,541**	$	1,259	$	1,357
12 months average long-term debt (2)		**9,992**		10,354		11,228
12 months average common shareholders' equity (2)		**39,240**		38,974		38,544
12 months average capital employed	**$**	**50,773**	$	50,587	$	51,129
After-tax return on average capital employed		**15.6%**		17.2%		19.7%

(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	**Mar 31 2024**	Dec 31 2023
ASSETS			
Current assets			
Cash and cash equivalents		**$ 767**	$ 877
Accounts receivable		**3,408**	3,189
Inventory		**2,303**	2,034
Prepaids and other		**303**	471
Investments	6	**600**	525
Current portion of other long-term assets	7	**69**	71
		7,450	7,167
Exploration and evaluation assets	3	**2,255**	2,208
Property, plant and equipment	4	**64,205**	64,581
Lease assets	5	**1,443**	1,458
Other long-term assets	7	**627**	541
		$ 75,980	$ 75,955
LIABILITIES			
Current liabilities			
Accounts payable		**$ 1,138**	$ 1,418
Accrued liabilities		**3,897**	3,534
Current portion of long-term debt	8	**1,809**	980
Current portion of other long-term liabilities	9	**1,641**	1,503
		8,485	7,435
Long-term debt	8	**9,231**	9,819
Other long-term liabilities	9	**8,571**	8,686
Deferred income taxes		**10,185**	10,183
		36,472	36,123
SHAREHOLDERS' EQUITY			
Share capital	11	**11,030**	10,712
Retained earnings		**28,273**	28,948
Accumulated other comprehensive income	12	**205**	172
		39,508	39,832
		$ 75,980	$ 75,955

Commitments and contingencies (note 16)

Approved by the Board of Directors on May 1, 2024.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Mar 31 2024**	Mar 31 2023
Product sales	17	**$ 9,422**	$ 9,548
Less: royalties		**(1,178)**	(918)
Revenue		**8,244**	8,630
Expenses			
Production		**2,157**	2,164
Transportation, blending and feedstock		**2,284**	2,334
Depletion, depreciation and amortization	4,5	**1,533**	1,418
Administration		**126**	106
Share-based compensation	9	**294**	66
Asset retirement obligation accretion	9	**97**	92
Interest and other financing expense		**138**	154
Risk management loss	15	**38**	21
Foreign exchange loss (gain)		**250**	(14)
(Gain) loss from investments	6	**(81)**	1
		6,836	6,342
Earnings before taxes		**1,408**	2,288
Current income tax expense	10	**401**	459
Deferred income tax expense	10	**20**	30
Net earnings		**$ 987**	$ 1,799
Net earnings per common share			
Basic	14	**$ 0.92**	$ 1.63
Diluted	14	**$ 0.91**	$ 1.62

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended **Mar 31 2024**	Mar 31 2023
Net earnings	**$ 987**	$ 1,799
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 (2023 – $nil)	**—**	—
Reclassification to net earnings, net of taxes of $nil (2023 – $nil)	**(1)**	(1)
	(1)	(1)
Foreign currency translation adjustment		
Translation of net investment	**34**	(1)
Other comprehensive income (loss), net of taxes	**33**	(2)
Comprehensive income	**$ 1,020**	$ 1,797

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Mar 31 2024	Mar 31 2023
Share capital	11		
Balance – beginning of period		**$ 10,712**	$ 10,294
Issued upon exercise of stock options		**175**	143
Previously recognized liability on stock options exercised for common shares		**211**	143
Purchase of common shares under Normal Course Issuer Bid		**(68)**	(84)
Balance – end of period		**11,030**	10,496
Retained earnings			
Balance – beginning of period		**28,948**	27,672
Net earnings		**987**	1,799
Dividends on common shares	11	**(1,124)**	(988)
Purchase of common shares under Normal Course Issuer Bid	11	**(538)**	(601)
Balance – end of period		**28,273**	27,882
Accumulated other comprehensive income	12		
Balance – beginning of period		**172**	209
Other comprehensive income (loss), net of taxes		**33**	(2)
Balance – end of period		**205**	207
Shareholders' equity		**$ 39,508**	$ 38,585

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Mar 31 2024**	Mar 31 2023
Operating activities			
Net earnings		**$ 987**	$ 1,799
Non-cash items			
Depletion, depreciation and amortization	4,5	**1,533**	1,418
Share-based compensation		**294**	66
Asset retirement obligation accretion		**97**	92
Unrealized risk management loss		**13**	20
Unrealized foreign exchange loss (gain)		**269**	(3)
(Gain) loss from investments	6	**(75)**	7
Deferred income tax expense		**20**	30
Abandonment expenditures	9	**(162)**	(137)
Other		**(93)**	(89)
Net change in non-cash working capital		**(15)**	(1,908)
Cash flows from operating activities		**2,868**	1,295
Financing activities			
Issue of bank credit facilities and commercial paper, net		**—**	588
Repayment of medium-term notes		**—**	(11)
Payment of lease liabilities	5	**(79)**	(67)
Issue of common shares on exercise of stock options	11	**175**	143
Dividends on common shares		**(1,076)**	(938)
Purchase of common shares under Normal Course Issuer Bid	11	**(606)**	(685)
Cash flows used in financing activities		**(1,586)**	(970)
Investing activities			
Net expenditures on exploration and evaluation assets	3,17	**(69)**	(28)
Net expenditures on property, plant and equipment	4,17	**(1,044)**	(1,229)
Net change in non-cash working capital		**(279)**	104
Cash flows used in investing activities		**(1,392)**	(1,153)
Decrease in cash and cash equivalents		**(110)**	(828)
Cash and cash equivalents – beginning of period		**877**	920
Cash and cash equivalents – end of period		**$ 767**	$ 92
Interest paid on long-term debt, net		**$ 181**	$ 168
Income taxes paid, net		**$ 198**	$ 1,556

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 and South Africa 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, 2023, except as disclosed in note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2023.

Critical Accounting Estimates and Judgements

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

2. CHANGE IN ACCOUNTING POLICIES

In January 2020, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" to clarify that liabilities are classified as either current or non-current, depending on the existence of the substantive right at the end of the reporting period for an entity to defer settlement of the liability for at least twelve months after the reporting period. In October 2022, the IASB issued further amendments to specify that the classification of debt as current or non-current at the reporting date is not affected by covenants to be complied with after the reporting date. The amendments were adopted on January 1, 2024 and had no impact on the Company's interim consolidated financial statements.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2023	$ 2,031	$ —	$ 100	$ 77	$ 2,208
Additions	**69**	**—**	**—**	**—**	**69**
Transfers to property, plant and equipment	**(23)**	**—**	**—**	**—**	**(23)**
Foreign exchange adjustments	**—**	**—**	**1**	**—**	**1**
At March 31, 2024	**$ 2,077**	**$ —**	**$ 101**	**$ 77**	**$ 2,255**

4. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2023	$ 83,483	$ 8,606	$ 4,409	$ 49,375	$ 484	$ 566	$ 146,923
Additions / Acquisitions	**634**	**4**	**41**	**353**	**4**	**10**	**1,046**
Transfers from exploration & evaluation assets	**23**	**—**	**—**	**—**	**—**	**—**	**23**
Derecognitions (1)	**(171)**	**—**	**—**	**(68)**	**—**	**—**	**(239)**
Foreign exchange adjustments and other	**—**	**215**	**109**	**—**	**—**	**—**	**324**
At March 31, 2024	**$ 83,969**	**$ 8,825**	**$ 4,559**	**$ 49,660**	**$ 488**	**$ 576**	**$ 148,077**
Accumulated depletion and depreciation							
At December 31, 2023	$ 58,840	$ 8,382	$ 3,358	$ 11,105	$ 213	$ 444	$ 82,342
Expense	**919**	**11**	**36**	**478**	**4**	**6**	**1,454**
Derecognitions (1)	**(171)**	**—**	**—**	**(68)**	**—**	**—**	**(239)**
Foreign exchange adjustments and other	**11**	**212**	**100**	**(8)**	**—**	**—**	**315**
At March 31, 2024	**$ 59,599**	**$ 8,605**	**$ 3,494**	**$ 11,507**	**$ 217**	**$ 450**	**$ 83,872**
Net book value							
At March 31, 2024	**$ 24,370**	**$ 220**	**$ 1,065**	**$ 38,153**	**$ 271**	**$ 126**	**$ 64,205**
At December 31, 2023	$ 24,643	$ 224	$ 1,051	$ 38,270	$ 271	$ 122	$ 64,581

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

5. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2023	$ 840	$ 482	$ 71	$ 65	$ 1,458
Additions	**5**	**17**	**31**	**9**	**62**
Depreciation	**(24)**	**(37)**	**(13)**	**(5)**	**(79)**
Foreign exchange adjustments and other	**—**	**—**	**3**	**(1)**	**2**
At March 31, 2024	**$ 821**	**$ 462**	**$ 92**	**$ 68**	**$ 1,443**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at March 31, 2024 were as follows:

	Mar 31 2024	Dec 31 2023
Lease liabilities	**$ 1,535**	$ 1,555
Less: current portion	**285**	298
	$ 1,250	$ 1,257

Total cash outflows for leases for the three months ended March 31, 2024, including payments related to short-term leases not reported as lease assets, were $336 million (three months ended March 31, 2023 – $337 million). Interest expense on leases for the three months ended March 31, 2024 was $17 million (three months ended March 31, 2023 – $16 million).

6. INVESTMENTS

As at March 31, 2024, the Company had the following investment:

	Mar 31 2024	Dec 31 2023
Investment in PrairieSky Royalty Ltd.	**$ 600**	$ 525

The (gain) loss from investment was comprised as follows:

	Three Months Ended	
	Mar 31 2024	Mar 31 2023
(Gain) loss from investment	**$ (75)**	$ 7
Dividend income	**(6)**	(6)
	$ (81)	$ 1

The Company's 22.6 million common share investment in PrairieSky Royalty Ltd. does not constitute significant influence, and is accounted for at fair value through profit or loss, measured at each reporting date. As at March 31, 2024, the market price per common share was $26.53 (December 31, 2023 – $23.20; March 31, 2023 – $21.40).

7. OTHER LONG-TERM ASSETS

	Mar 31 2024	Dec 31 2023
Long-term prepayments, contracts and other [(1)]	**$ 377**	$ 279
Prepaid cost of service tolls	**172**	179
Long-term inventory	**144**	141
Risk management (note 15)	**3**	13
	696	612
Less: current portion	**69**	71
	$ 627	$ 541

(1) Includes physical product sales contracts, accrued interest on the deferred PRT recovery, and the unamortized portion of the Company's share bonus program.

The Company has a 50% equity investment in NWRP. NWRP operates a 50,000 barrels per day bitumen upgrader and refinery that processes approximately 12,500 barrels per day (25% toll payer) of bitumen feedstock for the Company and 37,500 barrels per day (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), 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 16). Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 17).

The carrying value of the Company's interest in NWRP is $nil, and as at March 31, 2024, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $551 million (December 31, 2023 – $555 million). For the three months ended March 31, 2024, the Company's recovery of its share of unrecognized equity losses was $4 million (three months ended March 31, 2023 – unrecognized equity loss of $16 million).

8. LONG-TERM DEBT

	Mar 31 2024	Dec 31 2023
Canadian dollar denominated debt, unsecured		
Medium-term notes	**$ 1,286**	$ 1,286
US dollar denominated debt, unsecured		
US dollar debt securities (March 31, 2024 – US$7,250 million; December 31, 2023 – US$7,250 million)	**9,811**	9,573
Long-term debt before transaction costs and original issue discounts, net	**11,097**	10,859
Less: original issue discounts, net [(1)]	**10**	11
transaction costs [(1) (2)]	**47**	49
	11,040	10,799
Less: current portion of long-term debt [(1) (2)]	**1,809**	980
	$ 9,231	$ 9,819

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

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

Bank Credit Facilities and Commercial Paper

As at March 31, 2024, the Company had undrawn revolving bank credit facilities of $5,450 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $500 million revolving credit facility, maturing February 2025;
- a $2,425 million revolving syndicated credit facility, maturing June 2025; and
- a $2,425 million revolving syndicated credit facility, maturing June 2027.

Borrowings under the Company's revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, 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 total long-term debt outstanding for the three months ended March 31, 2024 was 4.8% (March 31, 2023 – 4.7%).

As at March 31, 2024, letters of credit and guarantees aggregating to $734 million were outstanding (December 31, 2023 – $446 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 March 31, 2024, the Company repaid US$500 million of 3.80% US dollar debt securities due April 15, 2024.

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.

9. OTHER LONG-TERM LIABILITIES

	Mar 31 2024	Dec 31 2023
Asset retirement obligations	**$ 7,667**	$ 7,690
Lease liabilities (note 5)	**1,535**	1,555
Share-based compensation	**859**	780
Transportation and processing contracts	**77**	87
Risk management (note 15)	**6**	4
Other	**68**	73
	10,212	10,189
Less: current portion	**1,641**	1,503
	$ 8,571	$ 8,686

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 5.2% (December 31, 2023 – 5.2%) and inflation rates of up to 2% (December 31, 2023 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Mar 31 2024	Dec 31 2023
Balance – beginning of period	**$ 7,690**	$ 6,908
Liabilities incurred	**6**	25
Liabilities disposed, net	**(4)**	—
Liabilities settled	**(162)**	(509)
Asset retirement obligation accretion	**97**	366
Revision of cost, inflation and timing estimates (1)	**—**	621
Change in discount rates	**—**	314
Foreign exchange adjustments	**40**	(35)
Balance – end of period	**7,667**	7,690
Less: current portion	**659**	634
	$ 7,008	$ 7,056

(1) Includes normal course revisions of cost, inflation and timing estimates, as well as revisions related to cost estimate increases in 2023 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") plans. 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, and by individual employee performance and the extent to which certain other performance measures are met.

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

	Mar 31 2024	Dec 31 2023
Balance – beginning of period	**$ 780**	$ 832
Share-based compensation expense	**294**	491
Cash payment for stock options surrendered and PSUs vested	**(6)**	(110)
Transferred to common shares	**(211)**	(435)
Other	**2**	2
Balance – end of period	**859**	780
Less: current portion	**667**	538
	$ 192	$ 242

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended	
Expense (recovery)	**Mar 31 2024**	Mar 31 2023
Current corporate income tax – North America [1]	**$ 412**	$ 480
Current corporate income tax – North Sea	**(5)**	6
Current corporate income tax – Offshore Africa	**5**	10
Current PRT [2] – North Sea	**(14)**	(40)
Other taxes	**3**	3
Current income tax	**401**	459
Deferred corporate income tax	**14**	23
Deferred PRT [2] – North Sea	**6**	7
Deferred income tax	**20**	30
Income tax	**$ 421**	$ 489

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

(2) Petroleum Revenue Tax.

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Three Months Ended Mar 31, 2024	
Issued Common Shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,072,408**	**$ 10,712**
Issued upon exercise of stock options	**4,255**	**175**
Previously recognized liability on stock options exercised for common shares	**—**	**211**
Purchase of common shares under Normal Course Issuer Bid	**(6,675)**	**(68)**
Balance – end of period	**1,069,988**	**$ 11,030**

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 February 28, 2024, the Board of Directors approved a 5% increase in the quarterly dividend to $1.05 per common share, beginning with the dividend paid on April 5, 2024.

On November 1, 2023, the Board of Directors approved an 11% increase in the quarterly dividend to $1.00 per common share. On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.90 per common share.

Normal Course Issuer Bid

On March 8, 2024, 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, up to 90,231,429 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2024 and ending March 12, 2025.

For the three months ended March 31, 2024, the Company purchased 6,675,000 common shares at a weighted average price of $90.78 per common share for a total cost of $606 million. Retained earnings were reduced by $538 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2024, up to and including April 30, 2024, the Company purchased 2,750,000 common shares at a weighted average price of $107.16 per common share for a total cost of $295 million.

Share Split

On February 28, 2024, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval and the Company having obtained all regulatory approvals, including TSX approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 2, 2024.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding as at March 31, 2024:

	Three Months Ended Mar 31, 2024	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**26,205**	**$ 53.60**
Granted	**6,956**	**$ 88.79**
Exercised for common shares	**(4,255)**	**$ 41.22**
Surrendered for cash settlement	**(128)**	**$ 44.06**
Forfeited	**(492)**	**$ 57.91**
Outstanding – end of period	**28,286**	**$ 64.08**
Exercisable – end of period	**4,104**	**$ 47.99**

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

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Mar 31 2024	Mar 31 2023
Derivative financial instruments designated as cash flow hedges	**$ 71**	$ 74
Foreign currency translation adjustment	**134**	133
	$ 205	$ 207

13. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the ratio of current and long-term debt less cash and cash equivalents divided by the sum of the carrying value of shareholders' equity plus current and long-term debt less cash and cash equivalents. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. As at March 31, 2024, the ratio was below the target range at 20.6%.

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.

	Mar 31 2024	Dec 31 2023
Long-term debt	**$ 11,040**	$ 10,799
Less: cash and cash equivalents	**767**	877
Long-term debt, net	**$ 10,273**	$ 9,922
Total shareholders' equity	**$ 39,508**	$ 39,832
Debt to book capitalization	**20.6%**	19.9%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at March 31, 2024, the Company was in compliance with this covenant.

14. NET EARNINGS PER COMMON SHARE

		Three Months Ended	
		Mar 31 2024	Mar 31 2023
Weighted average common shares outstanding – basic (thousands of shares)		**1,071,043**	1,100,463
Effect of dilutive stock options (thousands of shares)		**8,599**	11,579
Weighted average common shares outstanding – diluted (thousands of shares)		**1,079,642**	1,112,042
Net earnings		**$ 987**	$ 1,799
Net earnings per common share	– basic	**$ 0.92**	$ 1.63
	– diluted	**$ 0.91**	$ 1.62

15. FINANCIAL INSTRUMENTS

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

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

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

Asset (liability)	**Mar 31 2024**	Dec 31 2023
Balance – beginning of period	**$ 9**	$ 6
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities (1) (2)	**(12)**	3
Balance – end of period	**(3)**	9
Less: current portion	**(3)**	8
	$ —	$ 1

(1) Risk management assets and liabilities are disclosed in note 7 and note 9, respectively.

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

Net loss from risk management activities was as follows:

	Three Months Ended	
	Mar 31 2024	Mar 31 2023
Net realized risk management loss	**$ 25**	$ 1
Net unrealized risk management loss	**13**	20
	$ 38	$ 21

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. There were no transfers between Level 1, 2, and 3 financial instruments. The fair values of the Company's fixed rate long-term debt is outlined below:

	Mar 31, 2024	
	Carrying amount	**Level 1 Fair Value**
Fixed rate long-term debt (1) (2)	**$ 11,040**	**$ 10,968**

(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.

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, 2023.

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.

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. At March 31, 2024, 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.

As at March 31, 2024, the Company had US$1,007 million of foreign currency forward contracts outstanding (December 31, 2023 – US$1,003 million), with original terms of up to 90 days, all of which were designated as derivatives held for trading.

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and, where appropriate, ensuring that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at March 31, 2024, substantially all of the Company's accounts receivable were due within normal trade terms.

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

c) Liquidity risk

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

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

As at March 31, 2024, 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	$ 1,138	$ —	$ —	$ —
Accrued liabilities	$ 3,897	$ —	$ —	$ —
Long-term debt (1)	$ 1,809	$ 812	$ 2,357	$ 6,119
Other long-term liabilities (2)	$ 291	$ 198	$ 425	$ 627
Interest and other financing expense (3)	$ 579	$ 504	$ 1,294	$ 3,312

(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, $285 million; one to less than two years, $198 million; two to less than five years, $425 million; and thereafter, $627 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 March 31, 2024.

16. COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at March 31, 2024:

	Remaining 2024	2025	2026	2027	2028	Thereafter
Product transportation and processing (1)	$ 1,244	$ 1,675	$ 1,530	$ 1,462	$ 1,347	$ 13,621
North West Redwater Partnership service toll (2)	$ 117	$ 156	$ 138	$ 124	$ 128	$ 4,933
Offshore vessels and equipment	$ 28	$ 35	$ —	$ —	$ —	$ —
Field equipment and power	$ 38	$ 25	$ 23	$ 22	$ 22	$ 193
Other	$ 123	$ 111	$ 111	$ 25	$ 26	$ 355

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

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $2,922 million of interest payable over the 40-year tolling period, ending in 2058 (note 7).

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

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

17. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America Three Months Ended Mar 31		North Sea Three Months Ended Mar 31		Offshore Africa Three Months Ended Mar 31		Total Exploration and Production Three Months Ended Mar 31	
	2024	2023	**2024**	2023	**2024**	2023	**2024**	2023
Segmented product sales								
Crude oil and NGLs	**4,284**	3,749	**139**	—	**82**	92	**4,505**	3,841
Natural gas	**485**	807	**1**	3	**13**	12	**499**	822
Other income and revenue [1]	**(2)**	11	**4**	—	**—**	2	**2**	13
Total segmented product sales	**4,767**	4,567	**144**	3	**95**	106	**5,006**	4,676
Less: royalties	**(583)**	(491)	**—**	—	**(5)**	(10)	**(588)**	(501)
Segmented revenue	**4,184**	4,076	**144**	3	**90**	96	**4,418**	4,175
Segmented expenses								
Production	**909**	1,002	**106**	3	**21**	27	**1,036**	1,032
Transportation, blending and feedstock	**1,559**	1,546	**1**	—	**—**	—	**1,560**	1,546
Depletion, depreciation and amortization	**941**	890	**17**	1	**47**	35	**1,005**	926
Asset retirement obligation accretion	**58**	59	**16**	11	**2**	2	**76**	72
Risk management loss (commodity derivatives)	**3**	20	**—**	—	**—**	—	**3**	20
Total segmented expenses	**3,470**	3,517	**140**	15	**70**	64	**3,680**	3,596
Segmented earnings (loss)	**714**	559	**4**	(12)	**20**	32	**738**	579
Non-segmented expenses								
Administration								
Share-based compensation								
Interest and other financing expense								
Risk management loss (other)								
Foreign exchange loss (gain)								
(Gain) loss from investments								
Total non-segmented expenses								
Earnings before taxes								
Current income tax								
Deferred income tax								
Net earnings								

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading Three Months Ended Mar 31		Midstream and Refining Three Months Ended Mar 31		Inter–segment elimination and other Three Months Ended Mar 31		Total Three Months Ended Mar 31	
	2024	2023	**2024**	2023	**2024**	2023	**2024**	2023
Segmented product sales								
Crude oil and NGLs [(2)]	**4,168**	4,482	**20**	21	**(17)**	68	**8,676**	8,412
Natural gas	**—**	—	**—**	—	**30**	29	**529**	851
Other income and revenue [(1)]	**1**	19	**214**	250	**—**	3	**217**	285
Total segmented product sales	**4,169**	4,501	**234**	271	**13**	100	**9,422**	9,548
Less: royalties	**(590)**	(417)	**—**	—	**—**	—	**(1,178)**	(918)
Segmented revenue	**3,579**	4,084	**234**	271	**13**	100	**8,244**	8,630
Segmented expenses								
Production	**1,026**	1,042	**79**	78	**16**	12	**2,157**	2,164
Transportation, blending and feedstock [(2)]	**568**	550	**158**	153	**(2)**	85	**2,284**	2,334
Depletion, depreciation and amortization	**524**	488	**4**	4	**—**	—	**1,533**	1,418
Asset retirement obligation accretion	**21**	20	**—**	—	**—**	—	**97**	92
Risk management loss (commodity derivatives)	**—**	—	**—**	—	**—**	—	**3**	20
Total segmented expenses	**2,139**	2,100	**241**	235	**14**	97	**6,074**	6,028
Segmented earnings (loss)	**1,440**	1,984	**(7)**	36	**(1)**	3	**2,170**	2,602
Non-segmented expenses								
Administration							**126**	106
Share-based compensation							**294**	66
Interest and other financing expense							**138**	154
Risk management loss (other)							**35**	1
Foreign exchange loss (gain)							**250**	(14)
(Gain) loss from investments							**(81)**	1
Total non-segmented expenses							**762**	314
Earnings before taxes							**1,408**	2,288
Current income tax							**401**	459
Deferred income tax							**20**	30
Net earnings							**987**	1,799

(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]

	Three Months Ended					
	Mar 31, 2024			Mar 31, 2023		
	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	**$ 69**	**$ (23)**	**$ 46**	$ 28	$ (10)	$ 18
	69	**(23)**	**46**	28	(10)	18
Property, plant and equipment						
Exploration and Production						
North America	**632**	**(146)**	**486**	856	(189)	667
North Sea	**4**	**—**	**4**	3	—	3
Offshore Africa	**41**	**—**	**41**	23	—	23
	677	**(146)**	**531**	882	(189)	693
Oil Sands Mining and Upgrading	**353**	**(68)**	**285**	336	(50)	286
Midstream and Refining	**4**	**—**	**4**	3	—	3
Head Office	**10**	**—**	**10**	8	—	8
	1,044	**(214)**	**830**	1,229	(239)	990
	$ 1,113	**$ (237)**	**$ 876**	$ 1,257	$ (249)	$ 1,008

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

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

Segmented Assets

	Mar 31 2024	Dec 31 2023
Exploration and Production		
North America	**$ 30,530**	$ 30,058
North Sea	**483**	602
Offshore Africa	**1,383**	1,380
Other	**111**	32
Oil Sands Mining and Upgrading	**42,327**	42,865
Midstream and Refining	**977**	856
Head Office	**169**	162
	$ 75,980	$ 75,955

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 March 31, 2024:	
Interest coverage (times)	
Net earnings [(1)]	16.0x
Adjusted funds flow [(2)]	28.1x

(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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Mark A. Stainthorpe
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Robin S. Zabek
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Senior Vice-President, Canadian Conventional Field Operations

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Senior Vice-President, Exploration

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Senior Vice-President, Safety, Risk Management and Innovation

Ron K. Laing
Senior Vice-President, Corporate Development and Land

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Senior Vice-President, Exploitation

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Vice-President, Corporate Development and Commercial Operations

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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