Canadian Natural

FOURTH QUARTER REPORT

YEAR ENDED DECEMBER 31, 2023 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2023 FOURTH QUARTER AND YEAR END RESULTS

Highlighting a successful 2023, Canadian Natural's Chief Financial Officer, Mark Stainthorpe, stated "Through the Company's effective and efficient operations and disciplined capital allocation, we achieved our net debt level of $10 billion in Q4/23, earlier than previously forecasted. As per our free cash flow allocation policy, we will now target to return 100% of free cash flow to shareholders through dividends and share buybacks."

Canadian Natural's Vice Chairman, Tim McKay, also commented "In 2023, we delivered on our capital allocation strategy by strengthening our balance sheet, providing significant returns to shareholders and strategically developing our assets. We achieved record annual production while growing our reserves organically on both a total proved and total proved plus probable basis, with reserve replacement ratios of 166% and 194% respectively.

Our strong execution in 2023 sets us up to continue delivering on our four pillars of capital allocation through our disciplined 2024 capital budget of approximately $5.4 billion. This budget is strategically weighted to longer cycle thermal development in the first half of 2024 and shorter cycle growth in the second half of the year, targeting strong exit production levels. As well it provides us with the flexibility to adjust to changing market egress and evolving market conditions, ensuring we are allocating capital effectively and maximizing value for our shareholders.

We are committed to supporting Canada's and Alberta's climate goals and continue to reduce our environmental footprint with our robust environmental targets, including net zero greenhouse gas ("GHG") emissions in the oil sands by 2050. We are uniquely positioned with diverse, long life low decline assets which are ideal to apply technologies, to reduce GHG emissions and provide industry leading environmental performance. It is important to continue working together with the Canadian and the 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 President, Scott Stauth, also commented "The Company delivered strong operational results in 2023 and achieved multiple production records, including record annual average total production of approximately 1,332 MBOE/d, representing 7% production per share growth as a result of safe, effective and efficient operations and significant share repurchases. We also achieved record quarterly average total production of approximately 1,419 MBOE/d in Q4/23. With our focus on continuous improvement and process optimization, we had high reliability and utilization at our oil sands mining operations, achieving record synthetic crude oil ("SCO") production of approximately 500 Mbbl/d in Q4/23.

One of Canadian Natural's advantages is our significant reserves base, with total proved reserves of 13.9 billion BOE and total proved plus probable reserves of 18.5 billion BOE as of year end 2023, which increased 2% and 3% respectively from year end 2022. The increase in our reserves reflects the success of our capital efficient development opportunities across our asset base. With approximately 75% of the Company's total proved reserves being long life low decline, the strength and depth of our assets is evident and provides us with a total proved reserves life index of 32 years and a total proved plus probable reserves life index of 43 years."

Mark Stainthorpe also added “In 2023, we successfully executed on our capital program and remained focused on cost control in an inflationary environment. We delivered strong financial results in 2023, including net earnings of approximately $8.2 billion and adjusted funds flow of $15.3 billion, which drove significant returns to shareholders totaling $7.2 billion.

In the past three years, we have reduced our net debt by over $11 billion and delivered approximately $21.5 billion directly to shareholders through $11.0 billion in dividends and $10.5 billion in share repurchases. These impressive results delivered returns to shareholders of approximately $30 per share through debt reductions and shareholder distributions over the three year time period.

Subsequent to quarter end, the Board of Directors approved a 5% increase to our quarterly dividend to $1.05 per common share, up from the previous dividend level of $1.00 per common share, payable on April 5, 2024 to shareholders of record on March 15, 2024. This demonstrates the confidence that the Board has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline reserves and asset base. With this increase announced today, we have increased our quarterly dividend 24% through three separate increases over the past year. This year marks the 24^{th} consecutive year of dividend increases, with a compound annual growth rate ("CAGR") of 21% over that time.

In addition, our Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval and 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.

With our disciplined 2024 capital budget, low maintenance capital requirements and a long life low decline asset base, we target to deliver strong returns on capital with robust free cash flow while continuing to provide significant returns to shareholders in 2024."

HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Dec 31 2023**	Sep 30 2023	Dec 31 2022	Year Ended **Dec 31 2023**	Dec 31 2022
Net earnings	**$ 2,627**	$ 2,344	$ 1,520	**$ 8,233**	$ 10,937
Per common share – basic	**$ 2.43**	$ 2.15	$ 1.37	**$ 7.54**	$ 9.64
– diluted	**$ 2.41**	$ 2.13	$ 1.36	**$ 7.47**	$ 9.52
Adjusted net earnings from operations (1)	**$ 2,546**	$ 2,850	$ 2,194	**$ 8,533**	$ 12,863
Per common share – basic (2)	**$ 2.36**	$ 2.61	$ 1.98	**$ 7.82**	$ 11.33
– diluted (2)	**$ 2.34**	$ 2.59	$ 1.96	**$ 7.74**	$ 11.19
Cash flows from operating activities	**$ 4,815**	$ 3,498	$ 4,544	**$ 12,353**	$ 19,391
Adjusted funds flow (1)	**$ 4,419**	$ 4,684	$ 4,176	**$ 15,274**	$ 19,791
Per common share – basic (2)	**$ 4.09**	$ 4.30	$ 3.78	**$ 14.00**	$ 17.44
– diluted (2)	**$ 4.05**	$ 4.26	$ 3.73	**$ 13.86**	$ 17.22
Cash flows used in investing activities	**$ 946**	$ 1,199	$ 1,262	**$ 4,858**	$ 4,987
Net capital expenditures (3)	**$ 975**	$ 1,108	$ 1,233	**$ 4,909**	$ 5,136
Abandonment expenditures, net (1)	**$ 149**	$ 123	$ 84	**$ 509**	$ 335
Daily production, before royalties					
Natural gas (MMcf/d)	**2,231**	2,151	2,115	**2,151**	2,090
Crude oil and NGLs (bbl/d)	**1,047,541**	1,035,153	942,258	**973,530**	933,149
Equivalent production (BOE/d) (4)	**1,419,313**	1,393,614	1,294,679	**1,332,105**	1,281,434

(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 and year ended December 31, 2023 dated February 28, 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 and year ended December 31, 2023 dated February 28, 2024.

(3) 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 the Company's MD&A for the three months and year ended December 31, 2023 dated February 28, 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.

ANNUAL HIGHLIGHTS

- 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 2023, the Company generated strong annual financial results, including:
  - Net earnings of approximately $8.2 billion and adjusted net earnings from operations of approximately $8.5 billion.
  - Cash flows from operating activities of approximately $12.4 billion.
  - Adjusted funds flow of approximately $15.3 billion.
  - Free cash flow[1] of approximately $6.9 billion after total dividend payments of $3.9 billion, base capital expenditures[2] of $4.0 billion and $0.5 billion in abandonment expenditures.
- Canadian Natural achieved its $10 billion net debt level and as a result, is targeting to return 100% of free cash flow to shareholders, per the free cash flow allocation policy.
- The Company remained disciplined in 2023, meeting its annual targeted net capital expenditures of approximately $4.9 billion and $0.5 billion in abandonment expenditures.

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this press release and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2023, dated February 28, 2024.

(2) Item is a component of net capital expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2023 for more details on net capital expenditures.

- In 2023, Canadian Natural continued to focus on safe, effective and efficient operations, delivering record annual average production of 1,332,105 BOE/d, an increase of 4% from 2022 levels, or 7% on a production per share basis.
  - The Company delivered record annual total liquids production of 973,530 bbl/d in 2023, an increase of 4% or approximately 40,400 bbl/d from 2022 levels. Strong annual liquids production in 2023 was driven by:
    - Record annual Oil Sands Mining and Upgrading production of 451,339 bbl/d, an increase of 6% or approximately 25,400 bbl/d from 2022 levels as a result of the Company's focus on continuous improvement and increased reliability.
    - The Company also achieved record annual thermal production of 262,000 bbl/d, an increase of 4% or approximately 10,000 bbl/d from 2022 levels as a result of the Company's capital efficient thermal pad add development program.
  - The Company achieved record annual natural gas production of 2,151 MMcf/d, an increase of 3% or approximately 61 MMcf/d from 2022 levels, reflecting strong results from our capital efficient drill to fill development plan.
- Canadian Natural continues to maintain a strong balance sheet and financial flexibility, ending the year with approximately $9.9 billion in net debt, with significant liquidity(1) of approximately $6.9 billion. The Company executed on a number of initiatives in 2023 to strengthen its financial flexibility, including:
  - In Q2/23, the Company extended its $2.425 billion revolving syndicated credit facility originally maturing June 2024 to June 2027.
  - In Q3/23, the Company extended its $0.5 billion revolving credit facility originally maturing February 2024 to February 2025.
- In Q4/23, the Company repaid $0.405 billion of 1.45% medium-term notes.

RETURNS TO SHAREHOLDERS

- Returns to shareholders in 2023 were significant, having directly returned to shareholders approximately $7.2 billion, comprised of $3.9 billion in dividends and $3.3 billion in share repurchases as a result of the Company's ability to generate substantial free cash flow.
  - In 2023, the Company repurchased a total of approximately 40.1 million common shares for cancellation at a weighted average price of $82.86 per share for a total of $3.3 billion.
- With the Company's net debt below $10 billion at year end 2023, the Company is now targeting in 2024 to return 100% of free cash flow to shareholders through dividends and share repurchases, per our free cash flow allocation policy. Going forward, the Company will manage this allocation of free cash flow on a forward looking annual basis, while managing working capital and cash management as required.
- Subsequent to quarter end, the Board of Directors approved a 5% increase to the quarterly dividend to $1.05 per common share, up from the previous dividend level of $1.00 per common share, payable on April 5, 2024 to shareholders of record on March 15, 2024. This demonstrates the confidence that the Board has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline reserves and asset base.
  - Since March 2, 2023, the Company has increased its quarterly dividend 24% through three separate increases for a combined increase of $0.20 per share.
  - The Company's leading track record of dividend increases continues, with 2024 marking the 24th consecutive year of dividend increases with a compound annual growth rate ("CAGR") of 21% over that time.
- To date in 2024, up to and including February 28, 2024, the Company has returned a total of approximately $1.4 billion directly to shareholders through $1.1 billion in dividends and $0.35 billion from the repurchase and cancellation of approximately 4.1 million common shares.
- On February 28, 2024, the Board of Directors approved the renewal of the Company's NCIB, which states that during the 12 month period commencing March 13, 2024 and ending March 12, 2025, the Company can repurchase for cancellation up to 10% of the public float (determined in accordance with the rules of the TSX), subject to TSX approval.

(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 and year ended December 31, 2023, dated February 28, 2024.

- 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 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.

QUARTERLY HIGHLIGHTS

- In Q4/23, the Company generated strong quarterly financial results, including:
  - Net earnings of approximately $2.6 billion and adjusted net earnings from operations of approximately $2.5 billion.
  - Cash flows from operating activities of approximately $4.8 billion.
  - Adjusted funds flow of approximately $4.4 billion.
  - Free cash flow of approximately $2.5 billion after total dividend payments of $1.0 billion and base capital expenditures of $0.8 billion and $0.1 billion in abandonment expenditures.
- Direct returns to shareholders in Q4/23 were strong, totaling approximately $2.5 billion, comprised of $1.0 billion of dividends and $1.5 billion through the repurchase and cancellation of approximately 17.6 million common shares at a weighted average price of $88.26 per share.
- In Q4/23, Canadian Natural achieved record quarterly average production volumes of 1,419,313 BOE/d, an increase of 10% or approximately 125,000 BOE/d compared to Q4/22 levels.
  - The Company achieved record quarterly average liquids production volumes in Q4/23 of 1,047,541 bbl/d, an increase of 11% or approximately 105,000 bbl/d over Q4/22 levels.
    - Oil Sands Mining and Upgrading achieved record quarterly average production of 500,133 bbl/d in Q4/23, an increase of 17% from Q4/22 levels as a result of the Company's focus on continuous improvements and increased reliability.
  - The Company delivered record quarterly natural gas production volumes of 2,231 MMcf/d in Q4/23, an increase of 5% compared to Q4/22 levels, reflecting strong results from our capital efficient drill to fill development plan.

RESERVES HIGHLIGHTS

A key differentiator for Canadian Natural is the strength, diversity and balance of its world class, top tier assets. The Company's total proven reserve life index ("RLI")(1) of 32 years is supported by long life low decline assets that have been strategically assembled and developed over several decades. The low maintenance capital requirements relative to the size and quality of the reserves affords the Company significant flexibility when balancing its four pillars of capital allocation to maximize shareholder value.

The Company's reserves were evaluated and reviewed by Independent Qualified Reserves Evaluators ("IQREs"). The following highlights are based on the Company's reserves using forecast prices and costs at December 31, 2023 (all reserves values are Company Gross unless stated otherwise).

- Total proved reserves increased 2% to 13.910 billion BOE, with reserves additions and revisions of 0.809 billion BOE. Total proved plus probable reserves increased 3% to 18.504 billion BOE, with reserves additions and revisions of 0.944 billion BOE.
  - The strength and depth of the Company's assets are evident as approximately 75% of total proved reserves are long life low decline reserves. This results in a total proved BOE RLI of 32 years and a total proved plus probable BOE RLI of 43 years.
    - Additionally, high value, zero decline SCO represents approximately 50% of total proved reserves with a RLI of 44 years.
- Proved developed producing reserves additions and revisions are 540 million BOE, replacing 2023 production by 111%. The proved developed producing BOE RLI is 21 years.
- Total proved reserves additions and revisions replaced 2023 production by 166%. Total proved plus probable reserves additions and revisions replaced 2023 production by 194%.
- In 2023, Canadian Natural continued to achieve strong finding and development costs:

- Finding, development and acquisition ("FD&A")[(1)] costs, excluding changes in Future Development Cost ("FDC"), are $5.86/BOE for total proved reserves and $5.02/BOE for total proved plus probable reserves.
- FD&A costs, including changes in FDC, are $9.25/BOE for total proved reserves and $8.28/BOE for total proved plus probable reserves.

▪ The net present value of future net revenues, before income tax, discounted at 10%, is $105.9 billion for proved developed producing reserves, $153.7 billion for total proved reserves, and $186.5 billion for total proved plus probable reserves.
  - The Company's total proved net asset value ("NAV") per share increased to $139.07 per share in 2023 from $131.79 per share in 2022 after adjusting for asset retirement obligations and net debt. Total proved plus probable NAV per share increased to $169.65 per share in 2023 from $161.53 per share in 2022.

CORPORATE UPDATE

Canadian Natural is pleased to announce the appointment of Ms. Christine Healy to the Board of Directors of the Company, effective February 28, 2024. Ms. Healy is currently the President, AMEA (Asia, Middle East and Australia) of AtkinsRealis, a globally-leading design, engineering and project-management company headquartered in Montreal, Canada. Prior to that, she served as Senior Vice President, Carbon Neutrality and Continental Europe for TotalEnergies from 2021 to 2023. From 2018 to 2020, Ms. Healy served as Country Chair, President and Chief Executive Officer for Total E&P Canada. Prior to her tenure with TotalEnergies, Ms. Healy was Chief Strategy Officer and General Counsel of Maersk Oil and Gas where she was responsible for M&A, strategy, commercial, communications, government relations, compliance and legal. She has also held senior executive positions with Equinor and the Government of Newfoundland and Labrador. Ms. Healy holds a B.A. (Hon.), Economics from Memorial University and a Juris Doctor from Osgoode Hall Law School.

As part of the Company's previously announced management changes, Scott Stauth was promoted to President of Canadian Natural and joined the Board of Directors effective February 28, 2024. Additionally, Tim McKay, Vice Chairman, has resigned from the Board of Directors and will continue to support the management transition until his retirement.

(1) Supplementary financial measure. Refer to the "2023 Year End Reserves" section of this document.

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 73% of total liquids production in 2023, 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	Year Ended December 31			
	2023		2022	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil [1]	**228**	**221**	332	317
Natural gas	**78**	**61**	100	72
Dry	**2**	**2**	1	1
Subtotal	**308**	**284**	433	390
Stratigraphic test / service wells	**481**	**419**	530	452
Total	**789**	**703**	963	842
Success rate (excluding stratigraphic test / service wells)		**99%**		99%

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 284 net crude oil and natural gas producer wells in 2023 compared to 390 net wells in 2022, a decrease of 106 net wells over this time period.

2024 BUDGET STRATEGY

Canadian Natural's unique and diversified asset base provides a key competitive advantage as it can manage the pace and timing of development activities to maximize value growth from our assets. The Company reiterates its disciplined 2024 capital budget at approximately $5.4 billion[1] and targets to provide production growth in 2024, 2025 and beyond.

In 2024, the drilling program is strategically weighted toward longer cycle projects, primarily thermal in situ pads, in the first half of the year, and shorter cycle development opportunities in the second half of the year to better align with incremental market egress, maximizing value for shareholders.

(1) Forward looking 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 the Company's MD&A for the three months and year ended December 31, 2023 dated February 28, 2024.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Crude oil and NGLs production (bbl/d)	**243,157**	232,496	233,371	**234,100**	227,953
Net wells targeting crude oil	**42**	42	71	**173**	214
Net successful wells drilled	**42**	42	71	**171**	213
Success rate	**100%**	100%	100%	**99%**	99%

- Annual North America E&P liquids production, excluding thermal in situ, averaged 234,100 bbl/d in 2023, a 3% increase compared to 2022 levels. The increase in production from the prior periods primarily reflects growth in the Company's primary heavy crude oil and liquids-rich Montney assets, partially offset by the impacts of wildfires, a third party pipeline outage and natural field declines.
  - Primary heavy crude oil production averaged 77,668 bbl/d in 2023, a 15% increase from 2022 levels, reflecting strong drilling results from the Company's multilateral wells in the Mannville and Clearwater fairways. The Company drilled 104 horizontal multilateral primary heavy crude oil wells in 2023.
    - Operating costs[1] in the Company's primary heavy crude oil operations averaged $19.85/bbl (US$14.71/bbl) in 2023, a decrease of 9% from 2022 levels, primarily reflecting lower energy costs.
  - Pelican Lake production averaged 46,046 bbl/d in 2023, a decrease of 5% from 2022 levels, reflecting historical low natural field declines from this long life low decline asset.
    - Operating costs at Pelican Lake averaged $8.58/bbl (US$6.36/bbl) in 2023, an increase of 3% compared to 2022 levels, primarily due to lower volumes.
  - North America light crude oil and NGLs production averaged 109,354 bbl/d in 2023, comparable to 2022 levels, reflecting strong liquids results, primarily from the Montney, which offset the impacts of wildfires, a third party pipeline outage and natural field declines.
    - Operating costs in the Company's North America light crude oil and NGLs operations averaged $16.28/bbl (US$12.06/bbl) in 2023, an increase of 2% over 2022 levels, reflecting higher service costs.

North America Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Natural gas production (MMcf/d)	**2,218**	2,139	2,105	**2,139**	2,075
Net wells targeting natural gas	**9**	10	15	**61**	72
Net successful wells drilled	**9**	10	15	**61**	72
Success rate	**100%**	100%	100%	**100%**	100%

- Canadian Natural achieved record annual North America natural gas production of 2,139 MMcf/d in 2023, an increase of 3% from 2022 levels. This growth reflects strong drilling results from the Company's capital efficient drill to fill development plan, which was partially offset by the impacts from wildfires, a third party pipeline outage and natural field declines.
  - North America natural gas operating costs averaged $1.27/Mcf in 2023, a 7% increase compared to 2022 levels, primarily reflecting higher service costs. The Company continues to focus on cost control and effective and efficient operations to offset cost pressures.

(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			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Bitumen production (bbl/d)	**278,422**	287,085	253,188	**262,000**	252,018
Net wells targeting bitumen	**—**	2	9	**50**	104
Net successful wells drilled	**—**	2	9	**50**	104
Success rate	**—%**	100%	100%	**100%**	100%

- Record annual thermal in situ production levels averaged 262,000 bbl/d in 2023, an increase of 4% from 2022 levels. The increase in thermal in situ production is driven by strong execution on the Company's strategic development plan, including capital efficient pad additions at Primrose and Kirby in 2023, partially offset by natural field declines.
  - Thermal in situ operating costs averaged $13.17/bbl (US$9.76/bbl) in 2023, a decrease of 20% from 2022 levels, primarily reflecting the impact of higher production volumes and lower energy costs.
- At Jackfish and Kirby North, planned turnarounds are targeted to occur in Q2/24, impacting quarterly average production by approximately 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, reliable, thermal in situ production, with the following opportunities:
  - At Primrose, the Company is currently drilling the first of two CSS pads which are targeted to come on production in Q2/25, and one SAGD pad at Wolf Lake which is targeted to come on production in Q1/25.
  - At Kirby, two of the four previously drilled SAGD pads have reached full production capacities, with the two remaining pads targeted to ramp up to their full production capacities in mid-2024.
  - At Jackfish, two SAGD pads that were drilled in 2023 are targeted to ramp up to their full production capacities in Q3/24 and Q4/24, supporting continued high utilization rates at the Jackfish facilities. 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 80% complete and the Company is targeting to begin solvent injection in mid-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			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Synthetic crude oil production (bbl/d) (1)(2)	**500,133**	490,853	428,784	**451,339**	425,945

(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 achieved record annual production of 451,339 bbl/d of high value SCO in 2023, an increase of 6% or approximately 25,400 bbl/d from 2022 levels. This increase is driven by the Company's focus on continuous improvement and increased reliability through safe, reliable, effective and efficient operations from its world class Oil Sands Mining and Upgrading assets.

- Oil Sands Mining and Upgrading operating costs are top tier, averaging $24.32/bbl (US$18.02/bbl) in 2023, a decrease of 7% from 2022 levels, primarily reflecting higher production volumes and lower energy costs.

▪ The Company's high value SCO, representing approximately 46% of the Company's total liquids volumes, captured an average price premium to WTI of US$2.03/bbl and strong annual realized SCO pricing of $100.06/bbl in 2023, generating significant free cash flow for the Company.

▪ As previously announced with the 2024 budget, the Company is targeting turnarounds at its Oil Sands Mining and Upgrading operations:
  - At the Athabasca Oil Sands Project ("AOSP"), there are two turnarounds planned at non-operated Scotford Upgrader, where it will operate at reduced rates.
    - The first turnaround was originally targeted for 10 days in April 2024. It has now been moved into March 2024 for a duration of 17 days which includes additional scope and is targeted to impact Q1/24 quarterly average production by approximately 10,000 bbl/d, the same volume as originally budgeted in Q2/24.
    - The second turnaround is targeted to begin in September 2024 for a duration of 49 days, as previously announced.
    - The total combined targeted annual impact to production remains unchanged from the budget at approximately 12,400 bbl/d.
  - At Horizon, a planned turnaround is targeted to occur in Q2/24 with a full plant outage targeted for approximately 30 days, impacting quarterly average production by approximately 89,000 bbl/d.

▪ The Company continues to pursue opportunities to increase production at both Horizon and at 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 at Horizon 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 at Horizon 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, during the 49 day turnaround in Q4/24, a debottlenecking project will be completed which targets to add incremental capacity at AOSP of approximately 5,600 bbl/d net to Canadian Natural.
  - At Horizon, the Company is progressing its 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 over the life of the Horizon project.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Crude oil production (bbl/d)	**25,829**	24,719	26,915	**26,091**	27,233
Natural gas production (MMcf/d)	**13**	12	10	**12**	15

▪ International E&P crude oil production volumes averaged 26,091 bbl/d in 2023, a decrease of 4% from 2022 levels, reflecting natural field declines.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) [1]	**$ 78.33**	$ 82.18	$ 82.62	**$ 77.61**	$ 94.23
WCS Heavy Differential from WTI (US$/bbl)	**$ 21.90**	$ 12.86	$ 25.65	**$ 18.62**	$ 18.26
WCS heavy differential as a percentage of WTI (%) [2]	**28%**	16%	31%	**24%**	19%
SCO benchmark price (US$/bbl)	**$ 78.64**	$ 84.99	$ 86.78	**$ 79.64**	$ 98.66
Condensate benchmark price (US$/bbl)	**$ 76.22**	$ 77.91	$ 83.33	**$ 76.55**	$ 93.69
Exploration & Production liquids realized pricing (C$/bbl) [3][4]	**$ 69.39**	$ 87.83	$ 69.34	**$ 72.36**	$ 90.64
SCO realized pricing (C$/bbl) [4][5]	**$ 98.73**	$ 108.55	$ 103.79	**$ 100.06**	$ 117.69
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.52**	$ 2.26	$ 5.29	**$ 2.77**	$ 5.28
Natural gas realized pricing (C$/Mcf) [5]	**$ 2.80**	$ 2.81	$ 6.39	**$ 3.10**	$ 6.55

(1) West Texas Intermediate ("WTI").

(2) Western Canadian Select ("WCS").

(3) Average crude oil and NGL pricing excludes SCO. Pricing is net of blending costs and excluding risk management activities.

(4) Non-GAAP ratio. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2023 dated February 28, 2024.

(5) Pricing is net of blending costs and excluding risk management activities.

- Canadian Natural has a balanced and diverse product mix of natural gas, NGLs, heavy crude oil, light crude oil, bitumen and SCO.
- WTI prices in 2023 were down 18% compared to 2022, reflecting concerns of higher non-OPEC supply and lower than anticipated global crude oil demand as a result of persistent inflation and the resulting increase in interest rates. Crude oil prices remain volatile as the global crude oil market continues to be impacted by heightened geopolitical tensions.
- SCO benchmark pricing averaged US$79.64/bbl in 2023, representing a US$2.03/bbl price premium to WTI in 2023, compared to a US$4.43/bbl price premium to WTI in 2022. SCO has traded at a premium to WTI in recent years as a result of strong North American demand for refined products; however, the lower price premium in 2023 relative to 2022 was driven by increased production and egress constraints in the Western Canadian Sedimentary Basin ("WCSB"), particularly in Q4/23.
- The WCS differential to WTI was US$18.62/bbl in 2023, comparable to US$18.26/bbl in 2022. As a percentage of WTI, the WCS differential widened to 24% in 2023 from 19% in 2022, primarily as a result of increased production and egress constraints in the WCSB.
- The North West Redwater ("NWR") refinery primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 81,525 bbl/d in 2023.
- Natural gas prices decreased in 2023, with AECO averaging $2.77/GJ in 2023 compared to $5.28/GJ in 2022, reflecting lower NYMEX benchmark pricing, increased production in the WCSB and lower storage draws due to decreased demand resulting from mild winter weather in 2023.
  - As a result of the Company's diversified sale points, average natural gas realized pricing of $3.10/Mcf was achieved in 2023, which was 15% above the average AECO benchmark price, maximizing value for shareholders. Approximately 26% of the Company's natural gas production was sold at AECO/Station 2 pricing, and approximately 37% was exported to other North American and international markets, capturing higher natural gas prices. Additionally, the Company used the equivalent of approximately 37% of its natural gas production in its operations in 2023.

- Canadian Natural has been a supporter of incremental pipeline projects to ensure Canadian crude oil and natural gas can access global markets to deliver the most responsible and leading ESG production that the world needs.
  - Canadian Natural has committed 94,000 bbl/d on Trans Mountain Corporation's ("Trans Mountain") 590,000 bbl/d Trans Mountain Expansion project ("TMX").
    - TMX is approximately 98% complete and is targeting to be in service in Q2/24.

FINANCIAL REVIEW

- Canadian Natural's financial positions remains strong, given its proven strategies including its disciplined approach to capital allocation. The Company's adjusted funds flow generation, credit facilities, US commercial paper program, access to capital markets, diverse asset base and flexible capital expenditure program all support a strong financial position and provide the appropriate financial resources for the near-, mid- and long-term.
- The Company's safe, effective and efficient operations combined with a high quality, long life low decline asset base generated annual free cash flow of approximately $6.9 billion in 2023 after dividend payments of $3.9 billion and base capital expenditures of $4.5 billion (excluding net acquisitions and strategic growth capital of $0.9 billion, as per the Company's free cash flow allocation policy in 2023).
- In 2023, the Company directly returned to shareholders approximately $7.2 billion through $3.9 billion in dividends and $3.3 billion through the repurchase and cancellation of approximately 40.1 million common shares.
  - In Q4/23, returns to shareholders were strong, totaling approximately $2.5 billion, comprised of $1.0 billion of dividends and $1.5 billion through the repurchase and cancellation of approximately 17.6 million common shares at a weighted average price of $88.26 per share.
- Canadian Natural continues to maintain a strong balance sheet and financial flexibility, with net debt of approximately $9.9 billion and significant liquidity of approximately $6.9 billion at the end of 2023.
  - Undrawn revolving bank credit facilities totaling approximately $5.5 billion were available at December 31, 2023. Including cash and cash equivalents and short-term investments, the Company had significant liquidity of approximately $6.9 billion. At December 31, 2023, 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.
  - In Q2/23, the Company extended its $2.425 billion revolving syndicated credit facility originally maturing June 2024 to June 2027.
  - In Q3/23, the Company extended its $0.5 billion revolving credit facility originally maturing February 2024 to February 2025.
  - In Q4/23, the Company repaid $0.405 billion of 1.45% medium-term notes.
- With the Company's net debt below $10 billion at year end 2023, the Company is now targeting in 2024 to return 100% of free cash flow to shareholders through dividends and share repurchases, per our free cash flow allocation policy. Going forward, the Company will manage this allocation of free cash flow on a forward looking annual basis, while managing working capital and cash management as required.

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 large 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 its 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, which will enhance the Company’s environmental performance and long-term sustainability.

Environmental Targets

Canadian Natural is committed to reducing its 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. The proposed carbon storage hub would be one of the world's largest carbon capture and storage projects and would be connected to a transportation line that would initially gather captured CO_2 from oil sands facilities in the Fort McMurray, Christina Lake and Cold Lake regions. Future phases of the plan have the potential to grow the transportation network to include over 20 oil sands facilities, and to accommodate other industries in the region interested in CCS.

Pathways continues to advance its proposed foundational carbon capture and storage project as it works with governments on the necessary co-investment and regulatory certainty needed to proceed. Work is ongoing to obtain a carbon sequestration agreement from the Government of Alberta to support regulatory applications for the proposed CO_2 transportation network and carbon storage hub, which are targeted for submission in the first half of 2024. 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. In November 2023, 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.

2023 YEAR END RESERVES

Determination of Reserves

For the year ended December 31, 2023, the Company retained IQREs, Sproule Associates Limited, Sproule International Limited and GLJ Ltd., to evaluate and review all of the Company's proved and proved plus probable reserves. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

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

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

Summary of Company Gross Reserves

As of December 31, 2023
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
Total Company								
Proved								
Developed Producing	114	106	203	653	6,827	4,730	138	8,829
Developed Non-Producing	5	7	—	38	—	229	7	95
Undeveloped	100	80	55	2,596	83	10,045	398	4,986
Total Proved	218	193	258	3,287	6,910	15,005	543	13,910
Probable	87	95	107	1,903	550	9,279	305	4,594
Total Proved plus Probable	305	288	365	5,191	7,460	24,284	848	18,504

Notes to Reserves:

1. Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
2. Information in the reserves data tables may not add due to rounding. BOE values and oil and natural gas metrics may not calculate exactly due to rounding.
3. Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserves estimates are the 3-Consultant-Average of price forecasts developed by Sproule Associates Limited, GLJ Ltd. and McDaniel & Associates Consultants Ltd., dated December 31, 2023:

		2024	2025	2026	2027	2028
Crude Oil and NGLs						
WTI	US$/bbl	73.67	74.98	76.14	77.66	79.22
WCS	C$/bbl	76.74	79.77	81.12	82.88	85.04
Canadian Light Sweet	C$/bbl	92.91	95.04	96.07	97.99	99.95
Cromer LSB	C$/bbl	93.57	95.86	96.46	98.39	100.36
Edmonton C5+	C$/bbl	96.79	98.75	100.71	102.72	104.78
Brent	US$/bbl	78.00	79.18	80.36	81.79	83.41
AECO	C$/MMBtu	2.20	3.37	4.05	4.13	4.21
BC Westcoast Station 2	C$/MMBtu	2.06	3.25	3.93	4.01	4.09
Henry Hub	US$/MMBtu	2.75	3.64	4.02	4.10	4.18

All prices increase at a rate of 2% per year after 2028.

A foreign exchange rate of 0.7517 US$/C$ was used for 2024 and 2025, and 0.7550 US$/C$ was used for 2026 and thereafter in the year end 2023 evaluation.

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

5. Oil and natural gas metrics included herein are commonly used in the crude oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural's performance over time. However, such measures are not reliable indicators of Canadian Natural's future performance and future performance may vary.
6. Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.
7. Reserves replacement or Production replacement ratio is the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.
8. Reserves Life Index ("RLI") is based on the amount for the relevant reserves category divided by the 2024 proved developed producing production forecast prepared by the IQREs.
9. Finding, Development and Acquisition ("FD&A") costs excluding changes in Future Development Costs ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2023 by the sum of total additions and revisions for the relevant reserves category.
10. FD&A costs including changes in FDC are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2023 and net changes in FDC from December 31, 2022 to December 31, 2023 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment, decommissioning and reclamation costs.
11. Abandonment, decommissioning and reclamation ("ADR") costs included in the calculation of the Future Net Revenue ("FNR") consist of both the Company's total Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as at December 31, 2023 and forecast estimates of ADR costs attributable to future development activity.

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Special Note Regarding Non-GAAP and Other Financial Measures

This press release 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 press release, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below as well as in the “Non-GAAP and Other Financial Measures” section of the Company's MD&A for the three months and year ended December 31, 2023, dated February 28, 2024.

Free Cash Flow

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 debt, pursuant to the free cash flow allocation policy.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Adjusted funds flow (1)	**$ 4,419**	$ 4,684	$ 4,176	**$ 15,274**	$ 19,791
Less: Base capital expenditures (2)	**$ 795**	$ 896	$ 766	**$ 3,958**	$ 3,621
Abandonment expenditures, net (3)	**$ 149**	$ 123	$ 84	**$ 509**	$ 335
Dividends on common shares	**$ 980**	$ 984	$ 834	**$ 3,891**	$ 4,926
Free cash flow	**$ 2,495**	$ 2,681	$ 2,492	**$ 6,917**	$ 10,909

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, which are provided in the “Non-GAAP and Other Financial Measures” section of the Company's MD&A for the three months and year ended December 31, 2023, dated February 28, 2024.

(2) Item is a component of net capital expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of Company's MD&A for the three months and year ended December 31, 2023, dated February 28, 2024 for more details on net capital expenditures.

(3) Non-GAAP Financial Measure. In prior reporting periods, abandonment expenditures was reported as part of base capital; however, in Q4/23, the Company revised the composition of its net capital expenditures non-GAAP financial measure to exclude expenditures related to the Company's abandonment program. A reconciliation of abandonment expenditures and abandonment expenditures, net is presented in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2023, dated February 28, 2024.

The Company's free cash flow allocation policy is applied based on the Company's net debt level as follows:

- In 2023, when net debt was between $10 billion and $15 billion, approximately 50% of free cash flow was allocated to shareholder returns and 50% was allocated to the balance sheet, less strategic growth / acquisition opportunities, with free cash flow calculated as adjusted funds flow less base capital expenditures, abandonment expenditures, and dividends on common shares.
- When net debt is at approximately $10 billion, the Company targets to return 100% of free cash flow to shareholders, with free cash flow calculated as adjusted funds flow less net capital expenditures, abandonment expenditures, and dividends on common shares. 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.

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.

Long-term Debt, net

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

($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022
Long-term debt	**$ 10,799**	$ 11,644	$ 11,445
Less: cash and cash equivalents	**877**	125	920
Long-term debt, net	**$ 9,922**	$ 11,519	$ 10,525

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.

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.

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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 expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital 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 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 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 and its subsidiaries to complete capital programs; the Company's and its subsidiaries' 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 and its subsidiaries' 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); 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; 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 and year ended December 31, 2023, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2022. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three months and year ended December 31, 2023 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 and year ended December 31, 2023 in relation to the comparable periods in 2022 and the third 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, 2022, 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 February 28, 2024.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Dec 31 2023	Sep 30 2023	Dec 31 2022	Year Ended Dec 31 2023	Dec 31 2022
Product sales [1]	**$ 10,679**	$ 11,762	$ 11,012	**$ 40,835**	$ 49,530
Crude oil and NGLs	**$ 9,829**	$ 10,944	$ 9,508	**$ 37,300**	$ 43,009
Natural gas	**$ 603**	$ 599	$ 1,287	**$ 2,575**	$ 5,236
Net earnings	**$ 2,627**	$ 2,344	$ 1,520	**$ 8,233**	$ 10,937
Per common share – basic	**$ 2.43**	$ 2.15	$ 1.37	**$ 7.54**	$ 9.64
– diluted	**$ 2.41**	$ 2.13	$ 1.36	**$ 7.47**	$ 9.52
Adjusted net earnings from operations [2]	**$ 2,546**	$ 2,850	$ 2,194	**$ 8,533**	$ 12,863
Per common share – basic [3]	**$ 2.36**	$ 2.61	$ 1.98	**$ 7.82**	$ 11.33
– diluted [3]	**$ 2.34**	$ 2.59	$ 1.96	**$ 7.74**	$ 11.19
Cash flows from operating activities	**$ 4,815**	$ 3,498	$ 4,544	**$ 12,353**	$ 19,391
Adjusted funds flow [2]	**$ 4,419**	$ 4,684	$ 4,176	**$ 15,274**	$ 19,791
Per common share – basic [3]	**$ 4.09**	$ 4.30	$ 3.78	**$ 14.00**	$ 17.44
– diluted [3]	**$ 4.05**	$ 4.26	$ 3.73	**$ 13.86**	$ 17.22
Cash flows used in investing activities	**$ 946**	$ 1,199	$ 1,262	**$ 4,858**	$ 4,987
Net capital expenditures [4]	**$ 975**	$ 1,108	$ 1,233	**$ 4,909**	$ 5,136
Abandonment expenditures, net [2]	**$ 149**	$ 123	$ 84	**$ 509**	$ 335

(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 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 year ended December 31, 2023 were $8,233 million compared with $10,937 million for the year ended December 31, 2022. Net earnings for the year ended December 31, 2023 included non-operating losses, net of tax, of $300 million compared with non-operating losses of $1,926 million for the year ended December 31, 2022 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on the settlement of the cross currency swap and repayment of US dollar debt securities, the gain from investments, a recoverability charge relating to the increase in estimate of future abandonment costs for the planned decommissioning activities at the Ninian field in the North Sea in 2023, a recoverability charge relating to the de-booking of reserves at the Ninian field in the North Sea in 2022, and government grant income under the provincial well-site rehabilitation programs in 2022. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2023 were $8,533 million compared with $12,863 million for the year ended December 31, 2022.

Net earnings for the fourth quarter of 2023 were $2,627 million compared with $1,520 million for the fourth quarter of 2022 and $2,344 million for the third quarter of 2023. Net earnings for the fourth quarter of 2023 included non-operating income, net of tax, of $81 million compared with non-operating losses of $674 million for the fourth quarter of 2022 and non-operating losses of $506 million for the third quarter of 2023 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of realized foreign exchange on the repayment of US dollar debt securities, the loss (gain) from investments, a recoverability charge relating to the increase in estimate of future abandonment costs for the planned decommissioning activities at the Ninian field in the North Sea in 2023, a recoverability charge relating to the de-booking of reserves at the Ninian field in the North Sea in 2022, and government grant income under the provincial well-site rehabilitation programs in 2022. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2023 were $2,546 million compared with $2,194 million for the fourth quarter of 2022 and $2,850 million for the third quarter of 2023.

The decrease in net earnings and adjusted net earnings from operations for the year ended December 31, 2023 from the year ended December 31, 2022 primarily reflected:

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

partially offset by:

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

The increase in net earnings and adjusted net earnings from operations for the fourth quarter of 2023 from the fourth quarter of 2022 primarily reflected:

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

partially offset by:

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

The movements in net earnings and adjusted net earnings from operations for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected:

- higher crude oil and NGLs sales volumes in the Exploration and Production segments; and
- higher natural gas sales volumes and netbacks in the North America Exploration and Production segment;

partially offset by:

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

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

Prevailing regulatory and economic conditions and the increasingly challenging commercial outlook in the United Kingdom, including the impact of higher natural gas and carbon costs, led the Company to assess the viability of its North Sea operations in 2022. Following a detailed review of its development plans, the Company determined that the Ninian field is no longer economic, de-booked crude oil reserves as at December 31, 2022 and is accelerating abandonment. As a result, the Company completed a recoverability assessment of its assets in the North Sea, and recognized a non-cash charge of $651 million (after-tax) related to the Ninian field property, plant and equipment, comprised of a recoverability charge of $1,620 million recognized in depletion, depreciation and amortization expense, net of deferred tax recoveries of $969 million.

As at December 31, 2023, as a result of revised project scope and the current cost environment, the Company recognized a non-cash charge of $113 million (after-tax) related to an increase in its estimate of the future abandonment costs for the Ninian field in the North Sea. The non-cash charge is comprised of a recoverability charge of $436 million recognized in depletion, depreciation and amortization expense, net of deferred tax recoveries of $323 million. The Company's estimate of its asset retirement obligation liability, including the Ninian field recoverability charge and associated tax recoveries, is subject to revision in future periods as abandonment efforts progress.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the year ended December 31, 2023 were $12,353 million compared with $19,391 million for the year ended December 31, 2022. Cash flows from operating activities for the fourth quarter of 2023 were $4,815 million compared with $4,544 million for the fourth quarter of 2022 and $3,498 million for the third 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.

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

Adjusted funds flow for the year ended December 31, 2023 was $15,274 million compared with $19,791 million for the year ended December 31, 2022. Adjusted funds flow for the fourth quarter of 2023 was $4,419 million compared with $4,176 million for the fourth quarter of 2022 and $4,684 million for the third 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, government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets, including the unamortized cost of the share bonus program, accrued interest on the deferred PRT recovery, and prepaid cost of service tolls.

Production Volumes

Record crude oil and NGLs production before royalties for the fourth quarter of 2023 of 1,047,541 bbl/d increased 11% from 942,258 bbl/d for the fourth quarter of 2022, and was comparable with 1,035,153 bbl/d for the third quarter of 2023. Record natural gas production before royalties for the fourth quarter of 2023 of 2,231 MMcf/d increased 5% from 2,115 MMcf/d for the fourth quarter of 2022, and increased 4% from 2,151 MMcf/d for the third quarter of 2023. Total production before royalties for the fourth quarter of 2023 of 1,419,313 BOE/d increased 10% from 1,294,679 BOE/d for the fourth quarter of 2022, and was comparable with 1,393,614 BOE/d for the third 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 averaged $69.39 per bbl for the fourth quarter of 2023, comparable with $69.34 per bbl for the fourth quarter of 2022, and a decrease of 21% from $87.83 per bbl for the third quarter of 2023. The realized natural gas price decreased 56% to average $2.80 per Mcf for the fourth quarter of 2023 from $6.39 per Mcf for the fourth quarter of 2022, and was comparable with $2.81 per Mcf for the third quarter of 2023. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price decreased 5% to average $98.73 per bbl for the fourth quarter of 2023 from $103.79 per bbl for the fourth quarter of 2022, and decreased 9% from $108.55 per bbl for the third 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.

Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense [1] averaged $15.05 per bbl for the fourth quarter of 2023, a decrease of 26% from $20.37 per bbl for the fourth quarter of 2022, and an increase of 5% from $14.40 per bbl for the third quarter of 2023. Natural gas production expense [1] averaged $1.13 per Mcf for the fourth quarter of 2023, a decrease of 10% from $1.25 per Mcf for the fourth quarter of 2022 and the third quarter of 2023. In the Oil Sands Mining and Upgrading segment, production expense [1] averaged $20.96 per bbl for the fourth quarter of 2023, a decrease of 18% from $25.48 per bbl for the fourth quarter of 2022, and a decrease of 5% from $22.12 per bbl for the third 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.

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

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

($ millions, except per common share amounts)	**Dec 31 2023**	Sep 30 2023	Jun 30 2023	Mar 31 2023
Product sales [(1)]	**$ 10,679**	$ 11,762	$ 8,846	$ 9,548
Crude oil and NGLs	**$ 9,829**	$ 10,944	$ 8,115	$ 8,412
Natural gas	**$ 603**	$ 599	$ 522	$ 851
Net earnings	**$ 2,627**	$ 2,344	$ 1,463	$ 1,799
Net earnings per common share				
– basic	**$ 2.43**	$ 2.15	$ 1.34	$ 1.63
– diluted	**$ 2.41**	$ 2.13	$ 1.32	$ 1.62

($ millions, except per common share amounts)	Dec 31 2022	Sep 30 2022	Jun 30 2022	Mar 31 2022
Product sales [(1)]	$ 11,012	$ 12,574	$ 13,812	$ 12,132
Crude oil and NGLs	$ 9,508	$ 11,001	$ 11,727	$ 10,773
Natural gas	$ 1,287	$ 1,342	$ 1,605	$ 1,002
Net earnings	$ 1,520	$ 2,814	$ 3,502	$ 3,101
Net earnings per common share				
– basic	$ 1.37	$ 2.52	$ 3.04	$ 2.66
– diluted	$ 1.36	$ 2.49	$ 3.00	$ 2.63

(1) Further details related to product sales for the three months ended December 31, 2023 and 2022 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 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.
- **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 and timing of acquisitions, and 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 relating to the increase in estimate of future abandonment costs for the planned decommissioning activities at the Ninian field in the North Sea in 2023, and a recoverability charge relating to the de-booking of reserves at the Ninian field in the North Sea at December 31, 2022.
- **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 Petroleum Revenue Tax ("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.
- **Loss (gain) from investment** – Fluctuations due to the loss (gain) from the investment in PrairieSky Royalty Ltd. shares.

BUSINESS ENVIRONMENT

Risks and Uncertainties

Rising interest rates in response to persistent inflation and concerns of a global recession put downward pressure on global crude oil benchmark pricing in 2023 and heightened geopolitical tensions led to pricing volatility throughout 2023. Higher non-OPEC supply and record US production in the fourth quarter of 2023 reduced the impact of previously announced OPEC+ production cuts. 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 December 31, 2023, 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 $6,852 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.

Capital Spending

On December 14, 2023, the Company announced its 2024 capital budget [(2)] targeted at approximately $5,420 million, and targets 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. Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns and the balancing of project risks and time horizons. The 2024 capital budget and targeted abandonment expenditures constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

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

(2) 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 this MD&A for more details on Net Capital Expenditures.

Benchmark Commodity Prices

	Three Months Ended			Year Ended	
(Average for the period)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
WTI benchmark price (US$/bbl)	**$ 78.33**	$ 82.18	$ 82.62	**$ 77.61**	$ 94.23
Dated Brent benchmark price (US$/bbl)	**$ 84.06**	$ 86.68	$ 88.15	**$ 82.61**	$ 99.80
WCS Heavy Differential from WTI (US$/bbl)	**$ 21.90**	$ 12.86	$ 25.65	**$ 18.62**	$ 18.26
SCO benchmark price (US$/bbl)	**$ 78.64**	$ 84.99	$ 86.78	**$ 79.64**	$ 98.66
Condensate benchmark price (US$/bbl)	**$ 76.22**	$ 77.91	$ 83.33	**$ 76.55**	$ 93.69
Condensate Differential from WTI (US$/bbl)	**$ 2.11**	$ 4.27	$ (0.71)	**$ 1.06**	$ 0.54
NYMEX benchmark price (US$/MMBtu)	**$ 2.87**	$ 2.55	$ 6.27	**$ 2.74**	$ 6.64
AECO benchmark price (C$/GJ)	**$ 2.52**	$ 2.26	$ 5.29	**$ 2.77**	$ 5.28
US/Canadian dollar average exchange rate (US$)	**$ 0.7341**	$ 0.7456	$ 0.7366	**$ 0.7409**	$ 0.7686

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$77.61 per bbl for the year ended December 31, 2023, a decrease of 18% from US$94.23 per bbl for the year ended December 31, 2022. WTI averaged US$78.33 per bbl for the fourth quarter of 2023, a decrease of 5% from US$82.62 per bbl for the fourth quarter of 2022, and a decrease of 5% from US$82.18 per bbl for the third 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$82.61 per bbl for the year ended December 31, 2023, a decrease of 17% from US$99.80 per bbl for the year ended December 31, 2022. Brent averaged US$84.06 per bbl for the fourth quarter of 2023, a decrease of 5% from US$88.15 per bbl for the fourth quarter of 2022, and a decrease of 3% from US$86.68 per bbl for the third quarter of 2023.

The decrease in WTI and Brent pricing for the three months and year ended December 31, 2023 from the comparable periods in 2022 primarily reflected concerns of higher non-OPEC supply and lower than anticipated global crude oil demand, as a result of persistent inflation and the resulting increase in interest rates. The decrease in WTI and Brent pricing for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected demand concerns and growing global supply.

The WCS Heavy Differential averaged US$18.62 per bbl for the year ended December 31, 2023, compared with US$18.26 per bbl for the year ended December 31, 2022. The WCS Heavy Differential averaged US$21.90 per bbl for the fourth quarter of 2023, compared with US$25.65 per bbl for the fourth quarter of 2022, and US$12.86 per bbl for the third quarter of 2023. The narrowing of the WCS Heavy Differential for the fourth quarter of 2023 from the fourth quarter of 2022 primarily reflected strengthening of US Gulf Coast heavy oil pricing in 2023 and a decrease in supply from the US Strategic Petroleum Reserve following releases in 2022. The widening of the WCS Heavy Differential for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected reduced refining capacity due to maintenance activities in the US, together with increased supply and egress constraints following fall production turnarounds.

The SCO benchmark price averaged US$79.64 per bbl for the year ended December 31, 2023, a decrease of 19% from US$98.66 per bbl for the year ended December 31, 2022. The SCO benchmark price averaged US$78.64 per bbl for the fourth quarter of 2023, a decrease of 9% from US$86.78 per bbl for the fourth quarter of 2022, and a decrease of 7% from US$84.99 per bbl for the third quarter of 2023. The decrease in SCO benchmark pricing for the three months and year ended December 31, 2023 from the comparable periods primarily reflected the decrease in WTI benchmark pricing, together with increased production and egress constraints in the Western Canadian Sedimentary Basin ("WCSB").

NYMEX natural gas prices averaged US$2.74 per MMBtu for the year ended December 31, 2023, a decrease of 59% from US$6.64 per MMBtu for the year ended December 31, 2022. NYMEX natural gas prices averaged US$2.87 per MMBtu for the fourth quarter of 2023, a decrease of 54% from US$6.27 per MMBtu for the fourth quarter of 2022, and an increase of 13% from US$2.55 per MMBtu for the third quarter of 2023. The decrease in NYMEX natural gas prices for the three months and year ended December 31, 2023 from the comparable periods in 2022 primarily reflected increased production and lower storage draws due to mild winter weather in 2023. Additionally, lower global Liquefied Natural Gas ("LNG") prices amid ample supply put downward pressure on NYMEX benchmark prices. The increase in NYMEX natural gas prices for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected seasonal demand factors as well as record LNG exports out of the US Gulf Coast.

AECO natural gas prices averaged $2.77 per GJ for the year ended December 31, 2023, a decrease of 48% from $5.28 per GJ for the year ended December 31, 2022. AECO natural gas prices averaged $2.52 per GJ for the fourth quarter of 2023, a decrease of 52% from $5.29 per GJ for the fourth quarter of 2022, and an increase of 12% from $2.26 per GJ for the third quarter of 2023. The decrease in AECO natural gas prices for the three months and year ended December 31, 2023 from the comparable periods in 2022 primarily reflected NYMEX benchmark pricing, increased production in the WCSB, and lower storage draws due to decreased demand resulting from mild winter weather in 2023. The increase in AECO natural gas prices for the fourth quarter of 2023 to the third quarter of 2023 reflected NYMEX benchmark pricing, seasonal demand factors and increased exports out of the WCSB.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**521,579**	519,581	486,559	**496,100**	479,971
North America – Oil Sands Mining and Upgrading (1)	**500,133**	490,853	428,784	**451,339**	425,945
International – Exploration and Production					
North Sea	**12,616**	12,016	14,006	**12,639**	12,890
Offshore Africa	**13,213**	12,703	12,909	**13,452**	14,343
Total International (2)	**25,829**	24,719	26,915	**26,091**	27,233
Total Crude oil and NGLs	**1,047,541**	1,035,153	942,258	**973,530**	933,149
Natural gas (MMcf/d) (3)					
North America	**2,218**	2,139	2,105	**2,139**	2,075
International					
North Sea	**2**	1	3	**2**	2
Offshore Africa	**11**	11	7	**10**	13
Total International	**13**	12	10	**12**	15
Total Natural gas	**2,231**	2,151	2,115	**2,151**	2,090
Total Barrels of oil equivalent (BOE/d)	**1,419,313**	1,393,614	1,294,679	**1,332,105**	1,281,434
Product mix					
Light and medium crude oil and NGLs	**10%**	10%	11%	**10%**	11%
Pelican Lake heavy crude oil	**3%**	3%	4%	**3%**	4%
Primary heavy crude oil	**6%**	5%	5%	**6%**	5%
Bitumen (thermal oil)	**20%**	21%	20%	**20%**	20%
Synthetic crude oil (1)	**35%**	35%	33%	**34%**	33%
Natural gas	**26%**	26%	27%	**27%**	27%
Percentage of product sales (1) (4) (5)					
Crude oil and NGLs	**94%**	95%	87%	**93%**	88%
Natural gas	**6%**	5%	13%	**7%**	12%

(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.
(3) Natural gas production volumes approximate sales volumes.
(4) Net of blending and feedstock costs and excluding risk management activities.
(5) Excluding Midstream and Refining revenue.

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**431,091**	409,479	381,546	**406,534**	374,089
North America – Oil Sands Mining and Upgrading	**443,535**	387,407	372,894	**385,996**	351,740
International – Exploration and Production					
North Sea	**12,590**	11,968	13,985	**12,609**	12,849
Offshore Africa	**11,917**	11,746	11,153	**12,183**	12,972
Total International	**24,507**	23,714	25,138	**24,792**	25,821
Total Crude oil and NGLs	**899,133**	820,600	779,578	**817,322**	751,650
Natural gas (MMcf/d)					
North America	**2,148**	2,068	1,937	**2,055**	1,885
International					
North Sea	**2**	1	3	**2**	2
Offshore Africa	**11**	10	6	**10**	11
Total International	**13**	11	9	**12**	13
Total Natural gas	**2,161**	2,079	1,946	**2,067**	1,898
Total Barrels of oil equivalent (BOE/d)	**1,259,297**	1,167,139	1,103,833	**1,161,852**	1,068,063

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.

Record crude oil and NGLs production before royalties for the year ended December 31, 2023 averaged 973,530 bbl/d, an increase of 4% from 933,149 bbl/d for the year ended December 31, 2022. Record crude oil and NGLs production for the fourth quarter of 2023 averaged 1,047,541 bbl/d, an increase of 11% from 942,258 bbl/d for the fourth quarter of 2022, and comparable with 1,035,153 bbl/d for the third quarter of 2023. The increase in crude oil and NGLs production before royalties for the three months and year ended December 31, 2023 from the comparable periods in 2022 primarily reflected stronger production in the Oil Sands Mining and Upgrading, and North America Exploration and Production segments in 2023 due to pad additions in thermal oil, drilling activity, and the impact of extreme cold weather conditions in the fourth quarter of 2022.

Annual crude oil and NGLs production for 2023 was within the Company's previously issued production target of 969,000 bbl/d to 1,001,000 bbl/d. 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.

Record natural gas production before royalties for the year ended December 31, 2023 averaged 2,151 MMcf/d, an increase of 3% from 2,090 MMcf/d for the year ended December 31, 2022. Record natural gas production for the fourth quarter of 2023 averaged 2,231 MMcf/d, an increase of 5% from 2,115 MMcf/d for the fourth quarter of 2022, and an increase of 4% from 2,151 MMcf/d for the third quarter of 2023. The increase in natural gas production before royalties for the year ended December 31, 2023 from the year ended December 31, 2022 primarily reflected 2023 drilling activity, partially offset by the impact of wildfires and a third party pipeline outage in 2023, together with natural field declines. The increase in natural gas production for the fourth quarter of 2023 from the comparable periods primarily reflected drilling activity, partially offset by natural field declines. The increase for the fourth quarter of 2023 from the fourth quarter of 2022 also reflected the impact of extreme cold weather conditions in the fourth quarter of 2022.

Annual natural gas production for 2023 was slightly below the Company's previously issued production target of 2,170 MMcf/d to 2,242 MMcf/d. 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 before royalties for the year ended December 31, 2023 averaged 496,100 bbl/d, an increase of 3% from 479,971 bbl/d for the year ended December 31, 2022. North America crude oil and NGLs production for the fourth quarter of 2023 of 521,579 bbl/d increased 7% from 486,559 bbl/d for the fourth quarter of 2022, and was comparable with 519,581 bbl/d for the third quarter of 2023. The increase in North America crude oil and NGLs production for the year ended December 31, 2023 from the year ended December 31, 2022 primarily reflected pad additions in thermal oil and conventional drilling activity in 2023, partially offset by the impacts of wildfires and a third party pipeline outage in 2023, and natural field declines. The increase for the fourth quarter of 2023 from the fourth quarter of 2022 primarily reflected pad additions in thermal oil, conventional drilling activity in 2023, and the impact of extreme cold weather conditions in the fourth quarter of 2022, partially offset by natural field declines.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 278,422 bbl/d for the fourth quarter of 2023, an increase of 10% from 253,188 bbl/d for the fourth quarter of 2022, and a decrease of 3% from 287,085 bbl/d for the third quarter of 2023. The increase in thermal oil production in the fourth quarter of 2023 from the fourth quarter of 2022 primarily reflected pad additions at Primrose and Kirby in 2023, partially offset by natural field declines. The decrease in thermal oil production in the fourth quarter of 2023 from the third quarter of 2023 primarily reflected the cyclical nature of steaming at Primrose and natural field declines.

Pelican Lake heavy crude oil production before royalties for the fourth quarter of 2023 averaged 46,046 bbl/d, a decrease of 5% from 48,221 bbl/d for the fourth quarter of 2022, and comparable with 46,897 bbl/d for the third quarter of 2023, demonstrating Pelican Lake's long life low decline production.

Natural gas production before royalties for the year ended December 31, 2023 averaged 2,139 MMcf/d, an increase of 3% from 2,075 MMcf/d for the year ended December 31, 2022. Natural gas production for the fourth quarter of 2023 averaged 2,218 MMcf/d, an increase of 5% from 2,105 MMcf/d for the fourth quarter of 2022, and an increase of 4% from 2,139 MMcf/d for the third quarter of 2023. The increase in natural gas production for the year ended December 31, 2023 from the year ended December 31, 2022 primarily reflected 2023 drilling activity, partially offset by the impact of wildfires and a third party pipeline outage in 2023, together with natural field declines. The increase in natural gas production for the fourth quarter of 2023 from the comparable periods primarily reflected drilling activity, partially offset by natural field declines. The increase for the fourth quarter of 2023 from the fourth quarter of 2022 also reflected the impact of extreme cold weather conditions in the fourth quarter of 2022.

North America – Oil Sands Mining and Upgrading

Record SCO production before royalties for the year ended December 31, 2023 averaged 451,339 bbl/d, an increase of 6% from 425,945 bbl/d for the year ended December 31, 2022. Record SCO production for the fourth quarter of 2023 averaged 500,133 bbl/d, an increase of 17% from 428,784 bbl/d for the fourth quarter of 2022, and comparable with 490,853 bbl/d for the third quarter of 2023. The increase in SCO production for the year ended December 31, 2023 from the year ended December 31, 2022 primarily reflected stronger production in 2023 following the impact of an extended turnaround at the non-operated Scotford Upgrader in the first half of 2022, an unplanned outage at Horizon and extreme cold weather conditions impacting mining operations in the fourth quarter of 2022. The increase for the fourth quarter of 2023 compared to the fourth quarter of 2022 primarily reflected stronger production in the fourth quarter of 2023 following an unplanned outage at Horizon and extreme cold weather conditions impacting mining operations in the fourth quarter of 2022.

International – Exploration and Production

International crude oil and NGLs production before royalties for the year ended December 31, 2023 averaged 26,091 bbl/d, a decrease of 4% from 27,233 bbl/d for the year ended December 31, 2022. International crude oil and NGLs production for the fourth quarter of 2023 averaged 25,829 bbl/d, a decrease of 4% from 26,915 bbl/d for the fourth quarter of 2022, and an increase of 4% from 24,719 bbl/d for the third quarter of 2023. The decrease in crude oil and NGLs production for the three months and year ended December 31, 2023 from the comparable periods in 2022 primarily reflected natural field declines. The increase in crude oil and NGLs production for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected planned maintenance activities in the third quarter, partially offset by natural field declines.

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)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022
International	**515,543**	1,167,250	390,959

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Crude oil and NGLs ($/bbl) (1)					
Realized price (2)	**$ 69.39**	$ 87.83	$ 69.34	**$ 72.36**	$ 90.64
Transportation (2)	**3.83**	4.07	4.11	**4.23**	4.13
Realized price, net of transportation (2)	**65.56**	83.76	65.23	**68.13**	86.51
Royalties (3)	**11.38**	17.32	13.56	**12.55**	18.91
Production expense (4)	**15.05**	14.40	20.37	**16.12**	18.17
Netback (2)	**$ 39.13**	$ 52.04	$ 31.30	**$ 39.46**	$ 49.43
Natural gas ($/Mcf) (1)					
Realized price (5)	**$ 2.80**	$ 2.81	$ 6.39	**$ 3.10**	$ 6.55
Transportation (6)	**0.54**	0.56	0.55	**0.56**	0.51
Realized price, net of transportation	**2.26**	2.25	5.84	**2.54**	6.04
Royalties (3)	**0.09**	0.09	0.51	**0.13**	0.61
Production expense (4)	**1.13**	1.25	1.25	**1.30**	1.22
Netback	**$ 1.04**	$ 0.91	$ 4.08	**$ 1.11**	$ 4.21
Barrels of oil equivalent ($/BOE) (1)					
Realized price (2)	**$ 48.41**	$ 59.40	$ 56.83	**$ 50.54**	$ 70.07
Transportation (2)	**3.61**	3.78	3.80	**3.88**	3.72
Realized price, net of transportation (2)	**44.80**	55.62	53.03	**46.66**	66.35
Royalties (3)	**7.05**	10.61	9.31	**7.77**	12.75
Production expense (4)	**11.75**	11.64	15.17	**12.74**	13.76
Netback (2)	**$ 26.00**	$ 33.37	$ 28.55	**$ 26.15**	$ 39.84

(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			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Crude oil and NGLs ($/bbl) (1)					
North America (2)	**$ 66.69**	$ 86.77	$ 65.79	**$ 70.51**	$ 88.43
International average (3)	**$ 112.22**	$ 113.59	$ 118.44	**$ 107.46**	$ 128.41
North Sea (3)	**$ 118.50**	$ 108.22	$ 118.91	**$ 110.99**	$ 129.04
Offshore Africa (3)	**$ 107.88**	$ 118.09	$ 117.74	**$ 106.25**	$ 127.85
Crude oil and NGLs average (2)	**$ 69.39**	$ 87.83	$ 69.34	**$ 72.36**	$ 90.64
Natural gas ($/Mcf) (1) (3)					
North America	**$ 2.75**	$ 2.76	$ 6.36	**$ 3.04**	$ 6.51
International average	**$ 12.15**	$ 12.21	$ 13.70	**$ 12.81**	$ 12.78
North Sea	**$ 9.66**	$ 9.99	$ 13.51	**$ 10.45**	$ 15.75
Offshore Africa	**$ 12.51**	$ 12.44	$ 13.80	**$ 13.19**	$ 12.23
Natural gas average	**$ 2.80**	$ 2.81	$ 6.39	**$ 3.10**	$ 6.55
Average ($/BOE) (1) (2)	**$ 48.41**	$ 59.40	$ 56.83	**$ 50.54**	$ 70.07

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

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

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

North America

North America realized crude oil and NGLs prices decreased 20% to average $70.51 per bbl for the year ended December 31, 2023 from $88.43 per bbl for the year ended December 31, 2022. North America realized crude oil and NGLs prices averaged $66.69 per bbl for the fourth quarter of 2023, comparable with $65.79 per bbl for the fourth quarter of 2022, and decreased 23% from $86.77 per bbl for the third quarter of 2023. The decrease for the year ended December 31, 2023 from year ended December 31, 2022 primarily reflected lower WTI benchmark pricing. The decrease for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected lower WTI benchmark pricing, combined with the widening of the WCS Heavy Differential. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2023 contributed approximately 228,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 53% to average $3.04 per Mcf for the year ended December 31, 2023 from $6.51 per Mcf for the year ended December 31, 2022. North America realized natural gas prices decreased 57% to average $2.75 per Mcf for the fourth quarter of 2023 from $6.36 per Mcf for the fourth quarter of 2022, and was comparable with $2.76 per Mcf for the third quarter of 2023. The decrease in North America realized natural gas prices for the three months and year ended December 31, 2023 from the comparable periods in 2022 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)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022
Wellhead Price (1)			
Light and medium crude oil and NGLs ($/bbl)	**$ 69.42**	$ 72.07	$ 77.08
Pelican Lake heavy crude oil ($/bbl)	**$ 73.47**	$ 93.19	$ 73.25
Primary heavy crude oil ($/bbl)	**$ 72.90**	$ 93.80	$ 69.20
Bitumen (thermal oil) ($/bbl)	**$ 62.64**	$ 89.50	$ 58.13
Natural gas ($/Mcf)	**$ 2.75**	$ 2.76	$ 6.36

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

International

International realized crude oil and NGLs prices decreased 16% to average $107.46 per bbl for the year ended December 31, 2023 from $128.41 per bbl for the year ended December 31, 2022. International realized crude oil and NGLs prices decreased 5% to average $112.22 per bbl for the fourth quarter of 2023 from $118.44 per bbl for the fourth quarter of 2022, and was comparable with $113.59 per bbl for the third 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 three months and year ended December 31, 2023 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			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 11.72**	$ 17.79	$ 14.07	**$ 12.89**	$ 19.64
International average	**$ 5.83**	$ 5.67	$ 6.56	**$ 5.99**	$ 6.38
North Sea	**$ 0.24**	$ 0.42	$ 0.18	**$ 0.33**	$ 0.30
Offshore Africa	**$ 10.58**	$ 8.90	$ 16.02	**$ 10.08**	$ 11.79
Crude oil and NGLs average	**$ 11.38**	$ 17.32	$ 13.56	**$ 12.55**	$ 18.91
Natural gas ($/Mcf) (1)					
North America	**$ 0.09**	$ 0.09	$ 0.51	**$ 0.13**	$ 0.61
Offshore Africa	**$ 0.59**	$ 0.59	$ 0.71	**$ 0.62**	$ 1.50
Natural gas average	**$ 0.09**	$ 0.09	$ 0.51	**$ 0.13**	$ 0.61
Average ($/BOE) (1)	**$ 7.05**	$ 10.61	$ 9.31	**$ 7.77**	$ 12.75

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

North America

North America crude oil and NGLs and natural gas royalties for the three months and year ended December 31, 2023 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 year ended December 31, 2023 compared with 22% of product sales for the year ended December 31, 2022. Crude oil and NGLs royalty rates averaged approximately 18% of product sales for the fourth quarter of 2023 compared with 21% for the fourth quarter of 2022 and 21% for the third quarter of 2023. The decrease in royalty rates for the three months and year ended December 31, 2023 from the comparable periods was primarily due to lower benchmark prices and fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 4% of product sales for the year ended December 31, 2023 compared with 9% of product sales for the year ended December 31, 2022. Natural gas royalty rates averaged approximately 3% of product sales for the fourth quarter of 2023 compared with 8% for the fourth quarter of 2022, and 3% for the third quarter of 2023. The decrease in royalty rates for the three months and year ended December 31, 2023 from the comparable periods in 2022 was primarily due to lower benchmark prices.

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

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 9% for the year ended December 31, 2023, comparable with 9% of product sales for the year ended December 31, 2022. Royalty rates as a percentage of product sales averaged approximately 9% for the fourth quarter of 2023 compared with 13% of product sales for the fourth quarter of 2022, and 7% for the third 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.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2023	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 12.56**	$ 13.21	$ 16.80	**$ 14.46**	$ 16.25
International average	**$ 54.95**	$ 44.16	$ 69.70	**$ 48.16**	$ 51.01
North Sea	**$ 92.28**	$ 83.44	$ 100.30	**$ 85.57**	$ 88.99
Offshore Africa	**$ 23.25**	$ 20.04	$ 24.30	**$ 21.14**	$ 17.25
Crude oil and NGLs average	**$ 15.05**	$ 14.40	$ 20.37	**$ 16.12**	$ 18.17
Natural gas ($/Mcf) (1)					
North America	**$ 1.09**	$ 1.22	$ 1.22	**$ 1.27**	$ 1.19
International average	**$ 8.76**	$ 7.40	$ 8.07	**$ 7.26**	$ 5.16
North Sea	**$ 9.52**	$ 9.19	$ 10.38	**$ 9.85**	$ 9.27
Offshore Africa	**$ 8.65**	$ 7.21	$ 6.98	**$ 6.83**	$ 4.40
Natural gas average	**$ 1.13**	$ 1.25	$ 1.25	**$ 1.30**	$ 1.22
Average ($/BOE) (1)	**$ 11.75**	$ 11.64	$ 15.17	**$ 12.74**	$ 13.76

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

North America

North America crude oil and NGLs production expense for the year ended December 31, 2023 averaged $14.46 per bbl, a decrease of 11% from $16.25 per bbl for the year ended December 31, 2022. North America crude oil and NGLs production expense for the fourth quarter of 2023 of $12.56 per bbl decreased 25% from $16.80 per bbl for the fourth quarter of 2022, and decreased 5% from $13.21 per bbl for the third quarter of 2023. The decrease in crude oil and NGLs production expense per bbl for the year ended December 31, 2023 from year ended December 31, 2022 primarily reflected lower energy costs, partially offset by higher service costs. The decrease in crude oil and NGLs production expense per bbl for the fourth quarter of 2023 to the fourth quarter of 2022 primarily reflected lower energy costs and higher production volumes. The decrease in crude oil and NGLs production expense per bbl for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected lower energy costs.

North America natural gas production expense averaged $1.27 per Mcf for the year ended December 31, 2023, an increase of 7% from $1.19 per Mcf for the year ended December 31, 2022. North America natural gas production expense for the fourth quarter of 2023 averaged $1.09 per Mcf, a decrease of 11% from $1.22 per Mcf for the fourth quarter of 2022 and for the third quarter of 2023. The increase in natural gas production expense per Mcf for the year ended December 31, 2023 from the year ended December 31, 2022 primarily reflected higher service costs. The decrease in natural gas production expense per Mcf for the fourth quarter of 2023 from the fourth quarter of 2022 was primarily due to lower power costs and higher production volumes, together with the impact of extreme cold weather conditions in the fourth quarter of 2022. The decrease from the third quarter of 2023 primarily reflected higher production volumes and lower energy costs.

International

International crude oil and NGLs production expense for the year ended December 31, 2023 averaged $48.16 per bbl, a decrease of 6% from $51.01 per bbl for the year ended December 31, 2022. International crude oil and NGLs production expense for the fourth quarter of 2023 of $54.95 per bbl decreased 21% from $69.70 per bbl for the fourth quarter of 2022, and increased 24% from $44.16 per bbl for the third quarter of 2023. The decrease in crude oil and NGLs production expense per bbl for the three months and year ended December 31, 2023 from the comparable periods in 2022 primarily reflected lower energy costs and the timing of liftings from various fields that have different cost structures. The increase in crude oil and NGLs production expense per bbl for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected 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 **Dec 31 2023**	Three Months Ended Sep 30 2023	Three Months Ended Dec 31 2022	Year Ended **Dec 31 2023**	Year Ended Dec 31 2022
North America	**$ 971**	$ 947	$ 949	**$ 3,679**	$ 3,595
North Sea	**466**	12	1,653	**494**	1,747
Offshore Africa	**66**	47	41	**213**	173
Depletion, depreciation and amortization	**$ 1,503**	$ 1,006	$ 2,643	**$ 4,386**	$ 5,515
Less: Recoverability charge (1) (2)	**436**	—	1,620	**436**	1,620
Adjusted depletion, depreciation and amortization (3)	**$ 1,067**	$ 1,006	$ 1,023	**$ 3,950**	$ 3,895
$/BOE (4)	**$ 12.46**	$ 12.22	$ 12.78	**$ 12.27**	$ 12.45

(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) Prevailing regulatory and economic conditions and the increasingly challenging commercial outlook in the United Kingdom, including the impact of higher natural gas and carbon costs, led the Company to assess the viability of its North Sea operations in 2022. As at December 31, 2022 the Company completed a recoverability assessment of its assets in the North Sea, and recognized a recoverability charge of $1,620 million in depletion, depreciation, and amortization expense following a detailed assessment which determined that the Ninian field was no longer economic.

(3) 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.

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

Adjusted depletion, depreciation and amortization expense for the year ended December 31, 2023 averaged $12.27 per BOE, comparable with $12.45 per BOE for the year ended December 31, 2022. Adjusted depletion, depreciation and amortization expense for the fourth quarter of 2023 averaged $12.46 per BOE, comparable with $12.78 per BOE for the fourth quarter of 2022, and $12.22 per BOE for the third quarter of 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 Dec 31 2023	Sep 30 2023	Dec 31 2022	Year Ended Dec 31 2023	Dec 31 2022
North America	**$ 58**	$ 59	$ 51	**$ 234**	$ 171
North Sea	**12**	11	10	**46**	33
Offshore Africa	**2**	2	2	**8**	7
Asset retirement obligation accretion	**$ 72**	$ 72	$ 63	**$ 288**	$ 211
$/BOE (1)	**$ 0.84**	$ 0.87	$ 0.78	**$ 0.89**	$ 0.67

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2023 of $0.89 per BOE increased 33% from $0.67 per BOE for the year ended December 31, 2022. Asset retirement obligation accretion expense for the fourth quarter of 2023 of $0.84 per BOE increased 8% from $0.78 per BOE for the fourth quarter of 2022, and decreased 3% from $0.87 per BOE for the third quarter of 2023. The increase in asset retirement obligation accretion expense per BOE for the three months and year ended December 31, 2023 from the comparable periods in 2022 primarily reflected the impact of cost, inflation and timing estimates, regulatory changes, and discount rate revisions made to the asset retirement obligation during 2022, partially offset by higher sales volumes in 2023. The decrease in asset retirement obligation accretion expense per BOE for the fourth quarter of 2023 from the third quarter of 2023 reflected higher sales volumes.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable, and efficient operations leveraging its technical expertise across the Horizon and AOSP sites with record SCO production averaging 500,133 bbl/d in the fourth quarter of 2023.

The Company incurred production expense of $947 million for the fourth quarter of 2023, a decrease of 7% from $1,017 million for the fourth quarter of 2022, and a decrease of 6% from $1,003 million for the third quarter of 2023, reflecting the Company's continued focus on cost control and efficiencies across the entire asset base.

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

($/bbl)	Three Months Ended Dec 31 2023	Sep 30 2023	Dec 31 2022	Year Ended Dec 31 2023	Dec 31 2022
Realized SCO sales price (1)	**$ 98.73**	$ 108.55	$ 103.79	**$ 100.06**	$ 117.69
Bitumen value for royalty purposes (2)	**$ 61.73**	$ 84.66	$ 58.24	**$ 65.43**	$ 83.07
Bitumen royalties (3)	**$ 11.57**	$ 21.90	$ 14.48	**$ 14.43**	$ 20.71
Transportation (1)	**$ 1.85**	$ 2.18	$ 1.80	**$ 1.89**	$ 1.71

(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 $100.06 per bbl for the year ended December 31, 2023, a decrease of 15% from $117.69 per bbl for the year ended December 31, 2022. The realized SCO sales price averaged $98.73 per bbl for the fourth quarter of 2023, a decrease of 5% from $103.79 per bbl for the fourth quarter of 2022, and a decrease of 9% from $108.55 per bbl for the third quarter of 2023. The decrease in the realized SCO sales price for the three months and year ended December 31, 2023 from the comparable periods in 2022 primarily reflected the decrease in WTI benchmark pricing. The decrease in realized SCO sales price for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected WTI benchmark pricing, together with increased production and egress constraints in the WCSB.

The decrease in bitumen royalties per bbl for the year ended December 31, 2023 from the year ended December 31, 2022 primarily reflected the impact of lower prevailing bitumen pricing and the impact of sliding scale royalty rates. The decrease in bitumen royalties per bbl for the fourth quarter of 2023 from the fourth quarter of 2022 primarily reflected sliding scale royalty rates. The decrease for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected lower prevailing bitumen pricing and the impact of sliding scale royalty rates.

Transportation expense averaged $1.89 per bbl for the year ended December 31, 2023, an increase of 11% from $1.71 per bbl for the year ended December 31, 2022. Transportation expense averaged $1.85 per bbl for the fourth quarter of 2023, an increase of 3% from $1.80 per bbl for the fourth quarter of 2022, and a decrease of 15% from $2.18 per bbl for the third quarter of 2023. The increase in transportation expense per bbl for the three months and year ended December 31, 2023 from the comparable periods in 2022 primarily reflected higher sales to the US Gulf Coast in 2023. The decrease for fourth quarter of 2023 from the third quarter of 2023 primarily reflected lower sales to the US Gulf Coast.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production expense disclosed in note 17 to the financial statements.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Production expense, excluding natural gas costs	**$ 904**	$ 962	$ 933	**$ 3,794**	$ 3,743
Natural gas costs	**43**	41	84	**195**	333
Production expense	**$ 947**	$ 1,003	$ 1,017	**$ 3,989**	$ 4,076

	Three Months Ended			Year Ended	
($/bbl)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Production expense, excluding natural gas costs (1)	**$ 20.00**	$ 21.22	$ 23.37	**$ 23.13**	$ 23.91
Natural gas costs (2)	**0.96**	0.90	2.11	**1.19**	2.13
Production expense (3)	**$ 20.96**	$ 22.12	$ 25.48	**$ 24.32**	$ 26.04
Sales volumes (bbl/d)	**491,339**	492,926	433,731	**449,282**	428,820

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

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

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

Production expense for the year ended December 31, 2023 averaged $24.32 per bbl, a decrease of 7% from $26.04 per bbl for the year ended December 31, 2022. Production expense for the fourth quarter of 2023 averaged $20.96 per bbl, a decrease of 18% from $25.48 per bbl for the fourth quarter of 2022, and a decrease of 5% from $22.12 per bbl for the third quarter of 2023. The decrease in production expense per bbl for the three months and year ended December 31, 2023 from the comparable periods in 2022 primarily reflected higher production volumes and lower energy costs. The decrease in production expense per bbl for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected lower energy costs.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Depletion, depreciation and amortization	**$ 554**	$ 527	$ 481	**$ 2,011**	$ 1,822
$/bbl (1)	**$ 12.25**	$ 11.62	$ 12.07	**$ 12.26**	$ 11.64

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

Depletion, depreciation and amortization expense for the year ended December 31, 2023 of $12.26 per bbl increased 5% from $11.64 per bbl for the year ended December 31, 2022. Depletion, depreciation and amortization expense for the fourth quarter of 2023 of $12.25 per bbl was comparable with $12.07 per bbl for the fourth quarter of 2022, and increased 5% from $11.62 per bbl for the third quarter of 2023. The increase in depletion, depreciation and amortization expense on a per bbl basis for the year ended December 31, 2023 from the comparable period in 2022 primarily reflected the impact of a higher depletable base due to asset additions, partially offset by higher sales volumes in 2023. The increase in depletion, depreciation and amortization expense on a per bbl basis for the fourth quarter of 2023 from the third quarter of 2023 primarily reflected a higher depletable base due to asset additions.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Asset retirement obligation accretion	**$ 19**	$ 20	$ 19	**$ 78**	$ 70
$/bbl [(1)]	**$ 0.43**	$ 0.43	$ 0.49	**$ 0.48**	$ 0.45

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2023 of $0.48 per bbl increased 7% from $0.45 per bbl for the year ended December 31, 2022. Asset retirement obligation accretion expense for the fourth quarter of 2023 of $0.43 per bbl decreased 12% from $0.49 per bbl for the fourth quarter of 2022, and was comparable with $0.43 per bbl for the third quarter of 2023. The increase in asset retirement obligation accretion expense on a per bbl basis for the year ended December 31, 2023 from the comparable period in 2022 primarily reflected the impact of cost, inflation and timing estimates, and discount rate revisions made to the asset retirement obligation during 2022, partially offset by higher sales volumes in 2023. The decrease in asset retirement obligation accretion expense on a per bbl basis for the fourth quarter of 2023 from the fourth quarter of 2022 primarily reflected the impact of higher sales volumes in the fourth quarter of 2023.

MIDSTREAM AND REFINING

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Product sales					
Midstream activities	**$ 20**	$ 20	$ 21	**$ 76**	$ 80
NWRP, refined product sales and other	**236**	237	205	**926**	906
Segmented revenue	**256**	257	226	**1,002**	986
Less:					
NWRP, refining toll	**82**	66	57	**303**	247
Midstream activities	**7**	8	6	**29**	24
Production expense	**89**	74	63	**332**	271
NWRP, transportation and feedstock costs	**166**	183	155	**664**	691
Depreciation	**4**	4	5	**16**	16
Segmented (loss) earnings	**$ (3)**	$ (4)	$ 3	**$ (10)**	$ 8

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 fourth quarter of 2023, production of ultra-low sulphur diesel and other refined products averaged 83,294 BOE/d (20,824 BOE/d to the Company), (three months ended September 30, 2023 – 78,376 BOE/d; 19,594 BOE/d to the Company; three months ended December 31, 2022 – 54,593 BOE/d; 13,648 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at December 31, 2023, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $555 million (December 31, 2022 – $551 million). For the three months ended December 31, 2023, the Company's unrecognized share of the equity loss was $5 million (year ended December 31, 2023 – unrecognized equity loss of $4 million; three months ended December 31, 2022 – recovery of unrecognized equity losses of $37 million; year ended December 31, 2022 – recovery of unrecognized equity losses of $11 million).

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Administration expense	**$ 119**	$ 108	$ 108	**$ 452**	$ 415
$/BOE (1)	**$ 0.91**	$ 0.84	$ 0.90	**$ 0.93**	$ 0.88
Sales volumes (BOE/d) (2)	**1,422,198**	1,388,033	1,303,996	**1,331,092**	1,285,877

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

(2) Total Company sales volumes.

Administration expense for the year ended December 31, 2023 of $0.93 per BOE increased 6% from $0.88 per BOE for the year ended December 31, 2022. Administration expense for the fourth quarter of 2023 of $0.91 per BOE was comparable with $0.90 per BOE for the fourth quarter of 2022, and increased 8% from $0.84 per BOE for the third quarter of 2023. The increase in administration expense per BOE for the three months and year ended December 31, 2023 from the comparable periods primarily reflected higher personnel and corporate costs, partially offset by higher sales volumes and higher overhead recoveries.

SHARE-BASED COMPENSATION

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Stock-based compensation expense	**$ 57**	$ 298	$ 319	**$ 491**	$ 804

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 $491 million of share-based compensation expense for the year ended December 31, 2023, 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			Year Ended	
($ millions, except effective interest rate)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Interest and other financing expense	**$ 117**	$ 187	$ 76	**$ 636**	$ 549
Less: Interest income and other (1)	**(53)**	4	(93)	**(55)**	(121)
Interest expense on long-term debt and lease liabilities (1)	**$ 170**	$ 183	$ 169	**$ 691**	$ 670
Average current and long-term debt (2)	**$ 12,350**	$ 13,393	$ 13,174	**$ 12,749**	$ 13,986
Average lease liabilities (2)	**1,484**	1,490	1,508	**1,500**	1,531
Average long-term debt and lease liabilities (2)	**$ 13,834**	$ 14,883	$ 14,682	**$ 14,249**	$ 15,517
Average effective interest rate (3) (4)	**4.8%**	4.8%	4.5%	**4.8%**	4.3%
Interest and other financing expense per $/BOE (5)	**$ 0.90**	$ 1.46	$ 0.63	**$ 1.31**	$ 1.17
Sales volumes (BOE/d) (6)	**1,422,198**	1,388,033	1,303,996	**1,331,092**	1,285,877

(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 year ended December 31, 2023 of $1.31 per BOE increased 12% from $1.17 per BOE for the year ended December 31, 2022. Interest and other financing expense per BOE for the fourth quarter of 2023 increased 43% to $0.90 per BOE from $0.63 per BOE for the fourth quarter of 2022, and decreased 38% from $1.46 per BOE for the third quarter of 2023. The increase in interest and other financing expense per BOE for the three months and year ended December 31, 2023 from the comparable periods in 2022 primarily reflected the impact of higher interest rates on floating rate long-term debt, together with the impact of higher accrued interest income on the deferred PRT recovery in 2022, partially offset by lower average debt levels in 2023. The decrease for the fourth quarter of 2023 from the third quarter of 2023 reflected accrued interest on deferred PRT, combined with lower average debt levels and higher sales volumes in the fourth quarter.

The Company's average effective interest rate for the three months and year ended December 31, 2023 increased from the comparable periods in 2022 primarily due to higher prevailing interest rates on floating rate long-term debt held during 2023.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Foreign currency contracts	**$ (15)**	$ 30	$ 3	**$ (17)**	$ (37)
Natural gas financial instruments (1) (2)	**(2)**	(1)	(6)	**3**	13
Crude oil and NGLs financial instruments (1)	**—**	—	1	**—**	17
Net realized (gain) loss	**(17)**	29	(2)	**(14)**	(7)
Foreign currency contracts	**(16)**	2	(2)	**(9)**	(16)
Natural gas financial instruments (1) (2)	**9**	1	18	**21**	(10)
Crude oil and NGLs financial instruments (1)	**—**	—	(1)	**—**	(2)
Net unrealized (gain) loss	**(7)**	3	15	**12**	(28)
Net (gain) loss	**$ (24)**	$ 32	$ 13	**$ (2)**	$ (35)

(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 year ended December 31, 2023, net realized risk management gains were related to the settlement of foreign currency contracts, partially offset by realized losses on the settlement of natural gas financial instruments. The Company recorded a net unrealized loss of $12 million ($7 million after-tax of $5 million) on its risk management activities for the year ended December 31, 2023, including a net unrealized gain of $7 million ($9 million after-tax of $2 million) for the fourth quarter of 2023 (three months ended September 30, 2023 – unrealized loss of $3 million, $2 million after-tax of $1 million; three months ended December 31, 2022 – unrealized loss of $15 million, $11 million after-tax of $4 million; year ended December 31, 2022 – unrealized gain of $28 million, $25 million after-tax of $3 million).

Further details related to outstanding derivative financial instruments as at December 31, 2023 are disclosed in note 15 to the financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Net realized loss (gain)	**$ 11**	$ (48)	$ 18	**$ (19)**	$ (114)
Net unrealized (gain) loss	**(276)**	250	(203)	**(260)**	852
Net (gain) loss (1)	**$ (265)**	$ 202	$ (185)	**$ (279)**	$ 738

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

The net realized foreign exchange gain for the year ended December 31, 2023 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 gain for the year ended December 31, 2023 was primarily related to the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at December 31, 2023 was US$0.7573 (September 30, 2023 – US$0.7387, December 31, 2022 – US$0.7389).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended **Dec 31 2023**	Sep 30 2023	Dec 31 2022	Year Ended **Dec 31 2023**	Dec 31 2022
North America [1]	**$ 487**	$ 587	$ 345	**$ 1,853**	$ 2,789
North Sea	**3**	(11)	33	**(6)**	69
Offshore Africa	**20**	23	23	**73**	74
Current PRT – North Sea	**(13)**	—	(5)	**(58)**	(42)
Other taxes	**8**	3	3	**17**	16
Current income tax	**505**	602	399	**1,879**	2,906
Deferred corporate income tax	**64**	195	(148)	**267**	302
Deferred PRT – North Sea	**(238)**	6	(441)	**(214)**	(441)
Deferred income tax	**(174)**	201	(589)	**53**	(139)
Income tax	**$ 331**	$ 803	$ (190)	**$ 1,932**	$ 2,767
Earnings before taxes	**$ 2,958**	$ 3,147	$ 1,330	**$ 10,165**	$ 13,704
Effective tax rate on net earnings [2]	**11%**	26%	(14)%	**19%**	20%

($ millions, except effective tax rates)	Three Months Ended **Dec 31 2023**	Sep 30 2023	Dec 31 2022	Year Ended **Dec 31 2023**	Dec 31 2022
Income tax	**$ 331**	$ 803	$ (190)	**$ 1,932**	$ 2,767
Tax effect on non-operating items [3]	**331**	4	980	**345**	964
Current PRT – North Sea	**13**	—	5	**58**	42
Deferred PRT – North Sea	**33**	(6)	—	**9**	—
Other taxes	**(8)**	(3)	(3)	**(17)**	(16)
Effective tax on adjusted net earnings	**$ 700**	$ 798	$ 792	**$ 2,327**	$ 3,757
Adjusted net earnings from operations [4]	**$ 2,546**	$ 2,850	$ 2,194	**$ 8,533**	$ 12,863
Adjusted net earnings from operations, before taxes	**$ 3,246**	$ 3,648	$ 2,986	**$ 10,860**	$ 16,620
Effective tax rate on adjusted net earnings from operations [5] [6]	**22%**	22%	27%	**21%**	23%

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

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

(3) Includes the net income tax effect on PSUs, unrealized risk management, and government grant income related to abandonment expenditures in 2022, as well as deferred PRT and income tax recoveries related to the recoverability charges recognized in 2023 and 2022.

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

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

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

The effective tax rate on net earnings and adjusted net earnings from operations for the three months and year ended December 31, 2023 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings.

The current and deferred corporate income tax and the current and deferred PRT in the North Sea for the three months and year ended December 31, 2023 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			Year Ended	
($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Exploration and Production					
Exploration and Evaluation Assets					
Net expenditures	**$ 12**	$ (2)	$ 11	**$ 47**	$ 36
Net property dispositions	**—**	(1)	(2)	**(3)**	(3)
Total Exploration and Evaluation Assets	**12**	(3)	9	**44**	33
Property, Plant and Equipment					
Net property (dispositions) acquisitions	**(1)**	8	—	**24**	513
Well drilling, completion and equipping	**274**	352	407	**1,579**	1,545
Production and related facilities	**251**	301	351	**1,267**	1,233
Other	**13**	18	15	**61**	59
Total Property, Plant and Equipment	**537**	679	773	**2,931**	3,350
Total Exploration and Production	**549**	676	782	**2,975**	3,383
Oil Sands Mining and Upgrading					
Project costs	**78**	112	98	**348**	294
Sustaining capital	**320**	286	367	**1,347**	1,171
Turnaround costs	**17**	18	16	**189**	287
Net property (dispositions) acquisitions	**(1)**	6	(40)	**5**	(40)
Other	**1**	2	1	**5**	7
Total Oil Sands Mining and Upgrading	**415**	424	442	**1,894**	1,719
Midstream and Refining	**4**	1	2	**10**	9
Head office	**7**	7	7	**30**	25
Net capital expenditures	**$ 975**	$ 1,108	$ 1,233	**$ 4,909**	$ 5,136
Abandonment expenditures, net (3)	**$ 149**	$ 123	$ 84	**$ 509**	$ 335
By Segment					
North America	**$ 479**	$ 629	$ 677	**$ 2,770**	$ 3,133
North Sea	**11**	14	48	**33**	126
Offshore Africa	**59**	33	57	**172**	124
Oil Sands Mining and Upgrading	**415**	424	442	**1,894**	1,719
Midstream and Refining	**4**	1	2	**10**	9
Head office	**7**	7	7	**30**	25
Net capital expenditures	**$ 975**	$ 1,108	$ 1,233	**$ 4,909**	$ 5,136

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

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

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure the Company is able to maximize utilization of its production facilities, thereby increasing control over production expenses.

Net capital expenditures for the year ended December 31, 2023 were $4,909 million compared with $5,136 million for the year ended December 31, 2022. Net capital expenditures for the year ended December 31, 2023 included base capital expenditures (1) of $3,958 million and strategic growth capital expenditures (1) of $925 million, in accordance with the Company's 2023 capital budget. Net capital expenditures were $975 million for the fourth quarter of 2023 compared with $1,233 million for the fourth quarter of 2022 and $1,108 million for the third quarter of 2023.

In addition, the Company reported abandonment expenditures (2) of $509 million for the year ended December 31, 2023 compared with $335 million for the year ended December 31, 2022. Abandonment expenditures were $149 million for the fourth quarter of 2023 compared with $84 million for the fourth quarter of 2022 and $123 million for the third 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			Year Ended	
(number of net wells)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Net successful crude oil wells (3)	**42**	44	80	**221**	317
Net successful natural gas wells	**9**	10	15	**61**	72
Dry wells	**—**	—	—	**2**	1
Total	**51**	54	95	**284**	390
Success rate	**100%**	100%	100%	**99%**	99%

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

(2) In addition, during the fourth quarter of 2023, on a net basis, the Company drilled 5 service wells in the Company's thermal oil projects. During the year ended December 31, 2023, on a net basis, the Company drilled 334 stratigraphic and 11 service wells in the Oil Sands Mining and Upgrading segment, 24 stratigraphic and 48 service wells in the Company's thermal oil projects, and 2 service wells in the Northern Plains region.

(3) Includes bitumen wells.

North America

During the fourth quarter of 2023, the Company drilled 9 net natural gas wells, 32 net primary heavy crude oil wells, and 10 net light crude oil wells.

(1) Item is a component of net capital expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A for more details on net capital expenditures.

(2) A reconciliation of abandonment expenditures and abandonment expenditures, net is presented in the "Non-GAAP and Other Financial Measures" section of this MD&A.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022
Adjusted working capital [(1)]	**$ 712**	$ 866	$ (1,190)
Long-term debt, net [(2)]	**$ 9,922**	$ 11,519	$ 10,525
Shareholders' equity	**$ 39,832**	$ 39,634	$ 38,175
Debt to book capitalization [(2)]	**19.9%**	22.5%	21.6%
After-tax return on average capital employed [(3)]	**17.2%**	15.0%	22.1%

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

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

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

As at December 31, 2023, 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, 2022. 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 maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
  - During the third quarter of 2023, the Company extended its $500 million revolving credit facility, originally maturing February 2024, to February 2025.
  - During the second quarter of 2023, the Company extended its $2,425 million revolving syndicated credit facility, originally maturing June 2024, to 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.
  - During the fourth quarter of 2023, the Company repaid $405 million of 1.45% 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, replacing the Company's previous base shelf prospectus which would have expired in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- In 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, replacing the Company's previous base shelf prospectus which would have expired in August 2023. 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 December 31, 2023, 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 $6,852 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. At December 31, 2023, 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 $9,922 million as at December 31, 2023, resulting in a debt to book capitalization ratio (1) of 19.9% (December 31, 2022 – 21.6%); 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 timing of acquisitions, the execution of the Company's capital program, and commodity price and foreign currency volatility. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt as at December 31, 2023 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 December 31, 2023, 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 December 31, 2023, 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)	$ 980	$ 1,584	$ 2,317	$ 5,978
Other long-term liabilities (2)	$ 302	$ 184	$ 428	$ 645
Interest and other financing expense (3)	$ 582	$ 518	$ 1,257	$ 3,362

(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, $298 million; one to less than two years, $184 million; two to less than five years, $428 million; and thereafter, $645 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2023.

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

Share Capital

As at December 31, 2023, there were 1,072,408,000 common shares outstanding (December 31, 2022 – 1,102,636,000 common shares) and 26,205,000 stock options outstanding (December 31, 2022 – 31,150,000). As at February 27, 2024, the Company had 1,070,845,000 common shares outstanding and 28,296,000 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 payable 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 November 2, 2022, the Board of Directors approved a 13% increase in the quarterly dividend to $0.85 per common share. On August 3, 2022, the Board of Directors approved a special dividend of $1.50 per common share. On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share, from $0.5875 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 8, 2023, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 92,296,006 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2023 and ending March 12, 2024.

For the year ended December 31, 2023, the Company purchased 40,050,000 common shares at a weighted average price of $82.86 per common share for a total cost of $3,318 million. Retained earnings were reduced by $2,929 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2023, up to and including February 27, 2024, the Company purchased 4,000,000 common shares at a weighted average price of $85.54 per common share for a total cost of $342 million.

On February 28, 2024, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of Normal Course Issuer Bid, up to 10% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

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 December 31, 2023:

($ millions)	2024	2025	2026	2027	2028	Thereafter
Product transportation and processing (1)	$ 1,572	$ 1,595	$ 1,408	$ 1,358	$ 1,242	$ 13,380
North West Redwater Partnership service toll (2)	$ 158	$ 157	$ 139	$ 126	$ 130	$ 4,985
Offshore vessels and equipment	$ 36	$ —	$ —	$ —	$ —	$ —
Field equipment and power	$ 38	$ 25	$ 23	$ 22	$ 22	$ 193
Other	$ 145	$ 111	$ 112	$ 25	$ 26	$ 355

(1) The Company's commitment for the 20-year product transportation agreement on the Trans Mountain Pipeline Expansion 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 $3,011 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, 2022.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the year ended December 31, 2023 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			Year Ended	
($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Net earnings	**$ 2,627**	$ 2,344	$ 1,520	**$ 8,233**	$ 10,937
Share-based compensation, net of tax (1)	**51**	295	309	**474**	780
Unrealized risk management (gain) loss, net of tax (2)	**(9)**	2	11	**7**	(25)
Unrealized foreign exchange (gain) loss, net of tax (3)	**(276)**	250	(203)	**(260)**	852
Realized foreign exchange loss (gain), net of tax (4)	**—**	—	7	**—**	(62)
Loss (gain) from investments, net of tax (5)	**40**	(41)	(88)	**(34)**	(182)
Recoverability charge, net of tax (6) (7)	**113**	—	651	**113**	651
Other, net of tax (8)	**—**	—	(13)	**—**	(88)
Non-operating items, net of tax	**(81)**	506	674	**300**	1,926
Adjusted net earnings from operations	**$ 2,546**	$ 2,850	$ 2,194	**$ 8,533**	$ 12,863

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings. Pre-tax share-based compensation for the three months ended December 31, 2023 was an expense of $57 million (three months ended September 30, 2023 – $298 million expense, three months ended December 31, 2022 – $319 million expense; year ended December 31, 2023 – $491 million expense, year ended December 31, 2022 – $804 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 gain for the three months ended December 31, 2023 was $7 million (three months ended September 30, 2023 – $3 million loss, three months ended December 31, 2022 – $15 million loss; year ended December 31, 2023 – $12 million loss, year ended December 31, 2022 – $28 million gain).

(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) During the fourth quarter of 2022, the Company early repaid US$1,000 million of 2.95% debt securities, originally due January 15, 2023, resulting in a realized foreign exchange loss of $7 million. During the second quarter of 2022, the Company settled the US$550 million cross currency swap designated as a cash flow hedge of a portion of the US$1,100 million 6.25% US dollar debt securities due March 2038, resulting in a realized foreign exchange gain of $69 million. Pre- and after-tax amounts for the realized foreign exchange gain on settlement of the swap are the same.

(5) 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.

(6) The Company recognized a pre-tax recoverability charge of $436 million in depletion, depreciation and amortization expense related to revised project scope and the current cost environment for planned decommissioning and abandonment activities at the Ninian field in the North Sea in 2023. The costs are considered to be capital in nature, consistent with the treatment of all abandonment related expenditures for the purpose of the Company's non-GAAP measures.

(7) The Company recognized a pre-tax recoverability charge of $1,620 million in depletion, depreciation and amortization expense at December 31, 2022 relating to the de-booking of reserves at the Ninian field in the North Sea in 2022.

(8) Other relates to the impact of government grant income under the provincial well-site rehabilitation programs. Pre-tax other for the three months ended December 31, 2023 was $nil (three months ended September 30, 2023 – $nil, three months ended December 31, 2022 – $16 million; year ended December 31, 2023 – $nil, year ended December 31, 2022 – $114 million).

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 excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets. The Company considers adjusted funds flow a key measure in evaluating its performance, as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment, repay debt, and provide returns to shareholders through dividends and share buybacks. A reconciliation for adjusted funds flow, from cash flows from operating activities is presented below.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Cash flows from operating activities	**$ 4,815**	$ 3,498	$ 4,544	**$ 12,353**	$ 19,391
Net change in non-cash working capital	**(562)**	1,088	(517)	**2,417**	(79)
Abandonment expenditures, net (1)	**149**	123	84	**509**	335
Movements in other long-term assets (2)	**17**	(25)	65	**(5)**	144
Adjusted funds flow	**$ 4,419**	$ 4,684	$ 4,176	**$ 15,274**	$ 19,791

(1) Non-GAAP Financial Measure. A reconciliation of abandonment expenditures, net is presented in the "Abandonment Expenditures, net" section below.

(2) 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.

Abandonment Expenditures, net

Abandonment expenditures, net, is a non-GAAP financial measure that represents the abandonment expenditures to settle asset retirement obligations as reflected in the Company's historical annual capital budgets. Abandonment expenditures, net is calculated as abandonment expenditures, as presented in the Company's consolidated Statements of Cash Flows, adjusted for the impact of government grant income under the provincial well-site rehabilitation programs. A reconciliation of abandonment expenditures, net is presented below.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Abandonment expenditures	**$ 149**	$ 123	$ 100	**$ 509**	$ 449
Government grants for abandonment expenditures	**—**	—	(16)	**—**	(114)
Abandonment expenditures, net	**$ 149**	$ 123	$ 84	**$ 509**	$ 335

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 include 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.

	Three Months Ended			Year Ended	
($ millions, except bbl/d and $/bbl)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Crude oil and NGLs (bbl/d)					
North America	**526,350**	516,038	482,931	**497,604**	480,691
International					
North Sea	**15,032**	7,839	20,854	**10,749**	13,215
Offshore Africa	**17,705**	12,769	14,059	**14,882**	14,866
Total International	**32,737**	20,608	34,913	**25,631**	28,081
Total sales volumes	**559,087**	536,646	517,844	**523,235**	508,772
Crude oil and NGLs sales [(1)]	**$ 4,790**	$ 5,351	$ 4,505	**$ 18,387**	$ 22,072
Less: Blending and feedstock costs [(2)]	**1,222**	1,014	1,202	**4,568**	5,239
Realized crude oil and NGLs sales	**$ 3,568**	$ 4,337	$ 3,303	**$ 13,819**	$ 16,833
Realized price ($/bbl)	**$ 69.39**	$ 87.83	$ 69.34	**$ 72.36**	$ 90.64

(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.

	Three Months Ended			Year Ended	
($ millions, except BOE/d and $/BOE)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Barrels of oil equivalent (BOE/d)					
North America	**895,996**	872,555	833,719	**854,138**	826,526
International					
North Sea	**15,296**	8,022	21,375	**11,034**	13,598
Offshore Africa	**19,567**	14,530	15,171	**16,638**	16,933
Total International	**34,863**	22,552	36,546	**27,672**	30,531
Total sales volumes	**930,859**	895,107	870,265	**881,810**	857,057
Barrels of oil equivalent sales [(1)]	**$ 5,365**	$ 5,908	$ 5,751	**$ 20,820**	$ 27,071
Less: Blending and feedstock costs [(2)]	**1,222**	1,014	1,202	**4,568**	5,239
Less: Sulphur (income) expense	**(2)**	1	(3)	**(14)**	(88)
Realized barrels of oil equivalent sales	**$ 4,145**	$ 4,893	$ 4,552	**$ 16,266**	$ 21,920
Realized price ($/BOE)	**$ 48.41**	$ 59.40	$ 56.83	**$ 50.54**	$ 70.07

(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			Year Ended	
($ millions, except $ per unit amounts)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Transportation, blending and feedstock (1)	**$ 1,531**	$ 1,326	$ 1,506	**$ 5,816**	$ 6,401
Less: Blending and feedstock costs	**1,222**	1,014	1,202	**4,568**	5,239
Transportation	**$ 309**	$ 312	$ 304	**$ 1,248**	$ 1,162
Transportation ($/BOE)	**$ 3.61**	$ 3.78	$ 3.80	**$ 3.88**	$ 3.72
Amounts attributed to crude oil and NGLs	**$ 197**	$ 200	$ 196	**$ 807**	$ 767
Transportation ($/bbl)	**$ 3.83**	$ 4.07	$ 4.11	**$ 4.23**	$ 4.13
Amounts attributed to natural gas	**$ 112**	$ 112	$ 108	**$ 441**	$ 395
Transportation ($/Mcf)	**$ 0.54**	$ 0.56	$ 0.55	**$ 0.56**	$ 0.51

(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 include 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			Year Ended	
($ millions, except $/bbl and royalty rates)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Crude oil and NGLs sales (1)	**$ 4,451**	$ 5,135	$ 4,124	**$ 17,375**	$ 20,755
Less: Blending and feedstock costs (2)	**1,222**	1,014	1,202	**4,568**	5,239
Realized crude oil and NGLs sales	**$ 3,229**	$ 4,121	$ 2,922	**$ 12,807**	$ 15,516
Realized crude oil and NGLs prices ($/bbl)	**$ 66.69**	$ 86.77	$ 65.79	**$ 70.51**	$ 88.43
Crude oil and NGLs royalties (3)	**$ 567**	$ 845	$ 625	**$ 2,340**	$ 3,445
Crude oil and NGLs royalty rates	**18%**	21%	21%	**18%**	22%

(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) including 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			Year Ended	
($ millions, except for bbl/d and $/bbl)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
SCO sales volumes (bbl/d)	**491,339**	492,926	433,731	**449,282**	428,820
Crude oil and NGLs sales [1]	**$ 5,042**	$ 5,591	$ 4,935	**$ 18,661**	$ 20,804
Less: Blending and feedstock costs	**579**	670	795	**2,253**	2,384
Realized SCO sales	**$ 4,463**	$ 4,921	$ 4,140	**$ 16,408**	$ 18,420
Realized SCO sales price ($/bbl)	**$ 98.73**	$ 108.55	$ 103.79	**$ 100.06**	$ 117.69
Transportation, blending and feedstock [2]	**$ 663**	$ 768	$ 867	**$ 2,563**	$ 2,652
Less: Blending and feedstock costs	**579**	670	795	**2,253**	2,384
Transportation	**$ 84**	$ 98	$ 72	**$ 310**	$ 268
Transportation ($/bbl)	**$ 1.85**	$ 2.18	$ 1.80	**$ 1.89**	$ 1.71

(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 composition of the Company's capital budget, and in evaluating performance. 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			Year Ended	
($ millions)	**Dec 31 2023**	Sep 30 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Cash flows used in investing activities	**$ 946**	$ 1,199	$ 1,262	**$ 4,858**	$ 4,987
Net change in non-cash working capital	**29**	(91)	(29)	**51**	149
Net capital expenditures [1]	**975**	1,108	1,233	**4,909**	5,136
Abandonment expenditures, net [2]	**149**	123	84	**509**	335
Capital and abandonment expenditures	**$ 1,124**	$ 1,231	$ 1,317	**$ 5,418**	$ 5,471

(1) For the year ended December 31, 2023 includes base capital expenditures of $3,958 million, and strategic growth capital expenditures of $925 million. Strategic growth capital expenditures represent the allocation of the Company's free cash flow that will be directed to strategic capital growth opportunities that target to increase production volumes in future periods and that exceed the Company's base capital expenditures for the current fiscal year, as outlined in the Company's capital budget.

(2) Non-GAAP Financial Measure. A reconciliation of abandonment expenditures, net is presented in the "Abandonment Expenditures, net" section above.

Liquidity

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

($ millions)	Dec 31 2023	Sep 30 2023	Dec 31 2022
Undrawn bank credit facilities	**$ 5,450**	$ 5,450	$ 5,520
Cash and cash equivalents	**877**	125	920
Investments	**525**	565	491
Liquidity	**$ 6,852**	$ 6,140	$ 6,931

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)	Dec 31 2023	Sep 30 2023	Dec 31 2022
Long-term debt	**$ 10,799**	$ 11,644	$ 11,445
Less: cash and cash equivalents	**877**	125	920
Long-term debt, net	**$ 9,922**	$ 11,519	$ 10,525

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)	Dec 31 2023	Sep 30 2023	Dec 31 2022
Interest adjusted after-tax return:			
Net earnings, 12 months trailing	**$ 8,233**	$ 7,126	$ 10,937
Interest and other financing expense, net of tax, 12 months trailing (1)	**490**	459	424
Interest adjusted after-tax return	**$ 8,723**	$ 7,585	$ 11,361
12 months average current portion long-term debt (2)	**$ 1,259**	$ 1,337	$ 1,359
12 months average long-term debt (2)	**10,354**	10,706	11,761
12 months average common shareholders' equity (2)	**38,974**	38,635	38,218
12 months average capital employed	**$ 50,587**	$ 50,678	$ 51,338
After-tax return on average capital employed	**17.2%**	15.0%	22.1%

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

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

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Dec 31 2023**	Dec 31 2022
ASSETS			
Current assets			
Cash and cash equivalents		**$ 877**	$ 920
Accounts receivable		**3,189**	3,555
Inventory		**2,034**	1,815
Prepaids and other		**471**	215
Investments	6	**525**	491
Current portion of other long-term assets	7	**71**	61
		7,167	7,057
Exploration and evaluation assets	3	**2,208**	2,226
Property, plant and equipment	4	**64,581**	64,859
Lease assets	5	**1,458**	1,447
Other long-term assets	7	**541**	553
		$ 75,955	$ 76,142
LIABILITIES			
Current liabilities			
Accounts payable		**$ 1,418**	$ 1,341
Accrued liabilities		**3,534**	4,209
Current income taxes payable		**—**	1,324
Current portion of long-term debt	8	**980**	404
Current portion of other long-term liabilities	9	**1,503**	1,373
		7,435	8,651
Long-term debt	8	**9,819**	11,041
Other long-term liabilities	9	**8,686**	8,161
Deferred income taxes		**10,183**	10,114
		36,123	37,967
SHAREHOLDERS' EQUITY			
Share capital	11	**10,712**	10,294
Retained earnings		**28,948**	27,672
Accumulated other comprehensive income	12	**172**	209
		39,832	38,175
		$ 75,955	$ 76,142

Commitments and contingencies (note 16)

Approved by the Board of Directors on February 28, 2024.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Dec 31 2023	Three Months Ended Dec 31 2022	Year Ended Dec 31 2023	Year Ended Dec 31 2022
Product sales	17	**$ 10,679**	$ 11,012	**$ 40,835**	$ 49,530
Less: royalties		**(1,126)**	(1,323)	**(4,867)**	(7,232)
Revenue		**9,553**	9,689	**35,968**	42,298
Expenses					
Production		**2,056**	2,309	**8,480**	8,712
Transportation, blending and feedstock		**2,349**	2,601	**9,302**	9,973
Depletion, depreciation and amortization	4,5	**2,061**	3,129	**6,413**	7,353
Administration		**119**	108	**452**	415
Share-based compensation	9	**57**	319	**491**	804
Asset retirement obligation accretion	9	**91**	82	**366**	281
Interest and other financing expense		**117**	76	**636**	549
Risk management activities (gain) loss	15	**(24)**	13	**(2)**	(35)
Foreign exchange (gain) loss		**(265)**	(185)	**(279)**	738
Loss (gain) from investments	6	**34**	(93)	**(56)**	(196)
		6,595	8,359	**25,803**	28,594
Earnings before taxes		**2,958**	1,330	**10,165**	13,704
Current income tax expense	10	**505**	399	**1,879**	2,906
Deferred income tax (recovery) expense	10	**(174)**	(589)	**53**	(139)
Net earnings		**$ 2,627**	$ 1,520	**$ 8,233**	$ 10,937
Net earnings per common share					
Basic	14	**$ 2.43**	$ 1.37	**$ 7.54**	$ 9.64
Diluted	14	**$ 2.41**	$ 1.36	**$ 7.47**	$ 9.52

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2023	Three Months Ended Dec 31 2022	Year Ended Dec 31 2023	Year Ended Dec 31 2022
Net earnings	**$ 2,627**	$ 1,520	**$ 8,233**	$ 10,937
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 (2022 – $nil) – three months ended; $nil (2022 – $1 million) – year ended	**—**	—	**2**	4
Reclassification to net earnings, net of taxes of $nil (2022 – $nil) – three months ended; $nil (2022 – $1 million) – year ended	**—**	—	**(5)**	(6)
	—	—	**(3)**	(2)
Foreign currency translation adjustment				
Translation of net investment	**(36)**	(21)	**(34)**	212
Other comprehensive (loss) income, net of taxes	**(36)**	(21)	**(37)**	210
Comprehensive income	**$ 2,591**	$ 1,499	**$ 8,196**	$ 11,147

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended **Dec 31 2023**	Dec 31 2022
Share capital	11		
Balance – beginning of year		**$ 10,294**	$ 10,168
Issued upon exercise of stock options		**372**	442
Previously recognized liability on stock options exercised for common shares		**435**	387
Purchase of common shares under Normal Course Issuer Bid		**(389)**	(703)
Balance – end of year		**10,712**	10,294
Retained earnings			
Balance – beginning of year		**27,672**	26,778
Net earnings		**8,233**	10,937
Dividends on common shares	11	**(4,028)**	(5,175)
Purchase of common shares under Normal Course Issuer Bid	11	**(2,929)**	(4,868)
Balance – end of year		**28,948**	27,672
Accumulated other comprehensive income (loss)	12		
Balance – beginning of year		**209**	(1)
Other comprehensive (loss) income, net of taxes		**(37)**	210
Balance – end of year		**172**	209
Shareholders' equity		**$ 39,832**	$ 38,175

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Dec 31 2023**	Three Months Ended Dec 31 2022	Year Ended **Dec 31 2023**	Year Ended Dec 31 2022
Operating activities					
Net earnings		**$ 2,627**	$ 1,520	**$ 8,233**	$ 10,937
Non-cash items					
Depletion, depreciation and amortization	4,5	**2,061**	3,129	**6,413**	7,353
Share-based compensation		**57**	319	**491**	804
Asset retirement obligation accretion		**91**	82	**366**	281
Unrealized risk management (gain) loss		**(7)**	15	**12**	(28)
Unrealized foreign exchange (gain) loss		**(276)**	(203)	**(260)**	852
Loss (gain) from investments	6	**40**	(88)	**(34)**	(182)
Deferred income tax (recovery) expense		**(174)**	(589)	**53**	(139)
Realized foreign exchange loss (gain) [(1)]		**—**	7	**—**	(62)
Proceeds on settlement of cross currency swap		**—**	—	**—**	89
Abandonment expenditures	9	**(149)**	(100)	**(509)**	(449)
Other		**(17)**	(65)	**5**	(144)
Net change in non-cash working capital		**562**	517	**(2,417)**	79
Cash flows from operating activities		**4,815**	4,544	**12,353**	19,391
Financing activities					
Repayment of bank credit facilities and commercial paper, net	8	**(202)**	—	**—**	(1,156)
Repayment of medium-term notes	8	**(405)**	(18)	**(416)**	(1,498)
Repayment of US dollar debt securities	8	**—**	(1,356)	**—**	(1,356)
Proceeds on settlement of cross currency swap		**—**	—	**—**	69
Payment of lease liabilities	5	**(79)**	(83)	**(285)**	(232)
Issue of common shares on exercise of stock options	11	**98**	110	**372**	442
Dividends on common shares		**(980)**	(834)	**(3,891)**	(4,926)
Purchase of common shares under Normal Course Issuer Bid	11	**(1,549)**	(746)	**(3,318)**	(5,571)
Cash flows used in financing activities		**(3,117)**	(2,927)	**(7,538)**	(14,228)
Investing activities					
Net expenditures on exploration and evaluation assets	3,17	**(12)**	(9)	**(44)**	(33)
Net expenditures on property, plant and equipment	4,17	**(963)**	(1,224)	**(4,865)**	(5,103)
Net change in non-cash working capital		**29**	(29)	**51**	149
Cash flows used in investing activities		**(946)**	(1,262)	**(4,858)**	(4,987)
Increase (decrease) in cash and cash equivalents		**752**	355	**(43)**	176
Cash and cash equivalents – beginning of period		**125**	565	**920**	744
Cash and cash equivalents – end of period		**$ 877**	$ 920	**$ 877**	$ 920
Interest paid on long-term debt, net		**$ 112**	$ 131	**$ 602**	$ 613
Income taxes paid, net		**$ 761**	$ 575	**$ 3,317**	$ 3,057

(1) Consists of the realized foreign exchange gain on settlement of cross currency swap and the realized foreign exchange loss on repayment of US dollar debt securities in 2022.

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, 2022, 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, 2022.

Critical Accounting Estimates and Judgements

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

2. CHANGE IN ACCOUNTING POLICIES

In May 2023, the IASB issued amendments to IAS 12 "Income Taxes" related to the accounting for deferred taxes arising in those jurisdictions implementing the Organization for Economic Co-operation and Development's Pillar Two model rules ("Pillar Two Legislation"). The amendments were effective immediately and adopted in the second quarter of 2023 and did not have a significant impact on the Company's interim consolidated financial statements.

In May 2021, the IASB issued amendments to IAS 12 "Income Taxes" to require companies to recognize deferred tax on particular transactions that, on initial recognition, give rise to equal amounts of taxable and deductible temporary differences. The amendments were adopted on January 1, 2023 and did not have a significant impact on the Company's interim consolidated financial statements.

In February 2021, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" to require companies to disclose their material accounting policy information rather than their significant accounting policies. To support this amendment the IASB also amended IFRS Practice Statement 2 "Making Materiality Judgements". The amendments were adopted on January 1, 2023 and did not have a significant 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, 2022	$ 2,026	$ —	$ 98	$ 102	$ 2,226
Additions	**45**	**—**	**3**	**—**	**48**
Transfers to property, plant and equipment	**(38)**	**—**	**—**	**(25)**	**(63)**
Derecognitions and other	**(2)**	**—**	**—**	**—**	**(2)**
Foreign exchange adjustments	**—**	**—**	**(1)**	**—**	**(1)**
At December 31, 2023	**$ 2,031**	**$ —**	**$ 100**	**$ 77**	**$ 2,208**

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, 2022	$ 81,075	$ 8,258	$ 4,332	$ 47,732	$ 474	$ 536	$ 142,407
Additions / Acquisitions	**2,752**	**33**	**169**	**1,895**	**10**	**30**	**4,889**
Transfers from exploration & evaluation assets	**38**	**—**	**—**	**25**	**—**	**—**	**63**
Change in asset retirement obligation estimates	**199**	**525**	**18**	**193**	**—**	**—**	**935**
Derecognitions (1)	**(581)**	**—**	**—**	**(470)**	**—**	**—**	**(1,051)**
Foreign exchange adjustments and other	**—**	**(210)**	**(110)**	**—**	**—**	**—**	**(320)**
At December 31, 2023	**$ 83,483**	**$ 8,606**	**$ 4,409**	**$ 49,375**	**$ 484**	**$ 566**	**$ 146,923**
Accumulated depletion and depreciation							
At December 31, 2022	$ 55,835	$ 8,106	$ 3,277	$ 9,712	$ 198	$ 420	$ 77,548
Expense	**3,592**	**40**	**177**	**1,856**	**15**	**24**	**5,704**
Derecognitions (1)	**(581)**	**—**	**—**	**(470)**	**—**	**—**	**(1,051)**
Recoverability charge	**—**	**436**	**—**	**—**	**—**	**—**	**436**
Foreign exchange adjustments and other	**(6)**	**(200)**	**(96)**	**7**	**—**	**—**	**(295)**
At December 31, 2023	**$ 58,840**	**$ 8,382**	**$ 3,358**	**$ 11,105**	**$ 213**	**$ 444**	**$ 82,342**
Net book value							
At December 31, 2023	**$ 24,643**	**$ 224**	**$ 1,051**	**$ 38,270**	**$ 271**	**$ 122**	**$ 64,581**
At December 31, 2022	$ 25,240	$ 152	$ 1,055	$ 38,020	$ 276	$ 116	$ 64,859

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

Prevailing regulatory and economic conditions and the increasingly challenging commercial outlook in the United Kingdom, including the impact of higher natural gas and carbon costs, led the Company to assess the viability of its North Sea operations in 2022. Following a detailed review of its development plans, the Company determined that the Ninian field is no longer economic, de-booked crude oil reserves as at December 31, 2022 and is accelerating abandonment. As a result, the Company completed a recoverability assessment of its assets in the North Sea, and recognized a non-cash charge of $651 million (after-tax) related to the Ninian field property, plant and equipment, comprised of a recoverability charge of $1,620 million recognized in depletion, depreciation and amortization expense, net of deferred tax recoveries of $969 million.

As at December 31, 2023, as a result of revised project scope and the current cost environment, the Company recognized a non-cash charge of $113 million (after-tax) related to an increase in its estimate of the future abandonment costs for the Ninian field in the North Sea. The non-cash charge is comprised of a recoverability charge of $436 million recognized in depletion, depreciation and amortization expense, net of deferred tax recoveries of $323 million. The Company's estimate of its asset retirement obligation liability, including the Ninian field recoverability charge and associated tax recoveries, is subject to revision in future periods as abandonment efforts progress.

As at December 31, 2023, the Company completed its normal course assessment of the recoverability of its other property, plant and equipment and exploration and evaluation assets, and determined the carrying amounts of all its cash generating units to be recoverable.

5. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2022	$ 912	$ 377	$ 97	$ 61	$ 1,447
Additions	**27**	**218**	**49**	**23**	**317**
Depreciation	**(98)**	**(111)**	**(45)**	**(19)**	**(273)**
Foreign exchange adjustments and other	**(1)**	**(2)**	**(30)**	**—**	**(33)**
At December 31, 2023	**$ 840**	**$ 482**	**$ 71**	**$ 65**	**$ 1,458**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at December 31, 2023 were as follows:

	Dec 31 2023	Dec 31 2022
Lease liabilities	**$ 1,555**	$ 1,540
Less: current portion	**298**	244
	$ 1,257	$ 1,296

Total cash outflows for leases for the three months ended December 31, 2023, including payments related to short-term leases not reported as lease assets, were $302 million (three months ended December 31, 2022 – $322 million; year ended December 31, 2023 – $1,325 million; year ended December 31, 2022 – $1,204 million). Interest expense on leases for the three months ended December 31, 2023 was $16 million (three months ended December 31, 2022 – $15 million; year ended December 31, 2023 – $64 million; year ended December 31, 2022 – $60 million).

6. INVESTMENTS

As at December 31, 2023, the Company had the following investment:

	Dec 31 2023	Dec 31 2022
Investment in PrairieSky Royalty Ltd.	**$ 525**	$ 491

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

	Three Months Ended		Year Ended	
	Dec 31 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Loss (gain) from investment	**$ 40**	$ (88)	**$ (34)**	$ (182)
Dividend income	**(6)**	(5)	**(22)**	(14)
	$ 34	$ (93)	**$ (56)**	$ (196)

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 December 31, 2023, the market price per common share was $23.20 (December 31, 2022 – $21.70).

7. OTHER LONG-TERM ASSETS

	Dec 31 2023	Dec 31 2022
Long-term prepayments, contracts and other (1)	**$ 279**	$ 269
Prepaid cost of service tolls	**179**	199
Long-term inventory	**141**	137
Risk management (note 15)	**13**	9
	612	614
Less: current portion	**71**	61
	$ 541	$ 553

(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 December 31, 2023, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $555 million (December 31, 2022 – $551 million). For the three months ended December 31, 2023, the Company's unrecognized share of the equity loss was $5 million (year ended December 31, 2023 – unrecognized equity loss of $4 million; three months ended December 31, 2022 – recovery of unrecognized equity losses of $37 million; year ended December 31, 2022 – recovery of unrecognized equity losses of $11 million).

8. LONG-TERM DEBT

	Dec 31 2023	Dec 31 2022
Canadian dollar denominated debt, unsecured		
Medium-term notes	**$ 1,286**	$ 1,702
US dollar denominated debt, unsecured		
US dollar debt securities (December 31, 2023 – US$7,250 million; December 31, 2022 – US$7,250 million)	**9,573**	9,812
Long-term debt before transaction costs and original issue discounts, net	**10,859**	11,514
Less: original issue discounts, net (1)	**11**	13
transaction costs (1) (2)	**49**	56
	10,799	11,445
Less: current portion of long-term debt (1) (2)	**980**	404
	$ 9,819	$ 11,041

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

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

Bank Credit Facilities and Commercial Paper

As at December 31, 2023, 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.

During the third quarter of 2023, the Company extended its $500 million revolving credit facility, originally maturing February 2024, to February 2025.

During the second quarter of 2023, the Company extended its $2,425 million revolving syndicated credit facility, originally maturing June 2024, to 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 year ended December 31, 2023 was 4.8% (December 31, 2022 – 4.3%).

As at December 31, 2023, letters of credit and guarantees aggregating to $446 million were outstanding (December 31, 2022 – $637 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, replacing the Company's previous base shelf prospectus which would have expired in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

During the fourth quarter of 2023, the Company repaid $405 million of 1.45% medium-term notes.

US Dollar Debt Securities

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, replacing the Company's previous base shelf prospectus which would have expired in August 2023. 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

	Dec 31 2023	Dec 31 2022
Asset retirement obligations	**$ 7,690**	$ 6,908
Lease liabilities (note 5)	**1,555**	1,540
Share-based compensation	**780**	832
Transportation and processing contracts	**87**	159
Risk management (note 15)	**4**	3
Other	**73**	92
	10,189	9,534
Less: current portion	**1,503**	1,373
	$ 8,686	$ 8,161

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, 2022 – 5.6%) and inflation rates of up to 2% (December 31, 2022 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Dec 31 2023	Dec 31 2022
Balance – beginning of year	**$ 6,908**	$ 6,806
Liabilities incurred	**25**	20
Liabilities acquired, net	**—**	11
Liabilities settled	**(509)**	(449)
Asset retirement obligation accretion	**366**	281
Revision of cost, inflation and timing estimates (1)	**621**	897
Impact of regulatory changes (2)	**—**	982
Change in discount rates	**314**	(1,698)
Foreign exchange adjustments	**(35)**	58
Balance – end of year	**7,690**	6,908
Less: current portion	**634**	495
	$ 7,056	$ 6,413

(1) Includes normal course revisions of cost, inflation and timing estimates, as well as revisions related to the acceleration of the abandonment and subsequent cost estimate increases on future abandonment at the Ninian field assets in the North Sea in 2022 and 2023.

(2) Reflects changes to the estimated timing of settlement of the Company's asset retirement obligations due to provincial regulatory changes in Alberta, British Columbia, and Saskatchewan in 2022.

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.

	Dec 31 2023	Dec 31 2022
Balance – beginning of year	**$ 832**	$ 489
Share-based compensation expense	**491**	804
Cash payment for stock options surrendered and PSUs vested	**(110)**	(79)
Transferred to common shares	**(435)**	(387)
Other	**2**	5
Balance – end of year	**780**	832
Less: current portion	**538**	559
	$ 242	$ 273

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Year Ended	
Expense (recovery)	**Dec 31 2023**	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Current corporate income tax – North America (1)	**$ 487**	$ 345	**$ 1,853**	$ 2,789
Current corporate income tax – North Sea	**3**	33	**(6)**	69
Current corporate income tax – Offshore Africa	**20**	23	**73**	74
Current PRT (2) – North Sea	**(13)**	(5)	**(58)**	(42)
Other taxes	**8**	3	**17**	16
Current income tax	**505**	399	**1,879**	2,906
Deferred corporate income tax	**64**	(148)	**267**	302
Deferred PRT (2) – North Sea	**(238)**	(441)	**(214)**	(441)
Deferred income tax	**(174)**	(589)	**53**	(139)
Income tax	**$ 331**	$ (190)	**$ 1,932**	$ 2,767

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

(2) Petroleum Revenue Tax.

As at December 31, 2022, the Company recognized deferred tax recoveries comprised of a deferred corporate income tax recovery of $528 million and a deferred PRT recovery of $441 million in connection with the Company's de-booking of its crude oil reserves and acceleration of the abandonment at the Ninian field in the North Sea (note 4).

As at December 31, 2023, the Company recognized deferred tax recoveries comprised of a deferred corporate income tax recovery of $118 million and a deferred PRT recovery of $205 million in connection with the increase in the Company's estimate of future abandonment costs for the planned decommissioning activities at the Ninian field in the North Sea (note 4).

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued Common Shares	Year Ended Dec 31, 2023	
	Number of shares (thousands)	**Amount**
Balance – beginning of year	**1,102,636**	**$ 10,294**
Issued upon exercise of stock options	**9,822**	**372**
Previously recognized liability on stock options exercised for common shares	**—**	**435**
Purchase of common shares under Normal Course Issuer Bid	**(40,050)**	**(389)**
Balance – end of year	**1,072,408**	**$ 10,712**

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 payable 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 November 2, 2022, the Board of Directors approved a 13% increase in the quarterly dividend to $0.85 per common share. On August 3, 2022, the Board of Directors approved a special dividend of $1.50 per common share. On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share, from $0.5875 per common share.

Normal Course Issuer Bid

On March 8, 2023, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 92,296,006 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2023 and ending March 12, 2024.

For the year ended December 31, 2023, the Company purchased 40,050,000 common shares at a weighted average price of $82.86 per common share for a total cost of $3,318 million. Retained earnings were reduced by $2,929 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2023, up to and including February 27, 2024, the Company purchased 4,000,000 common shares at a weighted average price of $85.54 per common share for a total cost of $342 million.

On February 28, 2024, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of Normal Course Issuer Bid, up to 10% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

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 December 31, 2023:

	Year Ended Dec 31, 2023	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of year	**31,150**	**$ 42.37**
Granted	**7,024**	**$ 80.17**
Exercised for common shares	**(9,822)**	**$ 37.84**
Surrendered for cash settlement	**(218)**	**$ 38.77**
Forfeited	**(1,929)**	**$ 50.86**
Outstanding – end of year	**26,205**	**$ 53.60**
Exercisable – end of year	**3,672**	**$ 42.14**

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:

	Dec 31 2023	Dec 31 2022
Derivative financial instruments designated as cash flow hedges	**$ 72**	$ 75
Foreign currency translation adjustment	**100**	134
	$ 172	$ 209

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 timing of acquisitions, the execution of the Company's capital program, and commodity price and foreign currency volatility. As at December 31, 2023, the ratio was below the target range at 19.9%.

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.

	Dec 31 2023	Dec 31 2022
Long-term debt	**$ 10,799**	$ 11,445
Less: cash and cash equivalents	**877**	920
Long-term debt, net	**$ 9,922**	$ 10,525
Total shareholders' equity	**$ 39,832**	$ 38,175
Debt to book capitalization	**19.9%**	21.6%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2023, the Company was in compliance with this covenant.

14. NET EARNINGS PER COMMON SHARE

		Three Months Ended		Year Ended	
		Dec 31 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Weighted average common shares outstanding – basic (thousands of shares)		**1,079,824**	1,106,042	**1,091,312**	1,134,960
Effect of dilutive stock options (thousands of shares)		**10,002**	13,529	**10,812**	14,222
Weighted average common shares outstanding – diluted (thousands of shares)		**1,089,826**	1,119,571	**1,102,124**	1,149,182
Net earnings		**$ 2,627**	$ 1,520	**$ 8,233**	$ 10,937
Net earnings per common share	– basic	**$ 2.43**	$ 1.37	**$ 7.54**	$ 9.64
	– diluted	**$ 2.41**	$ 1.36	**$ 7.47**	$ 9.52

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)	**Dec 31 2023**	Dec 31 2022
Balance – beginning of year	**$ 6**	$ 55
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities (1) (2)	**3**	70
Foreign exchange	**—**	(119)
Balance – end of year	**9**	6
Less: current portion	**8**	—
	$ 1	$ 6

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

	Three Months Ended		Year Ended	
	Dec 31 2023	Dec 31 2022	**Dec 31 2023**	Dec 31 2022
Net realized risk management gain	**$ (17)**	$ (2)	**$ (14)**	$ (7)
Net unrealized risk management (gain) loss	**(7)**	15	**12**	(28)
	$ (24)	$ 13	**$ (2)**	$ (35)

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The Company's financial instruments are categorized as Level 1 with the exception of risk management assets and liabilities, which are categorized as Level 2. There were no transfers between Level 1, 2, and 3 financial instruments. The fair values of the Company's fixed rate long-term debt is outlined below:

	Dec 31, 2023	
	Carrying amount	**Level 1 Fair Value**
Fixed rate long-term debt (1) (2)	$ **(10,799)**	$ **(10,795)**

(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 financial statements for the year ended December 31, 2022.

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 December 31, 2023, 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 December 31, 2023, the Company had US$1,003 million of foreign currency forward contracts outstanding (December 31, 2022 – US$1,017 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, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at December 31, 2023, substantially all of the Company's accounts receivable were due within normal trade terms.

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

c) Liquidity risk

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

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

As at December 31, 2023, 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	$ 1,418	$ —	$ —	$ —
Accrued liabilities	$ 3,534	$ —	$ —	$ —
Long-term debt (1)	$ 980	$ 1,584	$ 2,317	$ 5,978
Other long-term liabilities (2)	$ 302	$ 184	$ 428	$ 645
Interest and other financing expense (3)	$ 582	$ 518	$ 1,257	$ 3,362

(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, $298 million; one to less than two years, $184 million; two to less than five years, $428 million; and thereafter, $645 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2023.

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 December 31, 2023:

	2024	2025	2026	2027	2028	Thereafter
Product transportation and processing (1)	$ 1,572	$ 1,595	$ 1,408	$ 1,358	$ 1,242	$ 13,380
North West Redwater Partnership service toll (2)	$ 158	$ 157	$ 139	$ 126	$ 130	$ 4,985
Offshore vessels and equipment	$ 36	$ —	$ —	$ —	$ —	$ —
Field equipment and power	$ 38	$ 25	$ 23	$ 22	$ 22	$ 193
Other	$ 145	$ 111	$ 112	$ 25	$ 26	$ 355

(1) The Company's commitment for the 20-year product transportation agreement on the Trans Mountain Pipeline Expansion 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 $3,011 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

	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
(millions of Canadian dollars, unaudited)	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
Segmented product sales																
Crude oil and NGLs	**4,451**	4,124	**17,375**	20,755	**163**	228	**435**	623	**176**	153	**577**	694	**4,790**	4,505	**18,387**	22,072
Natural gas	**560**	1,234	**2,375**	4,931	**2**	4	**7**	13	**13**	8	**51**	55	**575**	1,246	**2,433**	4,999
Other income and revenue [1]	**5**	19	**10**	217	**—**	(3)	**—**	—	**2**	2	**9**	8	**7**	18	**19**	225
Total segmented product sales	**5,016**	5,377	**19,760**	25,903	**165**	229	**442**	636	**191**	163	**637**	757	**5,372**	5,769	**20,839**	27,296
Less: royalties	**(585)**	(725)	**(2,443)**	(3,918)	**—**	—	**(1)**	(1)	**(18)**	(21)	**(57)**	(71)	**(603)**	(746)	**(2,501)**	(3,990)
Segmented revenue	**4,431**	4,652	**17,317**	21,985	**165**	229	**441**	635	**173**	142	**580**	686	**4,769**	5,023	**18,338**	23,306
Segmented expenses																
Production	**830**	983	**3,617**	3,754	**129**	196	**342**	437	**47**	36	**141**	114	**1,006**	1,215	**4,100**	4,305
Transportation, blending and feedstock	**1,530**	1,505	**5,808**	6,394	**1**	1	**7**	6	**—**	—	**1**	1	**1,531**	1,506	**5,816**	6,401
Depletion, depreciation and amortization	**971**	949	**3,679**	3,595	**466**	1,653	**494**	1,747	**66**	41	**213**	173	**1,503**	2,643	**4,386**	5,515
Asset retirement obligation accretion	**58**	51	**234**	171	**12**	10	**46**	33	**2**	2	**8**	7	**72**	63	**288**	211
Risk management activities (commodity derivatives)	**7**	12	**24**	18	**—**	—	**—**	—	**—**	—	**—**	—	**7**	12	**24**	18
Total segmented expenses	**3,396**	3,500	**13,362**	13,932	**608**	1,860	**889**	2,223	**115**	79	**363**	295	**4,119**	5,439	**14,614**	16,450
Segmented earnings (loss)	**1,035**	1,152	**3,955**	8,053	**(443)**	(1,631)	**(448)**	(1,588)	**58**	63	**217**	391	**650**	(416)	**3,724**	6,856
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange (gain) loss																
Loss (gain) from investments																
Total non-segmented expenses																
Earnings before taxes																
Current income tax																
Deferred income tax																
Net earnings																

	Oil Sands Mining and Upgrading				Midstream and Refining				Inter–segment elimination and other				Total			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
(millions of Canadian dollars, unaudited)	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
Segmented product sales																
Crude oil and NGLs [2]	**5,042**	4,935	**18,661**	20,804	**20**	21	**76**	80	**(23)**	47	**176**	53	**9,829**	9,508	**37,300**	43,009
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**28**	41	**142**	237	**603**	1,287	**2,575**	5,236
Other income and revenue [1]	**3**	(2)	**5**	149	**236**	205	**926**	906	**1**	(4)	**10**	5	**247**	217	**960**	1,285
Total segmented product sales	**5,045**	4,933	**18,666**	20,953	**256**	226	**1,002**	986	**6**	84	**328**	295	**10,679**	11,012	**40,835**	49,530
Less: royalties	**(523)**	(577)	**(2,366)**	(3,242)	**—**	—	**—**	—	**—**	—	**—**	—	**(1,126)**	(1,323)	**(4,867)**	(7,232)
Segmented revenue	**4,522**	4,356	**16,300**	17,711	**256**	226	**1,002**	986	**6**	84	**328**	295	**9,553**	9,689	**35,968**	42,298
Segmented expenses																
Production	**947**	1,017	**3,989**	4,076	**89**	63	**332**	271	**14**	14	**59**	60	**2,056**	2,309	**8,480**	8,712
Transportation, blending and feedstock [2]	**663**	867	**2,563**	2,652	**166**	155	**664**	691	**(11)**	73	**259**	229	**2,349**	2,601	**9,302**	9,973
Depletion, depreciation and amortization	**554**	481	**2,011**	1,822	**4**	5	**16**	16	**—**	—	**—**	—	**2,061**	3,129	**6,413**	7,353
Asset retirement obligation accretion	**19**	19	**78**	70	**—**	—	**—**	—	**—**	—	**—**	—	**91**	82	**366**	281
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**7**	12	**24**	18
Total segmented expenses	**2,183**	2,384	**8,641**	8,620	**259**	223	**1,012**	978	**3**	87	**318**	289	**6,564**	8,133	**24,585**	26,337
Segmented earnings (loss)	**2,339**	1,972	**7,659**	9,091	**(3)**	3	**(10)**	8	**3**	(3)	**10**	6	**2,989**	1,556	**11,383**	15,961
Non-segmented expenses																
Administration													**119**	108	**452**	415
Share-based compensation													**57**	319	**491**	804
Interest and other financing expense													**117**	76	**636**	549
Risk management activities (other)													**(31)**	1	**(26)**	(53)
Foreign exchange (gain) loss													**(265)**	(185)	**(279)**	738
Loss (gain) from investments													**34**	(93)	**(56)**	(196)
Total non-segmented expenses													**31**	226	**1,218**	2,257
Earnings before taxes													**2,958**	1,330	**10,165**	13,704
Current income tax													**505**	399	**1,879**	2,906
Deferred income tax													**(174)**	(589)	**53**	(139)
Net earnings													**2,627**	1,520	**8,233**	10,937

(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]

	Year Ended					
	Dec 31, 2023			Dec 31, 2022		
	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	**$ 41**	**$ (36)**	**$ 5**	$ 28	$ (59)	$ (31)
Offshore Africa	**3**	**—**	**3**	5	—	5
Oil Sands Mining and Upgrading	**—**	**(25)**	**(25)**	—	—	—
	44	**(61)**	**(17)**	33	(59)	(26)
Property, plant and equipment						
Exploration and Production						
North America	**2,729**	**(321)**	**2,408**	3,105	136	3,241
North Sea	**33**	**525**	**558**	126	177	303
Offshore Africa	**169**	**18**	**187**	119	(44)	75
	2,931	**222**	**3,153**	3,350	269	3,619
Oil Sands Mining and Upgrading	**1,894**	**(251)**	**1,643**	1,719	(843)	876
Midstream and Refining	**10**	**—**	**10**	9	(1)	8
Head Office	**30**	**—**	**30**	25	—	25
	4,865	**(29)**	**4,836**	5,103	(575)	4,528
	$ 4,909	**$ (90)**	**$ 4,819**	$ 5,136	$ (634)	$ 4,502

(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

	Dec 31 2023	Dec 31 2022
Exploration and Production		
North America	**$ 30,058**	$ 31,135
North Sea	**602**	378
Offshore Africa	**1,380**	1,322
Other	**32**	54
Oil Sands Mining and Upgrading	**42,865**	42,102
Midstream and Refining	**856**	979
Head Office	**162**	172
	$ 75,955	$ 76,142

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 December 31, 2023:	
Interest coverage (times)	
Net earnings (1)	17.0x
Adjusted funds flow (2)	28.0x

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

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

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CORPORATE INFORMATION

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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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