SECOND QUARTER REPORT

THREE AND SIX MONTHS ENDED JUNE 30, 2022 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2022 SECOND QUARTER RESULTS

Canadian Natural's President, Tim McKay, commented on the Company's second quarter 2022 results "Our world class asset base is strategically balanced across commodity types so we can be flexible and capture opportunities throughout the commodity price cycle to maximize value for our shareholders. A substantial portion of our unique and diverse asset base consists of long life low decline assets which have significant, low risk, high value reserves that require lower maintenance capital than most other reserves, making Canadian Natural a truly robust and resilient energy company.

Our culture of continuous improvement with a focus on cost control and safe, effective and efficient operations, and our disciplined approach to capital allocation continues to drive strong operating results. Total corporate production averaged approximately 1,211 MBOE/d in Q2/22, including record quarterly natural gas production of approximately 2.1 Bcf/d which has grown over 30% from Q2/21 levels. We completed turnarounds at our Oil Sands Mining and Upgrading assets in Q2/22, with both mines having returned to full production rates, capturing a strong Synthetic Crude Oil ("SCO") price premium to WTI.

So far in 2022, we have had strong execution and have realized efficiencies in both of our Conventional E&P and thermal in situ drilling programs, resulting in the drilling program being ahead of forecast in terms of actual versus planned wells drilled year-to-date, with comparable costs on a per well basis. In order to maximize value, we plan to continue with our operational momentum in the second half of 2022 maintaining the same base level of operating drilling rigs (approximately 13) to drill additional Conventional E&P wells beyond our original 2022 forecasted levels, which essentially backfills the latter half of our drilling program. Additionally, as part of our strategic growth plan released in January 2022, we are now targeting to drill 15 additional net thermal in situ wells in 2022. Our updated 2022 base and strategic growth capital program is now targeted to be approximately $4.9 billion and corporate production guidance range is increasing to 1,295 MBOE/d to 1,335 MBOE/d.

Environmental, Social and Governance ("ESG") remains a priority for us as evidenced in our 2021 Stewardship Report to Stakeholders published today. This report highlights several of our ESG achievements, including top tier safety performance and the shared value achieved by working together across Canada with 144 Indigenous-owned businesses by which approximately $572 million in contracts were awarded in 2021, a 17% increase from 2020 levels. Additionally, Canadian Natural is a research and development ("R&D") investment leader. We have increased our R&D investment by 33% over 2020 levels with over $450 million invested in 2021 in technology development and deployment, with a focus of this investment on environmental footprint reduction, including reductions in greenhouse gas ("GHG") emissions, and productivity improvements. The Company’s strong track record of R&D investment will continue in 2022 and beyond and is targeted to grow with our participation in the Pathways Alliance. Working together with the federal and Alberta governments, the Pathways Alliance is a transformative industry collaboration with an actionable plan that will help us collectively be more effective and efficient from a time and cost perspective for Carbon Capture, Utilization and Storage ("CCUS") projects and other GHG reduction projects. The federal government’s support through an investment tax credit as well as the Alberta government’s support in principle are important to achieving ambitious GHG emissions reductions by 2030. The tax credit is a positive approach where industry and government can co-invest in CCUS infrastructure at an achievable pace of 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."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "We are committed to maximizing shareholder value through effective and nimble capital allocation. In Q2/22, Canadian Natural generated approximately $5.4 billion in adjusted funds flow, resulting in significant free cash flow of approximately $3.3 billion, after dividends of approximately $0.9 billion and net base capital expenditures of approximately $1.3 billion, excluding acquisitions and strategic growth capital. We continue to strengthen our balance sheet, having reduced net debt by approximately $1.4 billion in Q2/22, ending the quarter with approximately $12.4 billion in net debt.

Returns to shareholders year-to-date in 2022 have been significant as we have returned approximately $2.4 billion through dividends and approximately $4.0 billion through share repurchases, for a total of $6.4 billion, up to and including August 3, 2022. This includes the 28% increase to our sustainable and growing quarterly dividend in March 2022 to $0.75 per share, marking 2022 as the 22nd consecutive year of dividend increases. The increasing base dividend demonstrates the confidence that the Board of Directors has in the Company's world class assets and its ability to generate significant and sustainable free cash flow through the commodity price cycle.

Our free cash flow allocation policy is unique in that shareholder returns are not impacted by strategic growth capital or acquisitions given our current net debt position is below $15 billion, and that our free cash flow is net of dividends. Through Q3/22, we will continue to target to allocate 50% of our free cash flow to share repurchases and 50% to the balance sheet.

Strong execution across the Company's operations year-to-date has resulted in substantial free cash flow generation driven by our top tier long life low decline assets with low maintenance capital requirements and our low cost structure. As a result, our financial position continues to strengthen, allowing for incremental returns to shareholders. Reflecting this, in August 2022, the Board of Directors approved an increase in returns to shareholders by declaring a special dividend of $1.50 per share, payable on August 31, 2022 to shareholders of record on August 23, 2022. This is a step towards the previously announced target to increase shareholder returns when net debt reaches $8 billion, which the Board of Directors see as a sustainable base level of corporate debt.

When you combine our leading financial results with our top tier asset base, this provides unique competitive advantages which drive material free cash flow generation allowing for significant returns to shareholders."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Jun 30 2022**	 Mar 31 2022	 Jun 30 2021	Six Months Ended **Jun 30 2022**	 Jun 30 2021
Net earnings	**$ 3,502**	$ 3,101	$ 1,551	**$ 6,603**	$ 2,928
Per common share – basic	**$ 3.04**	$ 2.66	$ 1.31	**$ 5.70**	$ 2.47
– diluted	**$ 3.00**	$ 2.63	$ 1.30	**$ 5.63**	$ 2.46
Adjusted net earnings from operations (1)	**$ 3,800**	$ 3,376	$ 1,480	**$ 7,176**	$ 2,699
Per common share – basic (2)	**$ 3.30**	$ 2.90	$ 1.25	**$ 6.20**	$ 2.28
– diluted (2)	**$ 3.26**	$ 2.86	$ 1.24	**$ 6.12**	$ 2.27
Cash flows from operating activities	**$ 5,896**	$ 2,853	$ 2,940	**$ 8,749**	$ 5,476
Adjusted funds flow (1)	**$ 5,432**	$ 4,975	$ 3,049	**$ 10,407**	$ 5,761
Per common share – basic (2)	**$ 4.72**	$ 4.27	$ 2.57	**$ 8.99**	$ 4.86
– diluted (2)	**$ 4.66**	$ 4.21	$ 2.56	**$ 8.87**	$ 4.85
Cash flows used in investing activities	**$ 1,345**	$ 1,251	$ 719	**$ 2,596**	$ 1,367
Net capital expenditures (1), excluding net acquisition costs and strategic growth capital (3)	**$ 1,266**	$ 844	$ 957	**$ 2,110**	$ 1,765
Net capital expenditures (1)	**$ 1,450**	$ 1,455	$ 1,285	**$ 2,905**	$ 2,093
Daily production, before royalties					
Natural gas (MMcf/d)	**2,105**	2,006	1,614	**2,056**	1,606
Crude oil and NGLs (bbl/d)	**860,338**	945,809	872,718	**902,837**	925,741
Equivalent production (BOE/d) (4)	**1,211,147**	1,280,180	1,141,739	**1,245,473**	1,193,434

(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 ended June 30, 2022 dated August 3, 2022.

(2) Non-GAAP Ratio. 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 ended June 30, 2022 dated August 3, 2022.

(3) Net capital expenditures, excluding net acquisition costs and strategic growth capital, is defined as base capital expenditures.

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

- The strength of Canadian Natural's long life low decline asset base, supported by safe, effective and efficient operations makes our business unique, robust and sustainable. In Q2/22, the Company generated strong financial results, including:
  - Net earnings of approximately $3.5 billion and adjusted net earnings from operations of approximately $3.8 billion.
  - Cash flows from operating activities of approximately $5.9 billion.
  - Adjusted funds flow of approximately $5.4 billion.

- Strong execution across the Company's operations year-to-date has resulted in substantial free cash flow[1] generation driven by our top tier long life low decline assets with low maintenance capital requirements and our low cost structure. As a result, our financial position continues to strengthen, allowing for incremental returns to shareholders. In August 2022, the Board of Directors approved an increase in returns to shareholders by declaring a special dividend. Subsequent to quarter end, the Company declared:
  - A special dividend of $1.50 per share, payable on August 31, 2022 to shareholders of record on August 23, 2022.
  - A quarterly base dividend of $0.75 per share, payable on October 5, 2022 to shareholders of record on September 16, 2022. In March 2022, Canadian Natural increased its sustainable and growing quarterly dividend by 28% to $0.75 per share, up from $0.5875 per share, marking 2022 as the 22nd consecutive year of dividend increases.
- Canadian Natural's free cash flow policy is defined as adjusted funds flow less base capital expenditures and dividends, including special dividends. The Company targets to allocate 50% of this free cash flow to share repurchases and 50% to the balance sheet, less any strategic growth capital / acquisitions. In addition, when the Company's net debt reaches $8 billion, which the Board sees as a base level of corporate debt, the Company will allocate additional free cash flow as incremental returns to shareholders.
  - Our policy is unique in that acquisitions and strategic growth capital do not impact returns to shareholders.

Free Cash Flow and Returns to Shareholders

($ millions)	Six Months Ended Jun 30 2022
Adjusted funds flow (1)	$ 10,407
Less: Base capital expenditures (2)	2,110
Dividends paid on common shares	1,560
Free cash flow	**$ 6,737**
Share repurchases	$ 3,088
Percent of free cash flow	46%
Balance sheet / Strategic Growth Capital / acquisitions	$ 3,649
Percent of free cash flow	54%
Total direct returns to shareholders (dividends paid and share repurchases)	**$ 4,648**

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, which are provided in the “Non-GAAP and Other Financial Measures” section of the Company's MD&A for the three months ended June 30, 2022 dated August 3, 2022.

(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 ended June 30, 2022 dated August 3, 2022 for more details on net capital expenditures.

- Canadian Natural delivered substantial free cash flow in Q2/22 of approximately $3.3 billion[2] after approximately $0.9 billion in dividend payments and base capital expenditures[3] of approximately $1.3 billion.
  - Returns to shareholders was significant in Q2/22 having returned approximately 53% of adjusted funds flow or approximately $2.9 billion, comprised of approximately $0.9 billion in dividends and approximately $2.0 billion in share repurchases.
    - In Q2/22, the Company repurchased approximately 26.4 million common shares for cancellation at a weighted average price of $75.92 per share for a total of approximately $2.0 billion.
  - Year-to-date up to and including August 3, 2022, the Company has returned a total approximately $6.4 billion to shareholders through approximately $2.4 billion in dividends and approximately $4.0 billion through share repurchases via the cancellation of approximately 55.9 million common shares at a weighted average price of $71.47 per share.
    - Since 2010, Canadian Natural has repurchased approximately 189.6 million shares for a total of approximately $9.3 billion at a weighted average price of $49.21 per share.
- During Q2/22, the Company continued to strengthen its balance sheet and improve its financial flexibility.

- Increased indirect returns to shareholders by reducing net debt[(1)] by approximately $1.4 billion, ending the quarter with approximately $12.4 billion in net debt.
- Undrawn revolving bank credit facilities totaling approximately $5.5 billion were available at June 30, 2022. Including cash and cash equivalents and short-term investments, the Company had significant liquidity[(1)] of approximately $6.1 billion with no amounts drawn under its commercial paper program.
- On June 3, 2022, DBRS upgraded our unsecured long-term investment grade credit rating to A (low) from BBB (high), with a stable rating outlook.

▪ In Q2/22, the Company continued its focus on safe, effective and efficient operations, delivering quarterly average production volumes of 1,211,147 BOE/d.

- Canadian Natural delivered record quarterly average natural gas production of 2,105 MMcf/d in Q2/22, increases of approximately 5% and 30% over Q1/22 and Q2/21 levels respectively. The increase over Q1/22 reflects strong drilling results, partially offset by natural field declines. The increase over Q2/21 levels reflects strong drilling results and acquisitions, partially offset by natural field declines.
  - As a result of the Company's diversified sales points, our natural gas production captured strong realized natural gas pricing of $7.93/Mcf in Q2/22, a 51% increase above Q1/22 levels and approximately 30% higher than the AECO benchmark price in Q2/22.
  - Corporate natural gas operating costs[(4)] averaged $1.17/Mcf in Q2/22, decreases of 11% and 2% from Q1/22 and Q2/21 levels respectively, primarily reflecting seasonality impact and higher production volumes in Q2/22.
- Quarterly liquids production averaged 860,338 bbl/d in Q2/22, a 9% decrease from Q1/22 levels and comparable to Q2/21 levels. The decrease from Q1/22 primarily reflects the planned turnaround activities in Q2/22 on the Company's Oil Sands Mining and Upgrading assets, which reduced production by approximately 73,000 bbl/d in Q2/22.
  - The Company's world class Oil Sands Mining and Upgrading assets continue to deliver safe and reliable production, with Horizon reaching royalty payout in April 2022. Quarterly production averaged 356,953 bbl/d of SCO in Q2/22, reflecting planned turnarounds at Horizon and Scotford completed during the quarter.
    - The turnaround at Horizon was completed in 24 days, 8 days earlier than budgeted, primarily as a result of strong execution.
    - The turnaround at the non-operated Scotford Upgrader was completed in 82 days, 17 days longer than budgeted.
    - With the turnarounds now complete, both AOSP and Horizon have returned to full production rates, capturing a strong SCO price premium of over US$10/bbl to WTI.

(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 ended June 30, 2022 dated August 3, 2022.

(2) Based on sum of rounded numbers.

(3) 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 ended June 30, 2022 dated August 3, 2022 for more details on net capital expenditures.

(4) Calculated as production expense divided by respective sales volumes. Natural gas and natural gas liquids production volumes approximate sales volumes.

UPDATE TO 2022 CAPITAL BUDGET AND PRODUCTION

- Canadian Natural has had strong execution with its drilling program so far in 2022, resulting in the Company drilling 22 net operated wells ahead of forecast, consisting of 11 net thermal in situ and 11 net Conventional E&P wells, with drilling costs on a per well basis comparable to budget, despite inflationary cost pressures. As a result, the Company has the ability to capture additional value by accelerating strategic growth opportunities within our large, unique and diverse asset base to maximize value for our shareholders. As a result, 2022 capital expenditures will be adjusted as follows:
  - Base Capital will now be targeted at approximately $3,845 million, an increase of approximately $200 million over original 2022 levels, largely due to forecasted inflationary pressures in all operating areas for items such as steel, manufactured goods, services and labour.
  - Strategic Growth Capital will now be targeted at approximately $1,075 million, an increase of approximately $375 million over original 2022 levels, with details of the Company's additional high value opportunities summarized below.
- Updated 2022 capital expenditures are summarized as follows:

Net Capital Expenditures ($ million)[(1)]	**2022 Budget**	**2022 Forecast**
Base Capital[(2)]	$ 3,645	$ 3,845
Strategic Growth Capital	700	1,075
Total Capital	**$ 4,345**	**$ 4,920**

(1) Excludes net acquisition costs.

(2) Net capital expenditures, excluding net acquisition costs and strategic growth capital, is defined as base capital expenditures.

- As a result of efficiencies gained and this incremental Strategic Growth Capital in 2022, we are targeting to add approximately 40,000 BOE/d of additional production growth in 2023 from the original 2022 mid-point of guidance.

Strategic Growth Plan – Incremental Targeted Production	**2023 Forecast**	**2025 Forecast**
Natural gas (MMcf/d)	~140	~280
Conventional E&P Crude Oil & NGLs (bbl/d)	~10,000	~35,500
Thermal and Oil Sands Mining & Upgrading (bbl/d)	~7,000	~14,000
Total Liquids (bbl/d)	~17,000	~49,500
Total BOE/d	**~40,000**	**~96,000**

- The incremental Strategic Growth Capital is targeted to be invested, as follows:
  - Canadian Natural targets to drill an additional 41 net Conventional E&P wells, which essentially backfills the latter half of the drilling program at a cost of approximately $180 million, which includes pipelines, facilities and additional non-operated activity.
    - As part of this Strategic Growth Capital, the Company will be investing additional capital to delineate its large, undeveloped Clearwater land base of approximately 940,000 net acres, one of the largest land bases of Clearwater rights. Drilling success on our Clearwater rights has resulted in current production from these lands in excess of 10,000 bbl/d, up from 3,900 bbl/d at the start of 2022.
  - As part of our original thermal in situ strategic growth plan released in January 2022 and as a result of efficiencies realized to date, the Company is targeting to drill in 2022 an additional 15 net in situ wells, originally targeted for 2023, totaling approximately $45 million in capital spend, which includes pipelines and facilities.
  - In Oil Sands Mining and Upgrading, the Company targets to add additional shovels and tailings pipe at Horizon, for total incremental Strategic Growth Capital of approximately $70 million.
  - In addition, the following incremental Strategic Growth Capital expenditures in the second half of 2022 are targeted to maintain efficiencies into 2023 and beyond:
    - Primarily long leads for Baobab production drilling in Offshore Africa, totaling approximately $10 million.

  - Progress engineering and long leads for 2 thermal in situ pad additions at Pike, targeting to add approximately 28,000 bbl/d of peak capacity in 2026, totaling approximately $15 million.
  - Progress liquids rich Montney natural gas projects that add capacity of approximately 140 MMcf/d of natural gas and 25,500 bbl/d of liquids in future years, totaling approximately $55 million.
    - Farrell Creek Gas Plant targets to add capacity of approximately 70 MMcf/d of natural gas and approximately 7,000 bbl/d of liquids with an on-stream target of July 2023.
    - Knopcik Gas Plant targets to add capacity of approximately 70 MMcf/d of natural gas and approximately 18,500 bbl/d of liquids with an on-stream target of November 2024.
- As a result of strong execution to date in 2022, production guidance is increasing to range between 1,295 MBOE/d to 1,335 MBOE/d, which includes a 5% increase to natural gas from budgeted levels with comparable total liquids.
  - Conventional E&P annual production growth in 2022 is targeted to increase by approximately 85,000 BOE/d or 16% from 2021 average production volumes.
- Updated 2022 targeted production guidance is summarized as follows:

Daily Production Volumes (before royalties)	**2022 Budget**	**2022 Forecast**
Natural gas (MMcf/d)	1,980 – 2,030	2,095 – 2,120
Conventional E&P Crude Oil & NGLs (Mbbl/d)	250 – 267	256 – 267
Thermal and Oil Sands Mining & Upgrading (Mbbl/d)(1)	690 – 715	690 – 715
Total Liquids (Mbbl/d)	940 – 982	946 – 982
Total MBOE/d	**1,270 – 1,320**	**1,295 – 1,335**

(1) Reflects planned downtime for turnaround activities at Horizon, Scotford and Canadian Natural's 70% ownership in the AOSP.

Note: See Advisory for cautionary statements, definitions, pricing assumptions and Non-GAAP and other financial measure disclosure.

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 78% of total forecasted liquids production in 2022, 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 long life low decline production comes from Canadian Natural's top tier thermal in situ oil sands operations and the Company's 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, by owning and operating most of the related infrastructure, Canadian Natural is able to control major components of the Company's operating costs and minimize production commitments. Low capital exposure projects can be quickly stopped or started depending upon success, market conditions or corporate needs.

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

Drilling Activity	Six Months Ended June 30			
	2022		2021	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil (1)	**142**	**139**	73	71
Natural gas	**65**	**43**	38	31
Dry	**1**	**1**	—	—
Subtotal	**208**	**183**	111	102
Stratigraphic test / service wells	**463**	**395**	396	329
Total	**671**	**578**	507	431
Success rate (excluding stratigraphic test / service wells)		**99%**		100%

(1) Includes bitumen wells.

- The Company drilled a total of 183 net crude oil and natural gas wells in the first six months of 2022 compared to 102 in the first six months of 2021, an increase of 81 net wells over this time period.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Crude oil and NGLs production (bbl/d)	**227,540**	222,537	219,763	**225,052**	215,508
Net wells targeting crude oil	**39**	44	22	**83**	61
Net successful wells drilled	**38**	44	22	**82**	61
Success rate	**97%**	100%	100%	**99%**	100%

- As part of the Company's updated capital forecast, due to efficiencies realized and continuation of our level loaded schedule, Canadian Natural targets to drill an additional 25 Conventional E&P crude oil wells above its original budgeted plans, which essentially backfills the latter half of the drilling program. Details are as follows:
  - At Pelican Lake, the Company targets to drill 8 net crude oil wells, all incremental from budgeted levels.
  - The Company targets to drill an additional 7 primary heavy crude oil wells from its original budgeted levels, now totaling 168 net crude oil wells.
  - The Company targets to drill an additional 10 net light crude oil wells from its original budgeted levels, now totaling 39 net crude light oil wells.
- North America E&P liquids production, excluding thermal in situ, averaged 227,540 bbl/d in Q2/22, increases of 2% and 4% over Q1/22 and Q2/21 levels respectively. The increase over Q1/22 primarily reflects strong drilling results, partially offset by natural field declines. The increase over Q2/21 primarily reflects strong drilling results as well as acquisitions, partially offset by natural field declines.
  - Primary heavy crude oil production averaged 66,521 bbl/d in Q2/22, a 5% increase from Q1/22 levels and comparable to Q2/21. The increase in production from Q1/22 is primarily a result of strong drilling results, partially offset by natural field declines.
    - Operating costs(1) in the Company's primary heavy crude oil operations averaged $22.86/bbl (US$17.90/bbl) in Q2/22, an increase of 4% over Q1/22 levels, primarily due to increased trucking related costs.
    - At Smith, in the Clearwater primary heavy crude oil play, Canadian Natural drilled 12 horizontal multilateral wells on 4 pads in Q2/22. Current production from these wells is approximately 4,400 bbl/d with a strong capital efficiency(2) of approximately $6,300/BOE/d. The Company has now drilled a total of 19 wells in the Clearwater play in 2022, with total Company Clearwater production now in excess of 10,000 bbl/d, up from approximately 3,900 bbl/d at the start of 2022.
      - As part of this Strategic Growth Capital, the Company will be investing additional capital to delineate its large, undeveloped Clearwater land base of approximately 940,000 net acres, one of the largest land bases of Clearwater rights.
  - Pelican Lake production averaged 51,112 bbl/d in Q2/22, comparable to Q1/22 levels and a 7% decrease from Q2/21, reflecting the low decline nature of this long life asset and the continued success of this world class polymer flood.
    - Operating costs at Pelican Lake averaged $7.99/bbl (US$6.26/bbl) in Q2/22, a 7% increase from Q1/22 levels, primarily as a result of higher lease maintenance costs due to abnormally wet spring conditions.
  - North America light crude oil and NGL production averaged 109,907 bbl/d in Q2/22, increases of 2% and 12% over Q1/22 and Q2/21 levels respectively. The increase over Q1/22 is primarily a result of strong drilling results, partially offset by natural field declines. The increase over Q2/21 is primarily a result of strong drilling results as well as acquisitions, partially offset by natural field declines.
    - Operating costs in the Company's North America light crude oil and NGL areas averaged $15.19/bbl (US$11.90/bbl) in Q2/22, comparable to Q1/22 levels.

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

(2) Supplementary financial measure. Refer to the "Non-GAAP and Other Financial Measures" section of this press release.

- At Wembley, the Company brought 9 liquids-rich Montney wells on production in late Q1/22 and Q2/22 at a top tier capital efficiency of approximately $3,400/BOE/d. July monthly production from these wells is exceeding budgeted rates, at approximately 8,200 bbl/d of liquids and 27 MMcf/d of natural gas, maximizing existing facility capacity.
- At Karr, the Company brought 4 gross (3.4 net) Dunvegan light crude oil wells on production in March 2022 at a strong capital efficiency of approximately $5,200/BOE/d. July monthly production from these wells is exceeding budgeted rates, at approximately 2,900 bbl/d of liquids and 3 MMcf/d of natural gas.

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Bitumen production (bbl/d)	**249,938**	261,743	258,551	**255,808**	263,016
Net wells targeting bitumen	**45**	12	4	**57**	7
Net successful wells drilled	**45**	12	4	**57**	7
Success rate	**100%**	100%	100%	**100%**	100%

- Canadian Natural utilized 4 drilling rigs on its thermal in situ assets, which were ahead of budgeted pace by 11 net wells as of the end of Q2/22 due to strong execution. As part of our original thermal in situ strategic growth plan released in January 2022 and as a result of efficiencies realized to date, the Company is targeting to drill in 2022 an additional 15 net in situ wells, originally targeted for 2023, totaling approximately $45 million in capital spend, which includes pipelines and facilities. The Company now targets to drill a total of 117 net in situ wells in 2022.
  - Additionally, as part of our capital update, the Company is targeting to progress engineering and long leads for 2 thermal in situ pad additions at Pike, targeting to add approximately 28,000 bbl/d of capacity by 2026.
  - Capital efficiencies average approximately $8,000/BOE/d on Steam Assisted Gravity Drainage ("SAGD") pads and approximately $10,000/BOE/d on Cyclic Steam Stimulation ("CSS") pads.
- Canadian Natural's thermal in situ assets continued to demonstrate how the strength of the Company's long life low decline assets drive long term shareholder value. Production averaged 249,938 bbl/d in Q2/22, decreases of 5% and 3% from Q1/22 and Q2/21 levels respectively, primarily reflecting planned turnaround activities at Kirby South.
  - Thermal in situ operating costs averaged $18.93/bbl (US$14.83/bbl) in Q2/22, an increase of 32% over Q1/22 levels, primarily reflecting higher energy costs.
- Canadian Natural has been piloting solvent enhanced oil recovery technology on certain of its thermal in situ assets with an objective to increase bitumen production, reduce the Steam to Oil Ratio ("SOR"), reduce GHG intensity and realize high solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
  - The Company is progressing with engineering and design of a commercial scale solvent SAGD pad development at Kirby North, which is targeted to commence solvent injection in early 2024.
  - Canadian Natural's second solvent pilot is in the Primrose steam flood area began solvent injection in November 2021 with plans to continue for approximately two years to achieve targeted SOR and GHG intensity reductions of 40% to 45%, with solvent recoveries of greater than 70%. The Company is seeing positive operating results to date, including SOR reductions of approximately 50%.

North America Natural Gas

	Three Months Ended			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Natural gas production (MMcf/d)	**2,089**	1,988	1,594	**2,039**	1,589
Net wells targeting natural gas	**20**	23	9	**43**	31
Net successful wells drilled	**20**	23	9	**43**	31
Success rate	**100%**	100%	100%	**100%**	100%

- Canadian Natural had, as at December 31, 2021, the largest reported natural gas reserves in Canada with a proved and proved plus probable basis of approximately 12.2 Tcf and 20.2 Tcf respectively. These reserves provide the Company with significant high value growth opportunities for the Company and supports long-term shareholder value.
- As part of the Company's updated capital budget, due to efficiencies realized and continuation of our level loaded schedule, Canadian Natural targets to drill additional Conventional E&P wells, which essentially backfills the latter half of the drilling program, resulting in an increase of 16 net natural gas wells from budgeted levels, totaling 70 net natural gas wells targeted in 2022.
  - Corporate 2022 annual natural gas production guidance has been increased to record levels, now targeted to range from 2,095 MMcf/d to 2,120 MMcf/d, an increase of 5% at the mid-point from original 2022 budgeted levels.
    - Strong results and incremental capital in 2022 targets to increase annual production this year by approximately 105 MMcf/d from original 2022 budgeted levels.
- Canadian Natural achieved record quarterly North America natural gas production in Q2/22, averaging approximately 2,089 MMcf/d, increases of 5% and 31% over Q1/22 and Q2/21 levels respectively. The increase over Q1/22 levels primarily reflects strong drilling results, partially offset by natural field declines. The increase over Q2/21 levels primarily reflects strong drilling results and acquisitions, partially offset by natural field declines.
  - As a result of the Company's diversified sales points, our natural gas production captured strong realized natural gas pricing of $7.93/Mcf in Q2/22, a 51% increase above Q1/22 levels and approximately 30% higher than the AECO benchmark price in Q2/22.
  - North America natural gas operating costs averaged $1.15/Mcf in Q2/22, a 10% decrease from Q1/22 levels, primarily reflecting the seasonality impact, and comparable to Q2/21 levels.
- Within Canadian Natural's liquids-rich Montney area, the Company continues to utilize its efficient low cost drill-to-fill strategy to maximize production volumes.
  - At Townsend, the Company brought a 6 well pad on production in Q2/22 at a strong capital efficiency of approximately $4,500/BOE/d with total July monthly production of approximately 54 MMcf/d.
  - At Edson, the Company brought 3 wells on production late in Q1/22 at top tier capital efficiency of approximately $2,800/BOE/d, with total July monthly production of approximately 32 MMcf/d and 560 bbl/d of liquids.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Crude oil production (bbl/d)	**25,907**	31,703	32,697	**28,789**	32,258
Natural gas production (MMcf/d)	**16**	18	20	**17**	17
Net wells targeting crude oil	**—**	—	1.0	**—**	3.0
Net successful wells drilled	**—**	—	1.0	**—**	3.0
Success rate	**—%**	—%	100%	**—%**	100%

- International E&P crude oil production volumes averaged 25,907 bbl/d in Q2/22, down 18% and 21% from Q1/22 and Q2/21 levels respectively, reflecting unplanned maintenance in the North Sea in Q2/22 together with natural field declines.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Synthetic crude oil production (bbl/d) (1)(2)	**356,953**	429,826	361,707	**393,188**	414,959

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

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

- The Company's world class Oil Sands Mining and Upgrading assets continue to deliver safe and reliable production, with Horizon reaching royalty payout in April 2022. Quarterly production averaged 356,953 bbl/d of SCO in Q2/22, reflecting planned turnarounds at Horizon and Scotford completed during the quarter.
  - The turnaround at Horizon was completed in 24 days, 8 days earlier than budgeted primarily as a result of strong execution.
  - The turnaround at the non-operated Scotford Upgrader was completed in 82 days, 17 days longer than budgeted primarily as a result of longer execution.
  - With the turnarounds now complete, both AOSP and Horizon have returned to full production rates, capturing a strong SCO price premium of over US$10/bbl to WTI.
  - The Horizon and Scotford turnarounds, together with higher energy costs, resulted in Q2/22 operating costs averaging $33.76/bbl (US$26.44/bbl) of SCO.
- At Horizon, the reliability enhancement project is progressing as planned, with planned tie-in activities completed during the turnaround. Construction of additional Vacuum Distillation Unit ("VDU") and Diluent Recovery Unit ("DRU") furnaces is progressing on schedule, with completion targeted in stages in 2023 and 2024.
  - This project is part of the 2022 budgeted Strategic Growth Capital and is targeted to extend the major maintenance cycle from once per year to once every second year, increasing the capacity of zero decline, high value production by approximately 5,000 bbl/d of SCO in 2023, increasing to approximately 14,000 bbl/d of SCO in 2025.
  - As a part of the capital update, the Company targets to add additional shovels and tailings pipe at Horizon supporting the reliability project, for total incremental Strategic Growth Capital of approximately $70 million.
- As budgeted, front end engineering for the In-Pit Extraction Plant ("IPEP") demonstration plant is complete and the Company is now progressing on detailed design work of the 750t/hr commercial unit that will provide dry stackable tailings directly in the mine-pit, targeting to reduce GHG emissions and tailings ponds in the future.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) [1]	**$ 108.42**	$ 94.38	$ 66.06	**$ 101.44**	$ 61.95
WCS heavy differential as a percentage of WTI (%) [2]	**12%**	15%	17%	**14%**	19%
SCO price (US$/bbl)	**$ 114.35**	$ 93.05	$ 66.49	**$ 103.76**	$ 60.43
Condensate benchmark pricing (US$/bbl)	**$ 108.35**	$ 96.16	$ 66.39	**$ 102.29**	$ 62.22
Average realized pricing before risk management (C$/bbl) [3][4]	**$ 115.26**	$ 93.54	$ 61.20	**$ 104.27**	$ 56.87
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 5.95**	$ 4.35	$ 2.70	**$ 5.15**	$ 2.74
Average realized pricing before risk management (C$/Mcf) [4]	**$ 7.93**	$ 5.26	$ 3.17	**$ 6.63**	$ 3.29

(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 this press release and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended June 30, 2022 dated August 3, 2022.

- Canadian Natural has many strengths when marketing its products, including a balanced and diverse product mix of natural gas, conventional heavy crude oil, conventional light crude oil, thermal in situ and SCO.
- Crude oil prices increased significantly in the first six months of 2022, due to lower global crude oil inventories and further impacted by the Russian invasion of Ukraine and the decision by OPEC+ to adhere to previously agreed upon production cuts. Additionally, global economic conditions and outlook continued to improve as the effects of COVID-19 became less impactful on the global economy. WTI averaged US$108.42/bbl in Q2/22, up 15% and 64% from Q1/22 and Q2/21 levels respectively.
- SCO is currently trading at a price premium of over US$10/bbl to WTI reflecting the increased North American demand for refined products as well as partial upgrader outages. Q2/22 SCO price premium was also strong at a US$5.93/bbl premium to WTI, which was also supported by lower volumes in western Canada due to maintenance at oil sands facilities.
- Increased market egress from western Canada and relatively low storage levels has resulted in a more balanced market for heavy crude oil leading to less pricing volatility and stronger WCS pricing.
  - The WCS heavy oil differential as a percentage of WTI averaged 12% in Q2/22, compared to 17% in Q2/21, as a result of improved western Canadian egress and increased demand due to seasonal conditions.
- Natural gas prices continued to strengthen in Q2/22, with AECO averaging $5.95/GJ, reflecting the increase to the NYMEX North American benchmark price, lower storage levels and increased US Liquefied Natural Gas exports.
  - As a result of the Company's diversified sales points, our natural gas production captured strong realized natural gas pricing of $7.93/Mcf in Q2/22, a 51% increase above Q1/22 levels and approximately 30% higher than the AECO benchmark price in Q2/22.
    - Canadian Natural's targeted diversified sales points includes the use of approximately 41% of its total corporate natural gas production in its operations, with approximately 37% targeted to be exported to other North American markets and sold internationally. The remaining 22% would be is sold at AECO/Station 2 pricing.
- Strong performance at the North West Redwater ("NWR") Refinery continues to increase local demand for heavy crude oil, with production of ultra-low sulphur diesel and other refined products averaging 75,418 BOE/d (18,855 BOE/d to the Company) in Q2/22.

- Canadian Natural has been a supporter of incremental pipeline projects, to ensure Canadian crude oil and natural gas can reach the world markets. It is important to have global market access to deliver the most responsible and leading ESG preferred barrels that the world needs.
    - As per the latest public update provided by Trans Mountain Corporation on February 18, 2022, construction of the 590,000 bbl/d Trans Mountain Pipeline Expansion, on which Canadian Natural has committed 94,000 bbl/d, is targeted to be mechanically complete in Q4/23.

FINANCIAL REVIEW

The Company continues to implement proven strategies including its disciplined approach to capital allocation. As a result, the financial position of Canadian Natural remains strong. Canadian Natural's adjusted funds flow generation, credit facilities, US commercial paper program, access to capital markets, diverse asset base and related flexible capital expenditure program, all support a strong financial position and provide the appropriate financial resources for the near-, mid- and long-term.

- Safe, effective and efficient operations combined with our high quality, long life low decline asset base generated substantial quarterly free cash flow of approximately $3.3 billion after dividend payments of approximately $0.9 billion and base capital expenditures of approximately $1.3 billion (excluding net acquisitions and strategic growth capital as per the Company's free cash flow allocation policy).
- Direct returns to shareholders in Q2/22 were strong, totaling approximately $2.9 billion, comprised of approximately $0.9 billion of dividends and approximately $2.0 billion of share repurchases.
    - Canadian Natural increased its sustainable and growing quarterly dividend in March 2022 by 28% to $0.75 per share, up from $0.5875 per share, marking 2022 as the 22nd consecutive year of dividend increases.
    - In March 2022, the Board of Directors approved the renewal and increase of our NCIB so that Canadian Natural can repurchase for cancellation up to 10% of the public float during the 12 month period commencing March 11, 2022 and ending March 10, 2023.
    - In Q2/22, the Company repurchased a total of approximately 26.4 million common shares for cancellation at a weighted average price of $75.92 per share for a total of approximately $2.0 billion.
- Year-to-date up to and including August 3, 2022, the Company has returned approximately $6.4 billion to shareholders through approximately $2.4 billion in dividends and $4.0 billion from the repurchase and cancellation of approximately 55.9 million common shares.
    - Subsequent to quarter end, the Company declared a special dividend of $1.50 per share, payable on August 31, 2022 to shareholders of record on August 23, 2022 and a quarterly dividend of $0.75 per share, payable on October 5, 2022 to shareholders of record on September 16, 2022.
- During Q2/22, the Company continued to strengthen its balance sheet and improve its financial flexibility.
    - Increased indirect returns to shareholders by reducing net debt by approximately $1.4 billion, ending the quarter with approximately $12.4 billion in net debt.
    - On June 3, 2022, DBRS upgraded our unsecured long-term investment grade credit rating to A (low) from BBB (high), with a stable rating outlook.
    - The Company repaid through market purchases $139 million of medium-term notes with interest rates ranging from 1.45% to 3.55%, originally due between 2023 and 2028.
        - Subsequent to June 30, 2022, the Company repaid through market purchases an additional $101 million of medium-term notes.
    - Undrawn revolving bank credit facilities totaling approximately $5.5 billion were available at June 30, 2022. Including cash and cash equivalents and short-term investments, the Company had significant liquidity of approximately $6.1 billion. At June 30, 2022, the Company had no amount drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
- Canadian Natural's free cash flow allocation policy states that when net debt is below $15 billion, 50% of free cash flow will be allocated to share repurchases and 50% of free cash flow to the balance sheet less strategic growth / acquisition opportunities. Free cash flow for the purpose of the policy is defined as adjusted funds flow less dividends, which includes special dividends, less base capital. When net debt is below $8 billion, which the Board sees as a base level of corporate net debt, the free cash flow allocation split will be adjusted to allocate additional free cash flow to shareholders.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE HIGHLIGHTS

Canada and Canadian Natural are well positioned to deliver responsibly produced energy that the world needs through leading ESG performance. Canadian Natural's culture of continuous improvement provides a significant advantage and results in ongoing enhancements to the Company's environmental performance.

Sustainability Reporting

Canadian Natural has been producing its sustainability report, the Stewardship Report to Stakeholders, since 2004 to report on the Company's ongoing commitment to environmental performance, social responsibility and continuous improvement. Canadian Natural has published its 2021 report in conjunction with Q2/22 results, which is now available on the Company's website at www.cnrl.com. This report displays how Canadian Natural continues to focus on safe, reliable effective and efficient operations while minimizing its environmental footprint. It provides a performance overview across the full range of the Company's operations in Western Canada, the UK portion of the North Sea and Offshore Africa.

The Company aligns its reporting with recommendations from the Task Force on Climate-Related Financial Disclosures, the reporting framework from the Sustainability Accounting Standards Board and the Global Reporting Initiative. Canadian Natural's 2021 report includes independent third party reasonable assurance on our scope 1 and 2 emissions (including methane emissions) and limited assurance on our scope 3 emissions.

Highlights from the 2021 report include:

- 49% reduction in the Company's corporate total recordable injury frequency ("TRIF") and a 67% reduction in corporate lost time incident ("LTI") frequency from 2017 to 2021.
- Invested approximately $450 million in technology development and deployment and approximately $84 million on GHG technology and implementation projects in 2021.
- Canadian Natural continues to lower its corporate direct GHG emissions intensity with a 13% reduction from 2017 to 2021.
- 45% reduction in 2021 in the Company's absolute methane emissions in its North American E&P operations from its 2016 baseline.
- 57% reduction in 2021 in the Company's in situ fresh water use intensity from 2017.
- 48% reduction in 2021 in the Company's oil sands mining fresh river water use intensity from 2017.
- Abandoned 3,079 inactive wells and received 889 reclamation certificates in 2021.
- Awarded approximately $572 million in contracts with local indigenous businesses in 2021.

Pathways Alliance

On June 16, 2022, Canada's major oil sands producers announced the combination of three existing industry groups, all focused on responsible development, into a single organization called the Pathways Alliance. The new organization incorporates the Oil Sands Pathways to Net Zero Alliance, launched in 2021, Canada's Oil Sands Innovation Alliance ("COSIA"), created in 2012, and the Oil Sands Community Alliance ("OSCA"), created in 2013.

The six major oil sands companies in the Pathways Alliance, including Canadian Natural, operate approximately 95% of Canada's oil sands production. The goal of this unique alliance is to support Canada in meeting its climate commitments and position Canada to be the preferred source of crude oil globally. Working collectively with the federal and Alberta governments, the Pathways Alliance has a goal to achieve net zero GHG emissions from oil sands operations by 2050 and is pursuing realistic and workable solutions to help address the challenge of climate change and significantly reduce oil sands emissions. The companies involved look forward to continuing to work with governments and to engage with Indigenous and local communities in northern Alberta, to make this ambitious, major emissions-reduction vision a reality so those communities can continue to benefit from Canadian resource development.

Achieving the group's goals will require multiple technology pathways, which includes a foundational project to build a major CCUS system and transportation line connecting oil sands facilities in the Fort McMurray, Christina Lake and Cold Lake regions of Alberta to a carbon storage hub near Cold Lake. As part of securing carbon sequestration tenure for the Pathways foundational project, a project proposal was submitted by the Pathways Alliance to the Government of Alberta for a proposed carbon storage hub located in the Cold Lake region.

Through the Company's participation in the Pathways Alliance with our industry partners and collaboration with the federal and Alberta governments, Canadian Natural is further refining its goal by targeting to achieve net zero emissions in its oil sands operations by 2050.

Government Support for Carbon Capture, Utilization and Storage

The Government of Canada's 2022 budget was released on April 7, 2022, which included an investment tax credit for CCUS projects for industries across Canada. The Government of Alberta has indicated support in principle for CCUS projects. The tax credit is a positive step forward in the Company and industry's efforts to work collaboratively with governments to support Canada in achieving its climate and economic growth objectives.

Canadian Natural is a leader in CCUS and GHG reduction projects and sees many opportunities for industry to advance investments in CCUS projects. That said, CCUS infrastructure will result in long-term incremental costs to the Company and industry's operations. The announced tax credit is a positive approach whereby industry and government can co-invest in infrastructure at an achievable pace of development. Implementation details of the investment tax credit are important and the Company looks forward to understanding how it can be applied to Canadian Natural's projects. However, the recent Environment and Climate Change Canada discussion paper on the proposed GHG emissions cap for the oil and natural gas sector relies on regulated, unrealistic targets to achieve reductions. 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.

Environmental Targets

As previously announced, Canadian Natural has committed to the following environmental targets:

- 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.

ADVISORY

Special Note Regarding non-GAAP and Other Financial Measures

This press release includes references to non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure. These financial measures are used by the Company to evaluate its financial performance, financial position 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 ended June 30, 2022, dated August 3, 2022.

Free Cash Flow

Free cash flow is a non-GAAP financial measure that represents adjusted funds flow adjusted for base capital expenditures and dividends on common shares. 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.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Adjusted funds flow [(1)]	**$ 5,432**	$ 4,975	$ 3,049	**$ 10,407**	$ 5,761
Less: Base capital expenditures [(2)]	**1,266**	844	957	**2,110**	1,765
Dividends on common shares	**871**	689	557	**1,560**	1,060
Free cash flow	**$ 3,295**	$ 3,442	$ 1,535	**$ 6,737**	$ 2,936

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, which are provided in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended June 30, 2022 dated August 3, 2022.

(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 ended June 30, 2022 dated August 3, 2022 for more details on net capital expenditures.

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.

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.

ADVISORY

Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to 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 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 timing and impact of the Oil Sands Pathways to Net Zero ("Pathways") initiative, 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 effects of the novel coronavirus ("COVID-19") pandemic, the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+") and rising inflation rates) 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 and natural gas and NGLs prices including due to actions of OPEC+ taken in response to COVID-19 or otherwise; 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; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; 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 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 (including any production curtailments mandated by the Government of Alberta); 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 and six months ended June 30, 2022 and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2021. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s financial statements for the three and six months ended June 30, 2022 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalties" or "company gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO. Production on an "after royalties" or "company net" basis is also presented for information purposes only.

The following discussion and analysis refers primarily to the Company's financial results for the three and six months ended June 30, 2022 in relation to the comparable periods in 2021 and the first quarter of 2022. 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, 2021, is available on SEDAR at www.sedar.com, 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 August 3, 2022.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Jun 30 2022	Three Months Ended Mar 31 2022	Three Months Ended Jun 30 2021	Six Months Ended Jun 30 2022	Six Months Ended Jun 30 2021
Product sales [1]	**$ 13,812**	$ 12,132	$ 7,124	**$ 25,944**	$ 14,143
Crude oil and NGLs	**$ 11,727**	$ 10,773	$ 6,382	**$ 22,500**	$ 12,670
Natural gas	**$ 1,605**	$ 1,002	$ 509	**$ 2,607**	$ 1,064
Net earnings	**$ 3,502**	$ 3,101	$ 1,551	**$ 6,603**	$ 2,928
Per common share – basic	**$ 3.04**	$ 2.66	$ 1.31	**$ 5.70**	$ 2.47
– diluted	**$ 3.00**	$ 2.63	$ 1.30	**$ 5.63**	$ 2.46
Adjusted net earnings from operations [2]	**$ 3,800**	$ 3,376	$ 1,480	**$ 7,176**	$ 2,699
Per common share – basic [3]	**$ 3.30**	$ 2.90	$ 1.25	**$ 6.20**	$ 2.28
– diluted [3]	**$ 3.26**	$ 2.86	$ 1.24	**$ 6.12**	$ 2.27
Cash flows from operating activities	**$ 5,896**	$ 2,853	$ 2,940	**$ 8,749**	$ 5,476
Adjusted funds flow [2]	**$ 5,432**	$ 4,975	$ 3,049	**$ 10,407**	$ 5,761
Per common share – basic [3]	**$ 4.72**	$ 4.27	$ 2.57	**$ 8.99**	$ 4.86
– diluted [3]	**$ 4.66**	$ 4.21	$ 2.56	**$ 8.87**	$ 4.85
Cash flows used in investing activities	**$ 1,345**	$ 1,251	$ 719	**$ 2,596**	$ 1,367
Net capital expenditures [2]	**$ 1,450**	$ 1,455	$ 1,285	**$ 2,905**	$ 2,093

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

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

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

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings and Adjusted Net Earnings from Operations

Net earnings for the six months ended June 30, 2022 were $6,603 million compared with $2,928 million for the six months ended June 30, 2021. Net earnings for the six months ended June 30, 2022 included non-operating items, net of tax, of $573 million compared with $229 million for the six months ended June 30, 2021 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the loss (gain) from investments, the impact of the settlement of the cross currency swap, and government grant income under the provincial well-site rehabilitation programs. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2022 were $7,176 million compared with $2,699 million for the six months ended June 30, 2021.

Net earnings for the second quarter of 2022 were $3,502 million compared with $1,551 million for the second quarter of 2021 and $3,101 million for the first quarter of 2022. Net earnings for the second quarter of 2022 included non-operating items, net of tax, of $298 million compared with $71 million for the second quarter of 2021 and $275 million for the first quarter of 2022 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the loss (gain) from investments, the impact of the settlement of the cross currency swap, and government grant income under the provincial well-site rehabilitation programs. Excluding these items, adjusted net earnings from operations for the second quarter of 2022 were $3,800 million compared with $1,480 million for the second quarter of 2021 and $3,376 million for the first quarter of 2022.

The increase in net earnings and adjusted net earnings from operations for the three and six months ended June 30, 2022 from the comparable periods primarily reflected:

- higher crude oil and NGLs netbacks [(1)] in the Exploration and Production segments;
- higher realized SCO sales prices [(1)] in the Oil Sands Mining and Upgrading segment; and
- higher natural gas netbacks [(1)] and natural gas sales volumes in the North America segment;

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment; and
- higher royalties in the Oil Sands Mining and Upgrading segment.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the six months ended June 30, 2022 were $8,749 million compared with $5,476 million for the six months ended June 30, 2021. Cash flows from operating activities for the second quarter of 2022 were $5,896 million compared with $2,940 million for the second quarter of 2021 and $2,853 million for the first quarter of 2022. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted related to the fluctuations in adjusted net earnings from operations, together with the impact of net changes in non-cash working capital.

Adjusted funds flow for the six months ended June 30, 2022 was $10,407 million compared with $5,761 million for the six months ended June 30, 2021. Adjusted funds flow for the second quarter of 2022 was $5,432 million compared with $3,049 million for the second quarter of 2021 and $4,975 million for the first quarter of 2022. 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 excluding the impact of 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.

Production Volumes

Crude oil and NGLs production before royalties for the second quarter of 2022 of 860,338 bbl/d was comparable with 872,718 bbl/d for the second quarter of 2021 and decreased 9% from 945,809 bbl/d for the first quarter of 2022. Natural gas production before royalties for the second quarter of 2022 increased 30% to 2,105 MMcf/d from 1,614 MMcf/d for the second quarter of 2021 and increased 5% from 2,006 MMcf/d for the first quarter of 2022. Total production before royalties for the second quarter of 2022 of 1,211,147 BOE/d increased 6% from 1,141,739 BOE/d for the second quarter of 2021 and decreased 5% from 1,280,180 BOE/d for the first quarter of 2022. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production, before royalties" section of this MD&A.

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

Product Prices

In the Company's Exploration and Production segments, realized crude oil and NGLs prices [1] averaged $115.26 per bbl for the second quarter of 2022, an increase of 88% compared with $61.20 per bbl for the second quarter of 2021, and an increase of 23% from $93.54 per bbl for the first quarter of 2022. The realized natural gas price [1] increased by $4.76 per Mcf to average $7.93 per Mcf for the second quarter of 2022 from $3.17 per Mcf for the second quarter of 2021, and increased 51% from $5.26 per Mcf for the first quarter of 2022. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price increased 81% to average $137.60 per bbl for the second quarter of 2022 from $76.19 per bbl for the second quarter of 2021, and increased 23% from $112.05 per bbl for the first quarter of 2022. The Company's realized pricing reflects 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 [2] averaged $19.58 per bbl for the second quarter of 2022, an increase of 42% from $13.75 per bbl for the second quarter of 2021, and an increase of 24% from $15.80 per bbl for the first quarter of 2022. Natural gas production expense [2] averaged $1.17 per Mcf for the second quarter of 2022, comparable with $1.19 per Mcf for the second quarter of 2021 and a decrease of 11% from $1.31 per Mcf for the first quarter of 2022. In the Oil Sands Mining and Upgrading segment, production costs [2] averaged $33.76 per bbl for the second quarter of 2022, an increase of 33% from $25.46 per bbl for the second quarter of 2021, and an increase of 37% from $24.60 per bbl for the first quarter of 2022. Crude oil and NGLs and natural gas production expense is discussed in detail in the "Production Expense – Exploration and Production" and the "Oil Sands Mining and Upgrading" sections of this MD&A.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

($ millions, except per common share amounts)	**Jun 30 2022**	Mar 31 2022	Dec 31 2021	Sep 30 2021
Product sales [1]	**$ 13,812**	$ 12,132	$ 10,190	$ 8,521
Crude oil and NGLs	**$ 11,727**	$ 10,773	$ 8,979	$ 7,607
Natural gas	**$ 1,605**	$ 1,002	$ 958	$ 694
Net earnings	**$ 3,502**	$ 3,101	$ 2,534	$ 2,202
Net earnings per common share				
– basic	**$ 3.04**	$ 2.66	$ 2.16	$ 1.87
– diluted	**$ 3.00**	$ 2.63	$ 2.14	$ 1.86
($ millions, except per common share amounts)	Jun 30 2021	Mar 31 2021	Dec 31 2020	Sep 30 2020
Product sales [1]	$ 7,124	$ 7,019	$ 5,219	$ 4,676
Crude oil and NGLs	$ 6,382	$ 6,288	$ 4,592	$ 4,202
Natural gas	$ 509	$ 555	$ 496	$ 338
Net earnings	$ 1,551	$ 1,377	$ 749	$ 408
Net earnings per common share				
– basic	$ 1.31	$ 1.16	$ 0.63	$ 0.35
– diluted	$ 1.30	$ 1.16	$ 0.63	$ 0.35

(1) Further details related to product sales for the three months ended June 30, 2022 and 2021 are disclosed in note 17 to the financial statements.

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

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

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

- **Crude oil pricing** – Fluctuating 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 COVID-19 and in connection with governmental responses to COVID-19, and the impact of 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; the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the International segments; and the impact of production curtailments mandated by the Government of Alberta that were suspended effective December 1, 2020.
- **Natural gas pricing** – The impact of 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 North America and the International segments, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, production curtailments mandated by the Government of Alberta that were suspended effective December 1, 2020, and the impact of shut-in production due to lower demand during COVID-19. 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 North America and the International segments, natural decline rates, the temporary shutdown and subsequent reinstatement of the Pine River Gas Plant during 2021, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production volumes, the impact of seasonal conditions, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Transportation, blending, and feedstock expense** – Fluctuations due to the provision recognized relating to the cancellation of the Keystone XL pipeline project in the fourth quarter of 2020.
- **Depletion, depreciation and amortization expense** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, 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, and the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment.
- **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.
- **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. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of any cross currency swap hedges outstanding.
- **Gain on acquisitions, loss (gain) from investments and income from North West Redwater Partnership ("NWRP")** – Fluctuations due to the recognition of gains on acquisitions, loss (gain) from the investments in PrairieSky Royalty Ltd. and Inter Pipeline Ltd. shares, and the distribution from NWRP in the second quarter of 2021.

BUSINESS ENVIRONMENT

Global benchmark crude oil prices increased significantly in the first half of 2022, primarily in response to the impact of the Russian invasion of Ukraine and the OPEC+ decision to adhere to previously agreed upon production cut agreements. Additionally, global economic conditions and outlook continued to improve as the effects of COVID-19 became less impactful on the global economy.

Liquidity

As at June 30, 2022, the Company had undrawn revolving bank credit facilities of $5,520 million. Including cash and cash equivalents and short-term investments, the Company had approximately $6,120 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.

Risks and Uncertainties

COVID-19, including variants of concern, continues to have the potential to further disrupt the Company's operations, projects, and financial condition, through the disruption of the local or global supply chain and transportation services, rising inflation, or the loss of manpower resulting from quarantines that affect the Company's labour pools in their local communities, workforce camps or operating sites or that are instituted by local health authorities as a precautionary measure, any of which may require the Company to temporarily reduce or shutdown its operations depending on their extent and severity. The global economy, including Canada, is experiencing higher and more persistent inflation, in part due to the Russian invasion of Ukraine and ongoing supply constraints due to the impacts of COVID-19. As a result of these conditions, the Company has experienced and may continue to experience higher than normal fluctuations in commodity prices, and may experience inflationary pressures on operating and capital expenditures.

Benchmark Commodity Prices

	Three Months Ended			Six Months Ended	
(Average for the period)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
WTI benchmark price (US$/bbl)	**$ 108.42**	$ 94.38	$ 66.06	**$ 101.44**	$ 61.95
Dated Brent benchmark price (US$/bbl)	**$ 112.67**	$ 99.17	$ 68.63	**$ 105.96**	$ 64.63
WCS Heavy Differential from WTI (US$/bbl)	**$ 12.80**	$ 14.60	$ 11.47	**$ 13.70**	$ 11.95
SCO price (US$/bbl)	**$ 114.35**	$ 93.05	$ 66.49	**$ 103.76**	$ 60.43
Condensate benchmark price (US$/bbl)	**$ 108.35**	$ 96.16	$ 66.39	**$ 102.29**	$ 62.22
Condensate Differential from WTI (US$/bbl)	**$ 0.07**	$ (1.78)	$ (0.33)	**$ (0.85)**	$ (0.27)
NYMEX benchmark price (US$/MMBtu)	**$ 7.17**	$ 4.91	$ 2.83	**$ 6.05**	$ 2.76
AECO benchmark price (C$/GJ)	**$ 5.95**	$ 4.35	$ 2.70	**$ 5.15**	$ 2.74
US/Canadian dollar average exchange rate (US$)	**$ 0.7832**	$ 0.7899	$ 0.8143	**$ 0.7865**	$ 0.8020

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 the volatility of 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 the North America segment are typically based on WTI benchmark pricing. WTI averaged US$101.44 per bbl for the six months ended June 30, 2022, an increase of 64% from US$61.95 per bbl for the six months ended June 30, 2021. WTI averaged US$108.42 per bbl for the second quarter of 2022, an increase of 64% from US$66.06 per bbl for the second quarter of 2021, and an increase of 15% from US$94.38 per bbl for the first quarter of 2022.

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

Crude oil sales contracts for the Company's International segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$105.96 per bbl for the six months ended June 30, 2022, an increase of 64% from US$64.63 per bbl for the six months ended June 30, 2021. Brent averaged US$112.67 per bbl for the second quarter of 2022, an increase of 64% from US$68.63 per bbl for the second quarter of 2021, and an increase of 14% from US$99.17 per bbl for the first quarter of 2022.

The increase in WTI and Brent pricing for the three and six months ended June 30, 2022 from the comparable periods primarily reflected the impact of the Russian invasion of Ukraine and the OPEC+ decision to adhere to the previously agreed upon production cut agreements. Additionally, global demand for crude oil continued to increase due to improved economic conditions as a result of the lessening of earlier COVID-19 restrictions.

The WCS Heavy Differential averaged US$13.70 per bbl for the six months ended June 30, 2022, compared with US$11.95 per bbl for the six months ended June 30, 2021. The WCS Heavy Differential averaged US$12.80 per bbl for the second quarter of 2022, compared with US$11.47 per bbl for the second quarter of 2021, and US$14.60 per bbl for the first quarter of 2022. The narrowing of the WCS Heavy Differential for the second quarter of 2022 from the first quarter of 2022 primarily reflected the impact of increased demand due to seasonal conditions.

The SCO price averaged US$103.76 per bbl for the six months ended June 30, 2022, an increase of 72% from US$60.43 per bbl for the six months ended June 30, 2021. The SCO price averaged US$114.35 per bbl for the second quarter of 2022, an increase of 72% from US$66.49 per bbl for the second quarter of 2021, and an increase of 23% from US$93.05 per bbl for the first quarter of 2022. The increase in SCO pricing for the three and six months ended June 30, 2022 from the comparable periods primarily reflected the increase in WTI benchmark pricing. The SCO differential for the three and six months ended June 30, 2022 also reflected the significant increase in North American diesel demand.

NYMEX natural gas prices averaged US$6.05 per MMBtu for the six months ended June 30, 2022, an increase of US$3.29 per MMBtu from US$2.76 per MMBtu for the six months ended June 30, 2021. NYMEX natural gas prices averaged US$7.17 per MMBtu for the second quarter of 2022, an increase of US$4.34 per MMBtu from US$2.83 per MMBtu for the second quarter of 2021, and an increase of 46% from US$4.91 per MMBtu for the first quarter of 2022. The increase in NYMEX natural gas prices for the three and six months ended June 30, 2022 from the comparable periods primarily reflected increased global demand and related increase in US Liquefied Natural Gas exports.

AECO natural gas prices averaged $5.15 per GJ for the six months ended June 30, 2022, an increase of 88% from $2.74 per GJ for the six months ended June 30, 2021. AECO natural gas prices averaged $5.95 per GJ for the second quarter of 2022, an increase of $3.25 per GJ from $2.70 per GJ for the second quarter of 2021, and an increase of 37% from $4.35 per GJ for the first quarter of 2022. The increase in AECO natural gas prices for the three and six months ended June 30, 2022 from the comparable periods primarily reflected lower storage levels and increased NYMEX benchmark pricing.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**477,478**	484,280	478,314	**480,860**	478,524
North America – Oil Sands Mining and Upgrading (1)	**356,953**	429,826	361,707	**393,188**	414,959
International – Exploration and Production					
North Sea	**10,788**	15,961	16,458	**13,360**	18,199
Offshore Africa	**15,119**	15,742	16,239	**15,429**	14,059
Total International (2)	**25,907**	31,703	32,697	**28,789**	32,258
Total Crude oil and NGLs	**860,338**	945,809	872,718	**902,837**	925,741
Natural gas (MMcf/d) (3)					
North America	**2,089**	1,988	1,594	**2,039**	1,589
International					
North Sea	**2**	3	4	**2**	4
Offshore Africa	**14**	15	16	**15**	13
Total International	**16**	18	20	**17**	17
Total Natural gas	**2,105**	2,006	1,614	**2,056**	1,606
Total Barrels of oil equivalent (BOE/d)	**1,211,147**	1,280,180	1,141,739	**1,245,473**	1,193,434
Product mix					
Light and medium crude oil and NGLs	**11%**	11%	11%	**11%**	11%
Pelican Lake heavy crude oil	**4%**	4%	5%	**4%**	5%
Primary heavy crude oil	**6%**	5%	6%	**5%**	5%
Bitumen (thermal oil)	**21%**	20%	23%	**21%**	22%
Synthetic crude oil (1)	**29%**	34%	32%	**32%**	35%
Natural gas	**29%**	26%	23%	**27%**	22%
Percentage of gross revenue (1) (4) (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**87%**	91%	92%	**89%**	92%
Natural gas	**13%**	9%	8%	**11%**	8%

(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 costs and excluding risk management activities.

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**366,389**	386,621	407,111	**376,449**	414,576
North America – Oil Sands Mining and Upgrading	**265,527**	376,984	331,214	**320,948**	389,441
International – Exploration and Production					
North Sea	**10,770**	15,908	16,380	**13,325**	18,144
Offshore Africa	**13,815**	15,010	15,531	**14,409**	13,440
Total International	**24,585**	30,918	31,911	**27,734**	31,584
Total Crude oil and NGLs	**656,501**	794,523	770,236	**725,131**	835,601
Natural gas (MMcf/d)					
North America	**1,855**	1,829	1,532	**1,842**	1,521
International					
North Sea	**2**	3	4	**2**	4
Offshore Africa	**11**	14	16	**13**	12
Total International	**13**	17	20	**15**	16
Total Natural gas	**1,868**	1,846	1,552	**1,857**	1,537
Total Barrels of oil equivalent (BOE/d)	**967,847**	1,102,221	1,028,908	**1,034,663**	1,091,716

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

Crude oil and NGLs production before royalties for the six months ended June 30, 2022 averaged 902,837 bbl/d, comparable with 925,741 bbl/d for the six months ended June 30, 2021. Crude oil and NGLs production for the second quarter of 2022 averaged 860,338 bbl/d, comparable with 872,718 bbl/d for the second quarter of 2021, and a decrease of 9% from 945,809 bbl/d for the first quarter of 2022. Crude oil and NGLs production for the six months ended June 30, 2022 compared with the six months ended June 30, 2021 reflected the impact of facility restrictions and turnaround activities at the non-operated Scotford Upgrader ("Scotford") in 2022. The decrease in crude oil and NGLs production for the second quarter of 2022 from the first quarter of 2022 primarily reflected the impact of the planned turnarounds at Horizon and Scotford completed in the second quarter of 2022.

Annual crude oil and NGLs production for 2022 is now targeted to average between 946,000 bbl/d and 982,000 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 six months ended June 30, 2022 of 2,056 MMcf/d increased 28% from 1,606 MMcf/d for the six months ended June 30, 2021. Record natural gas production for the second quarter of 2022 of 2,105 MMcf/d increased 30% from 1,614 MMcf/d for the second quarter of 2021, and increased 5% from 2,006 MMcf/d for the first quarter of 2022. The increase in natural gas production for the three and six months ended June 30, 2022 from the comparable periods in 2021 primarily reflected strong drilling results and acquisitions, partially offset by natural field declines. The increase in natural gas production from the first quarter of 2022 primarily reflected strong drilling results, partially offset by natural field declines.

Annual natural gas production for 2022 is now targeted to average between 2,095 MMcf/d and 2,120 MMcf/d. Production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the six months ended June 30, 2022 averaged 480,860 bbl/d, comparable with 478,524 bbl/d for the six months ended June 30, 2021. North America crude oil and NGLs production for the second quarter of 2022 of 477,478 bbl/d was comparable with 478,314 bbl/d for the second quarter of 2021 and 484,280 bbl/d for the first quarter of 2022. Crude oil and NGLs production for the three and six months ended June 30, 2022 from the comparable periods in 2021 primarily reflected strong drilling results and acquisitions completed in the comparable periods, offset by natural field declines.

The Company’s thermal in situ assets continued to demonstrate long life production before royalties, averaging 249,938 bbl/d for the second quarter of 2022, a decrease of 3% from 258,551 bbl/d for the second quarter of 2021, and a decrease of 5% from 261,743 bbl/d for the first quarter of 2022, primarily reflecting planned maintenance at Kirby South.

Pelican Lake heavy crude oil production before royalties for the second quarter of 2022 averaged 51,112 bbl/d, a decrease of 7% from 55,212 bbl/d for the second quarter of 2021, and comparable with 51,991 bbl/d for the first quarter of 2022, demonstrating Pelican Lake's long life low decline production.

Record natural gas production before royalties for the six months ended June 30, 2022 averaged 2,039 MMcf/d, an increase of 28% from 1,589 MMcf/d for the six months ended June 30, 2021. Record natural gas production for the second quarter of 2022 averaged 2,089 MMcf/d, an increase of 31% from 1,594 MMcf/d for the second quarter of 2021, and an increase of 5% from 1,988 MMcf/d for the first quarter of 2022. The increase in natural gas production for the three and six months ended June 30, 2022 from the comparable periods in 2021 primarily reflected strong drilling results and acquisitions, partially offset by natural field declines. The increase in natural gas production for the second quarter of 2022 from the first quarter of 2022 primarily reflected strong drilling results, partially offset by natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the six months ended June 30, 2022 of 393,188 bbl/d decreased 5% from 414,959 bbl/d for the six months ended June 30, 2021. SCO production for the second quarter of 2022 of 356,953 bbl/d was comparable with 361,707 bbl/d for the second quarter of 2021 and decreased 17% from 429,826 bbl/d for the first quarter of 2022. The decrease in SCO production for the six months ended June 30, 2022 from the six months ended June 30, 2021 primarily reflected facility restrictions and turnaround activities at Scotford in 2022. The decrease in SCO production for the second quarter of 2022 from the first quarter of 2022 primarily reflected the impact of the planned turnarounds at Horizon and Scotford, which were completed in the second quarter of 2022.

International – Exploration and Production

International crude oil and NGLs production before royalties for the six months ended June 30, 2022 averaged 28,789 bbl/d, a decrease of 11% from 32,258 bbl/d for the six months ended June 30, 2021. International crude oil and NGLs production for the second quarter of 2022 averaged 25,907 bbl/d, a decrease of 21% from 32,697 bbl/d for the second quarter of 2021 and a decrease of 18% from 31,703 bbl/d for the first quarter of 2022. The decrease in crude oil and NGLs production for the three and six months ended June 30, 2022 from comparable periods primarily reflected unplanned maintenance in the North Sea during the second quarter of 2022, together with 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)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021
International	**460,436**	872,196	728,732

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Crude oil and NGLs ($/bbl) [1]					
Realized price [2]	**$ 115.26**	$ 93.54	$ 61.20	**$ 104.27**	$ 56.87
Transportation [2]	**4.13**	4.18	3.98	**4.16**	3.77
Realized price, net of transportation [2]	**111.13**	89.36	57.22	**100.11**	53.10
Royalties [3]	**25.01**	17.80	8.50	**21.36**	7.07
Production expense [4]	**19.58**	15.80	13.75	**17.67**	14.16
Netback [2]	**$ 66.54**	$ 55.76	$ 34.97	**$ 61.08**	$ 31.87
Natural gas ($/Mcf) [1]					
Realized price [5]	**$ 7.93**	$ 5.26	$ 3.17	**$ 6.63**	$ 3.29
Transportation [6]	**0.52**	0.50	0.48	**0.50**	0.47
Realized price, net of transportation	**7.41**	4.76	2.69	**6.13**	2.82
Royalties [3]	**0.89**	0.42	0.12	**0.66**	0.14
Production expense [4]	**1.17**	1.31	1.19	**1.24**	1.23
Netback [2]	**$ 5.35**	$ 3.03	$ 1.38	**$ 4.23**	$ 1.45
Barrels of oil equivalent ($/BOE) [1]					
Realized price [2]	**$ 88.07**	$ 69.66	$ 46.40	**$ 78.91**	$ 44.08
Transportation [2]	**3.70**	3.72	3.58	**3.72**	3.42
Realized price, net of transportation [2]	**84.37**	65.94	42.82	**75.19**	40.66
Royalties [3]	**17.03**	11.88	5.77	**14.47**	4.93
Production expense [4]	**14.44**	12.70	11.42	**13.57**	11.82
Netback [2]	**$ 52.90**	$ 41.36	$ 25.63	**$ 47.15**	$ 23.91

(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			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Crude oil and NGLs ($/bbl) (1)					
North America (2)	**$ 113.37**	$ 91.44	$ 59.80	**$ 102.25**	$ 55.21
International average (3)	**$ 144.82**	$ 128.35	$ 85.55	**$ 136.71**	$ 80.11
North Sea (3)	**$ 146.06**	$ 125.20	$ 85.09	**$ 137.67**	$ 77.48
Offshore Africa (3)	**$ 143.33**	$ 130.25	$ 85.78	**$ 135.90**	$ 83.62
Crude oil and NGLs average (2)	**$ 115.26**	$ 93.54	$ 61.20	**$ 104.27**	$ 56.87
Natural gas ($/Mcf) (1) (3)					
North America	**$ 7.90**	$ 5.20	$ 3.13	**$ 6.59**	$ 3.27
International average	**$ 11.86**	$ 11.32	$ 5.72	**$ 11.57**	$ 5.48
North Sea	**$ 8.54**	$ 20.68	$ 2.58	**$ 15.80**	$ 2.57
Offshore Africa	**$ 12.31**	$ 9.57	$ 6.50	**$ 10.88**	$ 6.35
Natural gas average	**$ 7.93**	$ 5.26	$ 3.17	**$ 6.63**	$ 3.29
Average ($/BOE) (1) (2)	**$ 88.07**	$ 69.66	$ 46.40	**$ 78.91**	$ 44.08

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

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

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

North America

North America realized crude oil and NGLs prices increased 85% to average $102.25 per bbl for the six months ended June 30, 2022 from $55.21 per bbl for the six months ended June 30, 2021. North America realized crude oil and NGLs prices increased 90% to average $113.37 per bbl for the second quarter of 2022 from $59.80 per bbl for the second quarter of 2021, and increased 24% from $91.44 per bbl for the first quarter of 2022. The increase in realized crude oil and NGLs prices for the three and six months ended June 30, 2022 from the comparable periods was primarily due to higher WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and in the second quarter of 2022 contributed approximately 185,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased by $3.32 per Mcf to average $6.59 per Mcf for the six months ended June 30, 2022 from $3.27 per Mcf for the six months ended June 30, 2021. North America realized natural gas prices increased by $4.77 per Mcf to average $7.90 per Mcf for the second quarter of 2022 from $3.13 per Mcf for the second quarter of 2021, and increased 52% from $5.20 per Mcf for the first quarter of 2022. The increase in realized natural gas prices for the three and six months ended June 30, 2022 from the comparable periods primarily reflected lower storage levels and increased benchmark pricing.

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

	Three Months Ended		
(Quarterly average)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021
Wellhead Price (1)			
Light and medium crude oil and NGLs ($/bbl)	**$ 105.36**	$ 88.63	$ 55.81
Pelican Lake heavy crude oil ($/bbl)	**$ 121.88**	$ 97.73	$ 67.75
Primary heavy crude oil ($/bbl)	**$ 122.14**	$ 97.21	$ 64.24
Bitumen (thermal oil) ($/bbl)	**$ 112.92**	$ 89.93	$ 58.50
Natural gas ($/Mcf)	**$ 7.90**	$ 5.20	$ 3.13

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

International

International realized crude oil and NGLs prices increased 71% to average $136.71 per bbl for the six months ended June 30, 2022 from $80.11 per bbl for the six months ended June 30, 2021. International realized crude oil and NGLs prices increased 69% to average $144.82 per bbl for the second quarter of 2022 from $85.55 per bbl for the second quarter of 2021, and increased 13% from $128.35 per bbl for the first quarter of 2022. Realized crude oil and NGLs prices per barrel 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 and six months ended June 30, 2022 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			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 26.24**	$ 18.64	$ 8.84	**$ 22.39**	$ 7.46
International average	**$ 5.78**	$ 3.93	$ 2.63	**$ 4.87**	$ 1.68
North Sea	**$ 0.24**	$ 0.41	$ 0.39	**$ 0.30**	$ 0.18
Offshore Africa	**$ 12.36**	$ 6.06	$ 3.74	**$ 8.78**	$ 3.68
Crude oil and NGLs average	**$ 25.01**	$ 17.80	$ 8.50	**$ 21.36**	$ 7.07
Natural gas ($/Mcf) (1)					
North America	**$ 0.89**	$ 0.41	$ 0.12	**$ 0.66**	$ 0.14
Offshore Africa	**$ 2.20**	$ 0.98	$ 0.30	**$ 1.57**	$ 0.29
Natural gas average	**$ 0.89**	$ 0.42	$ 0.12	**$ 0.66**	$ 0.14
Average ($/BOE) (1)	**$ 17.03**	$ 11.88	$ 5.77	**$ 14.47**	$ 4.93

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

North America

North America crude oil and NGLs and natural gas royalties for the three and six months ended June 30, 2022 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 22% of product sales for the six months ended June 30, 2022 compared with 14% of product sales for the six months ended June 30, 2021. Crude oil and NGLs royalty rates averaged approximately 23% of product sales for the second quarter of 2022 compared with 15% for the second quarter of 2021 and 20% for the first quarter of 2022. The increase in royalty rates for the three and six months ended June 30, 2022 from the comparable periods was primarily due to higher benchmark prices together with fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 10% of product sales for the six months ended June 30, 2022 compared with 4% of product sales for the six months ended June 30, 2021. Natural gas royalty rates averaged approximately 11% of product sales for the second quarter of 2022 compared with 4% for the second quarter of 2021 and 8% for the first quarter of 2022. The increase in royalty rates for the three and six months ended June 30, 2022 from the comparable periods was primarily due to higher 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 7% for the six months ended June 30, 2022, compared with 4% of product sales for the six months ended June 30, 2021. Royalty rates as a percentage of product sales averaged approximately 9% for the second quarter of 2022 compared with 4% of product sales for the second quarter of 2021 and 5% for the first quarter of 2022. 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			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 17.45**	$ 14.79	$ 12.82	**$ 16.10**	$ 12.81
International average	**$ 53.02**	$ 32.58	$ 29.98	**$ 42.96**	$ 33.19
North Sea	**$ 84.38**	$ 64.24	$ 63.65	**$ 76.28**	$ 47.25
Offshore Africa	**$ 15.73**	$ 13.38	$ 13.20	**$ 14.40**	$ 14.46
Crude oil and NGLs average	**$ 19.58**	$ 15.80	$ 13.75	**$ 17.67**	$ 14.16
Natural gas ($/Mcf) (1)					
North America	**$ 1.15**	$ 1.28	$ 1.15	**$ 1.21**	$ 1.20
International average	**$ 4.12**	$ 4.61	$ 4.09	**$ 4.38**	$ 4.43
North Sea	**$ 6.60**	$ 8.21	$ 6.96	**$ 7.56**	$ 5.97
Offshore Africa	**$ 3.78**	$ 3.93	$ 3.37	**$ 3.86**	$ 3.97
Natural gas average	**$ 1.17**	$ 1.31	$ 1.19	**$ 1.24**	$ 1.23
Average ($/BOE) (1)	**$ 14.44**	$ 12.70	$ 11.42	**$ 13.57**	$ 11.82

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

North America

North America crude oil and NGLs production expense for the six months ended June 30, 2022 averaged $16.10 per bbl, an increase of 26% from $12.81 per bbl for the six months ended June 30, 2021. North America crude oil and NGLs production expense for the second quarter of 2022 of $17.45 per bbl increased 36% from $12.82 per bbl for the second quarter of 2021 and increased 18% from $14.79 per bbl for the first quarter of 2022. The increase in crude oil and NGLs production expense per bbl for the three and six months ended June 30, 2022 from the comparable periods primarily reflected increased energy costs.

North America natural gas production expense for the six months ended June 30, 2022 averaged $1.21 per Mcf, comparable with $1.20 per Mcf for the six months ended June 30, 2021. North America natural gas production expense for the second quarter of 2022 of $1.15 per Mcf was comparable with $1.15 per Mcf for the second quarter of 2021 and decreased 10% from $1.28 per Mcf for the first quarter of 2022. The decrease in natural gas production expense per Mcf for the second quarter of 2022 from the first quarter of 2022 primarily reflected seasonal conditions.

International

International crude oil and NGLs production expense for the six months ended June 30, 2022 averaged $42.96 per bbl, an increase of 29% from $33.19 per bbl for the six months ended June 30, 2021. International crude oil and NGLs production expense for the second quarter of 2022 of $53.02 per bbl increased 77% from $29.98 per bbl for the second quarter of 2021 and increased 63% from $32.58 per bbl for the first quarter of 2022. The increase in crude oil and NGLs production expense per bbl for the three and six months ended June 30, 2022 from the comparable periods primarily reflected the timing of liftings from various fields that have different cost structures, lower production volumes in the North Sea on a relatively fixed cost base, and fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)	Three Months Ended **Jun 30 2022**	 Mar 31 2022	 Jun 30 2021	Six Months Ended **Jun 30 2022**	 Jun 30 2021
North America	**$ 855**	$ 878	$ 881	**$ 1,733**	$ 1,749
North Sea	**50**	29	19	**79**	87
Offshore Africa	**42**	51	44	**93**	75
Depletion, Depreciation and Amortization	**$ 947**	$ 958	$ 944	**$ 1,905**	$ 1,911
$/BOE (1)	**$ 12.14**	$ 12.40	$ 13.57	**$ 12.27**	$ 13.63

(1) Calculated as 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.

Depletion, depreciation and amortization expense for the six months ended June 30, 2022 of $12.27 per BOE decreased 10% from $13.63 per BOE for the six months ended June 30, 2021. Depletion, depreciation and amortization expense for the second quarter of 2022 of $12.14 per BOE decreased 11% from $13.57 per BOE for the second quarter of 2021 and was comparable with $12.40 per BOE for the first quarter of 2022. The decrease in depletion, depreciation and amortization expense per BOE for the three and six months ended June 30, 2022 from the comparable periods in 2021 primarily reflected lower depletion rates due to increases to the Company's North America Exploration and Production reserve estimates at December 31, 2021, including the impact of the acquisitions completed during the prior year.

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 **Jun 30 2022**	 Mar 31 2022	 Jun 30 2021	Six Months Ended **Jun 30 2022**	 Jun 30 2021
North America	**$ 35**	$ 35	$ 25	**$ 70**	$ 50
North Sea	**6**	7	5	**13**	10
Offshore Africa	**1**	2	2	**3**	3
Asset Retirement Obligation Accretion	**$ 42**	$ 44	$ 32	**$ 86**	$ 63
$/BOE (1)	**$ 0.55**	$ 0.56	$ 0.46	**$ 0.55**	$ 0.45

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

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

Asset retirement obligation accretion expense for the six months ended June 30, 2022 of $0.55 per BOE increased 22% from $0.45 per BOE for the six months ended June 30, 2021. Asset retirement obligation accretion expense for the second quarter of 2022 of $0.55 per BOE increased 20% from $0.46 per BOE for the second quarter of 2021 and was comparable with $0.56 per BOE for the first quarter of 2022. The increase in asset retirement obligation accretion expense per BOE for the three and six months ended June 30, 2022 from the comparable periods in 2021 primarily reflected the cost estimate and discount rate revisions made to the asset retirement obligation in the fourth quarter of 2021.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. SCO production in the second quarter of 2022 of 356,953 bbl/d decreased from the comparable periods, primarily reflecting planned turnarounds at Horizon and Scotford, which were completed during the second quarter of 2022.

The Company incurred production costs of $1,077 million for the second quarter of 2022, a 27% increase from $850 million for the second quarter of 2021, and a 10% increase from $977 million for the first quarter of 2022. The increase from the second quarter of 2021 primarily reflected increased energy costs. The increase from the first quarter of 2022 primarily reflected increased energy costs and turnaround costs.

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

($/bbl)	Three Months Ended **Jun 30 2022**	Three Months Ended Mar 31 2022	Three Months Ended Jun 30 2021	Six Months Ended **Jun 30 2022**	Six Months Ended Jun 30 2021
Realized SCO sales price (1)	**$ 137.60**	$ 112.05	$ 76.19	**$ 123.42**	$ 69.71
Bitumen value for royalty purposes (2)	**$ 110.96**	$ 85.75	$ 58.46	**$ 97.58**	$ 51.75
Bitumen royalties (3)	**$ 31.63**	$ 13.51	$ 5.92	**$ 21.58**	$ 4.22
Transportation (1)	**$ 2.05**	$ 1.55	$ 1.26	**$ 1.77**	$ 1.17

(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. For SCO sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

The realized SCO sales price averaged $123.42 per bbl for the six months ended June 30, 2022, an increase of 77% from $69.71 per bbl for the six months ended June 30, 2021. The realized SCO sales price averaged $137.60 per bbl for the second quarter of 2022, an increase of 81% from $76.19 per bbl for the second quarter of 2021 and an increase of 23% from $112.05 per bbl for the first quarter of 2022. The increase in the realized SCO sales price for the three and six months ended June 30, 2022 from the comparable periods primarily reflected the increase in WTI benchmark pricing. The realized SCO sales price for the three and six months ended June 30, 2022 also reflected increased North American diesel demand.

The increase in bitumen royalties per bbl for the three and six months ended June 30, 2022 from the comparable periods primarily reflected the impact of Horizon reaching full payout, together with higher prevailing bitumen pricing and higher sliding scale royalty rates.

Transportation expense averaged $1.77 per bbl for the six months ended June 30, 2022, an increase of 51% from $1.17 per bbl for the six months ended June 30, 2021. For the second quarter of 2022, transportation expense averaged $2.05 per bbl, an increase of 63% from $1.26 per bbl for the second quarter of 2021 and an increase of 32% from $1.55 per bbl for the first quarter of 2022. The increase in transportation expense per bbl for the three and six months ended June 30, 2022 from the comparable periods primarily reflected the impact of lower production volumes during the second quarter of 2022.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

($ millions)	Three Months Ended **Jun 30 2022**	Three Months Ended Mar 31 2022	Three Months Ended Jun 30 2021	Six Months Ended **Jun 30 2022**	Six Months Ended Jun 30 2021
Production costs, excluding natural gas costs	**$ 979**	$ 896	$ 799	**$ 1,875**	$ 1,578
Natural gas costs	**98**	81	51	**179**	110
Production costs	**$ 1,077**	$ 977	$ 850	**$ 2,054**	$ 1,688

($/bbl)	Three Months Ended **Jun 30 2022**	 Mar 31 2022	 Jun 30 2021	Six Months Ended **Jun 30 2022**	 Jun 30 2021
Production costs, excluding natural gas costs (1)	**$ 30.69**	$ 22.57	$ 23.94	**$ 26.19**	$ 20.86
Natural gas costs (2)	**3.07**	2.03	1.52	**2.49**	1.45
Production costs (3)	**$ 33.76**	$ 24.60	$ 25.46	**$ 28.68**	$ 22.31
Sales volumes (bbl/d)	**350,500**	441,324	366,843	**395,661**	418,113

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

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

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

Production costs for the six months ended June 30, 2022 of $28.68 per bbl increased 29% from $22.31 per bbl for the six months ended June 30, 2021. Production costs for the second quarter of 2022 averaged $33.76 per bbl, an increase of 33% from $25.46 per bbl for the second quarter of 2021 and an increase of 37% from $24.60 per bbl for the first quarter of 2022. The increase in production costs per bbl for the three and six months ended June 30, 2022 from the comparable periods in 2021 primarily reflected the impact of increased energy costs, together with lower production volumes. The increase in production costs per bbl for the second quarter of 2022 from the first quarter of 2022 primarily reflected increased energy costs, the impact of lower production volumes due to the turnarounds completed during the quarter, and related turnaround costs.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended **Jun 30 2022**	 Mar 31 2022	 Jun 30 2021	Six Months Ended **Jun 30 2022**	 Jun 30 2021
Depletion, depreciation and amortization	**$ 412**	$ 445	$ 441	**$ 857**	$ 891
$/bbl (1)	**$ 12.92**	$ 11.20	$ 13.20	**$ 11.97**	$ 11.77

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

Depletion, depreciation and amortization expense for the six months ended June 30, 2022 of $11.97 per bbl was comparable with $11.77 per bbl for the six months ended June 30, 2021. Depletion, depreciation and amortization expense for the second quarter of 2022 of $12.92 per bbl was comparable with $13.20 per bbl for the second quarter of 2021, and increased 15% from $11.20 per bbl for the first quarter of 2022. The increase in depletion, depreciation and amortization expense on a per barrel basis for the second quarter of 2022 from the first quarter of 2022 primarily reflected the impact of lower sales volumes and minor asset derecognitions during the second quarter of 2022.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended **Jun 30 2022**	 Mar 31 2022	 Jun 30 2021	Six Months Ended **Jun 30 2022**	 Jun 30 2021
Asset retirement obligation accretion	**$ 16**	$ 15	$ 14	**$ 31**	$ 29
$/bbl (1)	**$ 0.48**	$ 0.39	$ 0.43	**$ 0.43**	$ 0.38

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

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

Asset retirement obligation accretion expense for the six months ended June 30, 2022 of $0.43 per bbl increased 13% from $0.38 per bbl for the six months ended June 30, 2021. Asset retirement obligation accretion expense for the second quarter of 2022 of $0.48 per bbl increased 12% from $0.43 per bbl for the second quarter of 2021, and increased 23% from $0.39 per bbl for the first quarter of 2022. The increase in asset retirement obligation accretion expense on a per barrel basis from comparable periods primarily reflected the impact of lower sales volumes.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended **Jun 30 2022**	 Mar 31 2022	 Jun 30 2021	Six Months Ended **Jun 30 2022**	 Jun 30 2021
Product sales					
Midstream activities	**$ 18**	$ 20	$ 21	**$ 38**	$ 40
NWRP, refined product sales and other	**318**	249	171	**567**	302
Segmented revenue	**336**	269	192	**605**	342
Less:					
NWRP, refining toll	**63**	61	72	**124**	130
Midstream activities	**7**	5	7	**12**	12
Production expense	**70**	66	79	**136**	142
NWRP, transportation and feedstock costs	**244**	179	134	**423**	239
Depreciation	**4**	4	3	**8**	7
Income from NWRP	**—**	—	(400)	**—**	(400)
Segmented earnings	**$ 18**	$ 20	$ 376	**$ 38**	$ 354

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 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 second quarter of 2022, production of ultra-low sulphur diesel and other refined products averaged 75,418 BOE/d (18,855 BOE/d to the Company), (three months ended June 30, 2021 – 73,465 BOE/d; 18,366 BOE/d to the Company), reflecting the 25% toll payer commitment.

On June 30, 2021, the equity partners together with the toll payers, agreed to optimize the structure of NWRP to better align the commercial interests of the equity partners and the toll payers (the "Optimization Transaction"). Under the Optimization Transaction, NWRP repaid the Company's and APMC's subordinated debt advances of $555 million each, and the Company received a $400 million distribution from NWRP during the second quarter of 2021.

Subsequent to June 30, 2022, NWRP extended its $3,000 million syndicated credit facility. The revolving credit facility was increased to $2,175 million, with $118 million maturing in June 2023, and $2,057 million maturing in June 2025. The non-revolving credit facility was extended with $60 million maturing in June 2023, and $940 million maturing in June 2025.

As at June 30, 2022, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $587 million (December 31, 2021 – $562 million). For the three months ended June 30, 2022, the unrecognized share of the equity loss was $15 million (six months ended June 30, 2022 – unrecognized equity loss of $25 million; three months ended June 30, 2021 – recovery of unrecognized equity losses of $7 million and partnership distributions of $400 million; six months ended June 30, 2021 – recovery of unrecognized equity losses of $24 million and partnership distributions of $400 million).

ADMINISTRATION EXPENSE

	Three Months Ended			Six Months Ended	
	Jun 30 2022	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Expense ($ millions)	**$ 97**	$ 116	$ 87	**$ 213**	$ 182
$/BOE (1)	**$ 0.89**	$ 0.99	$ 0.84	**$ 0.94**	$ 0.84
Sales volumes (BOE/d) (2)	**1,207,485**	1,300,300	1,131,000	**1,253,636**	1,192,399

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

(2) Total Company sales volumes.

Administration expense for the six months ended June 30, 2022 of $0.94 per BOE increased 12% from $0.84 per BOE for the six months ended June 30, 2021. Administration expense for the second quarter of 2022 of $0.89 per BOE increased 6% from $0.84 per BOE for the second quarter of 2021 and decreased 10% from $0.99 per BOE for the first quarter of 2022. The increase in administration expense per BOE for the three and six months ended June 30, 2022 from the comparable periods in 2021 was primarily due to higher personnel costs, partially offset by the impact of higher overhead recoveries. The decrease in administration expense per BOE for the second quarter of 2022 from the first quarter of 2022 was primarily due to higher personnel costs in the first quarter of 2022.

SHARE-BASED COMPENSATION

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
(Recovery) expense	**$ (45)**	$ 534	$ 137	**$ 489**	$ 266

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

The Company recognized a $489 million share-based compensation expense for the six months ended June 30, 2022, 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. For the three months ended June 30, 2022, the Company recognized a $45 million share-based compensation recovery, primarily as a result of the decrease in the Company's share price to $69.17 at June 30, 2022 from $77.41 at March 31, 2022.

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except effective interest rate)	Three Months Ended **Jun 30 2022**	 Mar 31 2022	 Jun 30 2021	Six Months Ended **Jun 30 2022**	 Jun 30 2021
Interest and other financing expense	**$ 160**	$ 163	$ 177	**$ 323**	$ 362
Interest income and other (1)	**6**	4	15	**10**	27
Interest on long-term debt and lease liabilities (1)	**$ 166**	$ 167	$ 192	**$ 333**	$ 389
Average current and long-term debt (2)	**$ 14,107**	$ 14,950	$ 20,185	**$ 14,529**	$ 20,745
Average lease liabilities (2)	**1,540**	1,551	1,633	**1,545**	1,650
Average long-term debt and lease liabilities (2)	**$ 15,647**	$ 16,501	$ 21,818	**$ 16,074**	$ 22,395
Average effective interest rate (3) (4)	**4.1%**	4.0%	3.5%	**4.0%**	3.4%
Interest and other financing expense per $/BOE (5)	**$ 1.46**	$ 1.40	$ 1.73	**$ 1.43**	$ 1.68
Sales volumes (BOE/d) (6)	**1,207,485**	1,300,300	1,131,000	**1,253,636**	1,192,399

(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 total of interest on long-term debt and lease liabilities divided by the average long-term debt and lease liabilities balance for the respective period. 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 six months ended June 30, 2022 decreased 15% to $1.43 per BOE from $1.68 per BOE for the six months ended June 30, 2021. Interest and other financing expense per BOE for the second quarter of 2022 decreased 16% to $1.46 per BOE from $1.73 per BOE for the second quarter of 2021 and increased 4% from $1.40 per BOE for the first quarter of 2022. The decrease in interest and other financing expense per BOE for the three and six months ended June 30, 2022 from the comparable periods in 2021 was primarily due to lower average debt levels and higher sales volumes. The increase in interest and other financing expense per BOE from the second quarter of 2022 from the first quarter of 2022 was primarily due to lower sales volumes.

The Company's average effective interest rate for the three and six months ended June 30, 2022 increased from the comparable periods in 2021 primarily due to the repayment of the $1,000 million 3.31% medium-term note during the first quarter of 2022 and the repayment of bank credit facilities with lower interest rates.

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			Six Months Ended	
($ millions)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Foreign currency contracts	**$ (19)**	$ 22	$ 15	**$ 3**	$ 30
Natural gas financial instruments [(1)]	**17**	5	3	**22**	(3)
Crude oil and NGLs financial instruments [(1)]	**9**	5	—	**14**	—
Net realized loss	**7**	32	18	**39**	27
Foreign currency contracts	**(1)**	(13)	(4)	**(14)**	(9)
Natural gas financial instruments [(1)]	**(16)**	32	14	**16**	39
Crude oil and NGLs financial instruments [(1)]	**(4)**	7	—	**3**	—
Net unrealized (gain) loss	**(21)**	26	10	**5**	30
Net (gain) loss	**$ (14)**	$ 58	$ 28	**$ 44**	$ 57

(1) 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.

During the six months ended June 30, 2022, net realized risk management losses were related to the settlement of foreign currency contracts, natural gas financial instruments, and crude oil and NGLs financial instruments. The Company recorded a net unrealized loss of $5 million ($1 million after-tax of $4 million) on its risk management activities for the six months ended June 30, 2022, including an unrealized gain of $21 million ($16 million after-tax of $5 million) for the second quarter of 2022 (three months ended March 31, 2022 – unrealized loss of $26 million, $17 million after-tax of $9 million; three months ended June 30, 2021 – unrealized loss of $10 million, $6 million after-tax of $4 million).

Further details related to outstanding derivative financial instruments as at June 30, 2022 are disclosed in note 15 to the financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Net realized (gain) loss	**$ (93)**	$ 10	$ 11	**$ (83)**	$ 21
Net unrealized loss (gain)	**426**	(156)	(151)	**270**	(323)
Net loss (gain) [(1)]	**$ 333**	$ (146)	$ (140)	**$ 187**	$ (302)

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

The net realized foreign exchange gain for the six months ended June 30, 2022 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the settlement of the US$550 million cross currency swap during the second quarter of 2022. The net unrealized foreign exchange loss for the six months ended June 30, 2022 was primarily related to the impact of a weaker Canadian dollar with respect to outstanding US dollar debt and the impact of the settlement of the US$550 million cross currency swap during the second quarter of 2022. The US/Canadian dollar exchange rate as at June 30, 2022 was US$0.7769 (March 31, 2022 – US$0.8010, June 30, 2021 – US$0.8062).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended **Jun 30 2022**	Mar 31 2022	Jun 30 2021	Six Months Ended **Jun 30 2022**	Jun 30 2021
North America [1]	**$ 855**	$ 834	$ 324	**$ 1,689**	$ 609
North Sea	**15**	7	(5)	**22**	6
Offshore Africa	**18**	12	7	**30**	11
PRT [2] – North Sea	**6**	(7)	(12)	**(1)**	(17)
Other taxes	**5**	5	3	**10**	5
Current income tax	**899**	851	317	**1,750**	614
Deferred income tax	**131**	125	129	**256**	150
Income tax	**$ 1,030**	$ 976	$ 446	**$ 2,006**	$ 764
Earnings before taxes	**$ 4,532**	$ 4,077	$ 1,997	**$ 8,609**	$ 3,692
Effective tax rate on net earnings [3]	**23%**	24%	22%	**23%**	21%
Income tax	**$ 1,030**	$ 976	$ 446	**$ 2,006**	$ 764
Tax effect on non-operating items [4]	**(9)**	8	6	**(1)**	11
Current PRT - North Sea	**(6)**	7	12	**1**	17
Other taxes	**(5)**	(5)	(3)	**(10)**	(5)
Effective tax on adjusted net earnings	**$ 1,010**	$ 986	$ 461	**$ 1,996**	$ 787
Adjusted net earnings from operations [5]	**$ 3,800**	$ 3,376	$ 1,480	**$ 7,176**	$ 2,699
Effective tax on adjusted net earnings	**1,010**	986	461	**1,996**	787
Adjusted net earnings from operations, before taxes	**$ 4,810**	$ 4,362	$ 1,941	**$ 9,172**	$ 3,486
Effective tax rate on adjusted net earnings from operations [6] [7]	**21%**	23%	24%	**22%**	23%

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

(2) Petroleum Revenue Tax.

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

(4) Includes the net tax effect of PSUs, unrealized risk management, and abandonment expenditure recovery in adjusted net earnings from operations.

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

(6) 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.

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

The effective tax rate on net earnings and adjusted net earnings from operations for the three and six months ended June 30, 2022 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 corporate income tax and PRT in the North Sea for the three and six months ended June 30, 2022 and the comparable periods included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's reported results of operations, financial position or liquidity.

NET CAPITAL EXPENDITURES [1] [2]

($ millions)	Three Months Ended Jun 30 2022	Mar 31 2022	Jun 30 2021	Six Months Ended Jun 30 2022	Jun 30 2021
Exploration and Evaluation					
Net expenditures	**$ 1**	$ 22	$ 1	**$ 23**	$ 5
Net property acquisitions (dispositions)	**1**	(3)	(4)	**(2)**	(4)
Total Exploration and Evaluation	**2**	19	(3)	**21**	1
Property, Plant and Equipment					
Net property acquisitions	**30**	482	7	**512**	8
Well drilling, completion and equipping	**384**	344	224	**728**	490
Production and related facilities	**293**	211	186	**504**	378
Other	**16**	13	16	**29**	29
Total Property, Plant and Equipment	**723**	1,050	433	**1,773**	905
Total Exploration and Production	**725**	1,069	430	**1,794**	906
Oil Sands Mining and Upgrading					
Project costs	**74**	45	61	**119**	102
Sustaining capital	**375**	206	346	**581**	532
Turnaround costs	**193**	60	74	**253**	103
Other [3]	**2**	1	326	**3**	327
Total Oil Sands Mining and Upgrading	**644**	312	807	**956**	1,064
Midstream and Refining	**3**	2	1	**5**	3
Head office	**8**	5	3	**13**	9
Abandonments expenditures, net [2]	**70**	67	44	**137**	111
Net capital expenditures	**$ 1,450**	$ 1,455	$ 1,285	**$ 2,905**	$ 2,093
By segment					
North America	**$ 675**	$ 1,045	$ 378	**$ 1,720**	$ 797
North Sea	**27**	11	44	**38**	76
Offshore Africa	**23**	13	8	**36**	33
Oil Sands Mining and Upgrading	**644**	312	807	**956**	1,064
Midstream and Refining	**3**	2	1	**5**	3
Head office	**8**	5	3	**13**	9
Abandonments expenditures, net [2]	**70**	67	44	**137**	111
Net capital expenditures	**$ 1,450**	$ 1,455	$ 1,285	**$ 2,905**	$ 2,093

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

(3) Includes the acquisition of a 5% net carried interest on an existing oil sands lease in the second quarter of 2021.

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 six months ended June 30, 2022 were $2,905 million compared with $2,093 million for the six months ended June 30, 2021. Net capital expenditures for the six months ended June 30, 2022 included base capital expenditures [1] of $2,110 million and strategic growth capital expenditures [1] of $285 million, in accordance with the Company's capital budget. The Company also completed strategic acquisitions [1] of $512 million of property, plant and equipment during the six months ended June 30, 2022. Net capital expenditures were $1,450 million for the second quarter of 2022 compared with $1,285 million for the second quarter of 2021 and $1,455 million for the first quarter of 2022.

(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.

2022 Capital Budget

On January 11, 2022, the Company announced its 2022 base capital budget [(1)] targeted at approximately $3,645 million. The budget also includes incremental strategic growth capital of approximately $700 million that targets to add future production and capacity in the Company's long life low decline thermal in situ and Oil Sands Mining and Upgrading assets. On August 3, 2022, the 2022 base capital budget was increased by approximately $200 million to approximately $3,845 million and incremental strategic growth capital was increased by approximately $375 million to approximately $1,075 million.

The 2022 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			Six Months Ended	
(number of net wells)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Net successful natural gas wells	**20**	23	9	**43**	31
Net successful crude oil wells [(3)]	**83**	56	27	**139**	71
Dry wells	**1**	—	—	**1**	—
Total	**104**	79	36	**183**	102
Success rate	**99%**	100%	100%	**99%**	100%

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

(2) In addition, during the second quarter of 2022, on a net basis, the Company drilled 1 service well in the Company's thermal oil projects and 1 service well in Northwest Alberta. During the six months ended June 30, 2022, on a net basis, the Company drilled 351 stratigraphic and 3 service wells in the Oil Sands Mining and Upgrading segment, 18 stratigraphic and 22 service wells in the Company's thermal oil projects, and 1 service well in Northwest Alberta.

(3) Includes bitumen wells.

North America

During the second quarter of 2022, the Company drilled 20 net natural gas wells, 29 net primary heavy crude oil wells, 45 net bitumen (thermal oil) wells and 10 net light crude oil wells.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Jun 30 2022**	Mar 31 2022	Dec 31 2021	Jun 30 2021
Adjusted working capital [(1)]	**$ (99)**	$ 281	$ (480)	$ 723
Long-term debt, net [(2)]	**$ 12,369**	$ 13,782	$ 13,950	$ 18,163
Shareholders' equity	**$ 39,340**	$ 38,490	$ 36,945	$ 34,207
Debt to book capitalization [(2)]	**23.9%**	26.4%	27.4%	34.7%
After-tax return on average capital employed [(3)]	**22.7%**	18.9%	15.6%	8.6%

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

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

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

As at June 30, 2022, 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 is 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, 2021. 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 the implementation of 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.

(1) 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.

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 second quarter of 2022, the Company repaid and cancelled the $500 million non-revolving portion of the $1,000 million term credit facility, reducing the remaining facility to the $500 million revolving facility maturing February 2023.
    - During the first quarter of 2022, the Company repaid $500 million of the $1,150 million non-revolving term credit facility maturing February 2023. During the second quarter of 2022, the Company repaid the remaining $650 million and the facility was cancelled.
    - During the second quarter of 2022, the Company repaid through market purchases $139 million of medium-term notes with interest rates ranging from 1.45% to 3.55%, originally due between 2023 and 2028.
    - Subsequent to June 30, 2022, the Company repaid through market purchases an additional $101 million of medium-term notes.
    - During the first quarter of 2022, the Company repaid $1,000 million of 3.31% medium-term notes.
    - During the first quarter of 2022, the Company discontinued its £5 million demand credit facility related to its North Sea operations.
    - Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, SOFR, US base rate or Canadian prime rate.
    - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
    - In July 2021, 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 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 2021, 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 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 June 30, 2022, the Company had undrawn revolving bank credit facilities of $5,520 million. Including cash and cash equivalents and short-term investments, the Company had approximately $6,120 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit.

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. The Company realized cash proceeds of $158 million on settlement. As at June 30, 2022, the Company had no cross currency swap contracts outstanding.

As at June 30, 2022, the Company had total US dollar denominated debt with a carrying amount of $10,619 million (US$8,250 million), before transaction costs and original issue discounts. As at June 30, 2022, there were no foreign currency contracts designated as cash flow hedges.

Long-term debt, net was $12,369 million as at June 30, 2022, resulting in a debt to book capitalization ratio of 23.9% (December 31, 2021 – 27.4%); this ratio was below the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities are greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt as at June 30, 2022 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 June 30, 2022, 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. Further details related to the Company's commodity derivative financial instruments outstanding as at June 30, 2022 are discussed in note 15 to the financial statements.

As at June 30, 2022, the maturity dates of long-term debt and other long-term liabilities and related interest payments were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt [1]	$ 1,287	$ 1,592	$ 3,692	$ 6,109
Other long-term liabilities [2]	$ 263	$ 163	$ 431	$ 778
Interest and other financing expense [3]	$ 623	$ 574	$ 1,434	$ 3,812

(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, $196 million; one to less than two years, $162 million; two to less than five years, $431 million; and thereafter, $778 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at June 30, 2022.

Share Capital

As at June 30, 2022, there were 1,134,388,000 common shares outstanding (December 31, 2021 – 1,168,369,000 common shares) and 34,489,000 stock options outstanding. As at August 2, 2022, the Company had 1,121,429,000 common shares outstanding and 34,074,000 stock options outstanding.

On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share, beginning with the dividend paid on April 5, 2022. On November 3, 2021, the Board of Directors approved a 25% increase in the quarterly dividend to $0.5875 per common share. On March 3, 2021, the Board of Directors approved an 11% increase in the quarterly dividend to $0.47 per common share, from $0.425 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On August 3, 2022, the Board of Directors approved a special dividend of $1.50 per common share, payable on August 31, 2022.

On March 8, 2022, 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 101,574,207 common shares, representing 10% of the public float, over a 12-month period commencing March 11, 2022 and ending March 10, 2023.

For the six months ended June 30, 2022, the Company purchased 42,150,000 common shares at a weighted average price of $73.26 per common share for a total cost of $3,088 million. Retained earnings were reduced by $2,708 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2022, the Company purchased 13,750,000 common shares at a weighted average price of $66.00 per common share for a total cost of $907 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at June 30, 2022:

($ millions)	Remaining 2022	2023	2024	2025	2026	Thereafter
Product transportation and processing [(1)]	$ 551	$ 1,075	$ 1,127	$ 1,027	$ 966	$ 11,702
North West Redwater Partnership service toll [(2)]	$ 67	$ 134	$ 133	$ 131	$ 111	$ 4,178
Offshore vessels and equipment	$ 67	$ 40	$ —	$ —	$ —	$ —
Field equipment and power	$ 22	$ 21	$ 21	$ 21	$ 21	$ 226
Other	$ 13	$ 22	$ 23	$ 21	$ 16	$ —

(1) Includes commitments pertaining to a 20-year product transportation agreement on the Trans Mountain Pipeline Expansion.

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $2,007 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, 2021.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting during the six months ended June 30, 2022 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 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 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. 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			Six Months Ended	
($ millions)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Net earnings	**$ 3,502**	$ 3,101	$ 1,551	**$ 6,603**	$ 2,928
Share-based compensation, net of tax (1)	**(47)**	526	132	**479**	258
Unrealized risk management (gain) loss, net of tax (2)	**(16)**	17	6	**1**	21
Unrealized foreign exchange loss (gain), net of tax (3)	**426**	(156)	(151)	**270**	(323)
Realized foreign exchange gain on settlement of cross currency swap, net of tax (4)	**(69)**	—	—	**(69)**	—
Loss (gain) from investments, net of tax (5)	**25**	(83)	(47)	**(58)**	(164)
Other, net of tax (6)	**(21)**	(29)	(11)	**(50)**	(21)
Non-operating items, net of tax	**298**	275	(71)	**573**	(229)
Adjusted net earnings from operations	**$ 3,800**	$ 3,376	$ 1,480	**$ 7,176**	$ 2,699

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings. Pre-tax share-based compensation for the three months ended June 30, 2022 was a recovery of $45 million (three months ended March 31, 2022 – $534 million expense, three months ended June 30, 2021 – $137 million expense; six months ended June 30, 2022 – $489 million expense, six months ended June 30, 2021 – $266 million expense).

(2) Derivative financial instruments are recognized at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than those amounts reflected in the financial statements due to changes in prices of the underlying items hedged, primarily natural gas and foreign exchange. Pre-tax unrealized risk management gain for the three months ended June 30, 2022 was $21 million (three months ended March 31, 2022 – $26 million loss, three months ended June 30, 2021 – $10 million loss; six months ended June 30, 2022 – $5 million loss, six months ended June 30, 2021 – $30 million loss).

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

(4) 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. The Company realized cash proceeds of $158 million on settlement. Pre- and after-tax amounts for this realized foreign exchange gain on settlement of cross currency 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 losses (gains) recognized in net earnings. There is zero net tax impact on these losses (gains) from investments.

(6) Other relates to the impact of government grant income under the provincial well-site rehabilitation programs. Pre-tax other for the three months ended June 30, 2022 was $27 million (three months ended March 31, 2022 – $38 million, three months ended June 30, 2021 – $14 million; six months ended June 30, 2022 – $65 million, six months ended June 30, 2021 – $27 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 and to repay debt. A reconciliation for adjusted funds flow, from cash flows from operating activities is presented below.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Cash flows from operating activities	**$ 5,896**	$ 2,853	$ 2,940	**$ 8,749**	$ 5,476
Net change in non-cash working capital	**(478)**	1,940	137	**1,462**	147
Abandonment expenditures, net (1)	**70**	67	44	**137**	111
Movements in other long-term assets (2)	**(56)**	115	(72)	**59**	27
Adjusted funds flow	**$ 5,432**	$ 4,975	$ 3,049	**$ 10,407**	$ 5,761

(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.

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.

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 annual capital budget. 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			Six Months Ended	
($ millions)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Abandonment expenditures	**$ 97**	$ 105	$ 58	**$ 202**	$ 138
Government grants for abandonment expenditures	**(27)**	(38)	(14)	**(65)**	(27)
Abandonment expenditures, net	**$ 70**	$ 67	$ 44	**$ 137**	$ 111

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, natural gas 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 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			Six Months Ended	
($ millions, except bbl/d and $/bbl)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Crude oil and NGLs (bbl/d)					
North America	**475,744**	494,810	468,265	**485,224**	472,990
International					
North Sea	**16,530**	11,245	8,939	**13,902**	19,196
Offshore Africa	**13,902**	18,550	17,932	**16,214**	14,407
Total International	**30,432**	29,795	26,871	**30,116**	33,603
Total sales volumes	**506,176**	524,605	495,136	**515,340**	506,593
Crude oil and NGLs sales (1)	**$ 6,871**	$ 5,883	$ 3,655	**$ 12,754**	$ 7,028
Less: Blending costs (2)	**1,561**	1,466	897	**3,027**	1,813
Realized crude oil and NGLs sales	**$ 5,310**	$ 4,417	$ 2,758	**$ 9,727**	$ 5,215
Realized price ($/bbl)	**$ 115.26**	$ 93.54	$ 61.20	**$ 104.27**	$ 56.87

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

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

	Three Months Ended			Six Months Ended	
($ millions, except BOE/d and $/BOE)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Barrels of oil equivalent (BOE/d)					
North America	**823,931**	826,161	733,874	**825,040**	737,867
International					
North Sea	**16,845**	11,720	9,624	**14,296**	19,845
Offshore Africa	**16,210**	21,095	20,659	**18,639**	16,574
Total International	**33,055**	32,815	30,283	**32,935**	36,419
Total sales volumes	**856,986**	858,976	764,157	**857,975**	774,286
Barrels of oil equivalent sales (1)	**$ 8,388**	$ 6,832	$ 4,119	**$ 15,220**	$ 7,984
Less: Blending costs (2)	**1,561**	1,466	897	**3,027**	1,813
Less: Sulphur income	**(41)**	(19)	(4)	**(60)**	(6)
Realized barrels of oil equivalent sales	**$ 6,868**	$ 5,385	$ 3,226	**$ 12,253**	$ 6,177
Realized price ($/BOE)	**$ 88.07**	$ 69.66	$ 46.40	**$ 78.91**	$ 44.08

(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 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 are presented below.

	Three Months Ended			Six Months Ended	
($ millions, except $ per unit amounts)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Transportation, blending and feedstock [(1)]	**$ 1,849**	$ 1,754	$ 1,146	**$ 3,603**	$ 2,294
Less: Blending costs	**1,561**	1,466	897	**3,027**	1,813
Transportation	**$ 288**	$ 288	$ 249	**$ 576**	$ 481
Transportation ($/BOE)	**$ 3.70**	$ 3.72	$ 3.58	**$ 3.72**	$ 3.42
Amounts attributed to crude oil and NGLs	**$ 190**	$ 197	$ 179	**$ 387**	$ 345
Transportation ($/bbl)	**$ 4.13**	$ 4.18	$ 3.98	**$ 4.16**	$ 3.77
Amounts attributed to natural gas	**$ 98**	$ 91	$ 70	**$ 189**	$ 136
Transportation ($/Mcf)	**$ 0.52**	$ 0.50	$ 0.48	**$ 0.50**	$ 0.47

(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			Six Months Ended	
($ millions, except $/bbl and royalty rates)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Crude oil and NGLs sales [(1)]	**$ 6,470**	$ 5,539	$ 3,446	**$ 12,009**	$ 6,541
Less: Blending costs [(2)]	**1,561**	1,466	897	**3,027**	1,813
Realized crude oil and NGLs sales	**$ 4,909**	$ 4,073	$ 2,549	**$ 8,982**	$ 4,728
Realized crude oil and NGLs prices ($/bbl)	**$ 113.37**	$ 91.44	$ 59.80	**$ 102.25**	$ 55.21
Crude oil and NGLs royalties [(3)]	**$ 1,136**	$ 830	$ 376	**$ 1,966**	$ 638
Crude oil and NGLs royalty rates	**23%**	20%	15%	**22%**	14%

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

(2) Blending 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 are presented below.

	Three Months Ended			Six Months Ended	
($ millions, except for bbl/d and $/bbl)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
SCO sales volumes (bbl/d)	**350,500**	441,324	366,843	**395,661**	418,113
Crude oil and NGLs sales [1]	**$ 4,962**	$ 4,851	$ 2,794	**$ 9,813**	$ 5,777
Less: Blending and feedstock costs	**573**	401	252	**974**	502
Realized SCO sales	**$ 4,389**	$ 4,450	$ 2,542	**$ 8,839**	$ 5,275
Realized SCO sales price ($/bbl)	**$ 137.60**	$ 112.05	$ 76.19	**$ 123.42**	$ 69.71
Transportation, blending and feedstock [2]	**$ 638**	$ 463	$ 294	**$ 1,101**	$ 591
Less: Blending and feedstock costs	**573**	401	252	**974**	502
Transportation	**$ 65**	$ 62	$ 42	**$ 127**	$ 89
Transportation ($/bbl)	**$ 2.05**	$ 1.55	$ 1.26	**$ 1.77**	$ 1.17

(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.

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, the repayment of NWRP subordinated debt advances, and abandonment expenditures including the impact of government grant income under the provincial well-site rehabilitation programs. 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			Six Months Ended	
($ millions)	**Jun 30 2022**	Mar 31 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Cash flows used in investing activities	**$ 1,345**	$ 1,251	$ 719	**$ 2,596**	$ 1,367
Net change in non-cash working capital	**35**	137	(33)	**172**	60
Repayment of NWRP subordinated debt advances	**—**	—	555	**—**	555
Capital expenditures	**1,380**	1,388	1,241	**2,768**	1,982
Abandonment expenditures, net [1]	**70**	67	44	**137**	111
Net capital expenditures [2]	**$ 1,450**	$ 1,455	$ 1,285	**$ 2,905**	$ 2,093

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

(2) For the six months ended June 30, 2022, includes base capital expenditures of $2,110 million, net property, plant and equipment acquisitions and net exploration and evaluation asset dispositions of $510 million, and strategic growth capital expenditures of $285 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.

Liquidity

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

($ millions)	**Jun 30 2022**	Mar 31 2022	Dec 31 2021	Jun 30 2021
Undrawn bank credit facilities	**$ 5,520**	$ 5,590	$ 6,098	$ 4,959
Cash and cash equivalents	**233**	125	744	168
Investments	**367**	392	309	469
Liquidity	**$ 6,120**	$ 6,107	$ 7,151	$ 5,596

Long-term Debt, net

Long-term debt, net, is a capital management measure that represents long-term debt less cash and cash equivalents, as disclosed in note 13 to the financial statements.

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)	**Jun 30 2022**	Mar 31 2022	Dec 31 2021	Jun 30 2021
Interest adjusted after-tax return:				
Net earnings, 12 months trailing	**$ 11,339**	$ 9,388	$ 7,664	$ 4,085
Interest and other financing expense, net of tax, 12 months trailing (1)	**517**	531	547	546
Interest adjusted after-tax return	**$ 11,856**	$ 9,919	$ 8,211	$ 4,631
12 months average current portion long-term debt (2)	**$ 1,664**	$ 1,762	1,483	$ 1,617
12 months average long-term debt (2)	**13,597**	14,981	16,769	19,321
12 months average common shareholders' equity (2)	**36,902**	35,680	34,458	32,863
12 months average capital employed	**$ 52,163**	$ 52,423	$ 52,710	$ 53,801
After-tax return on average capital employed	**22.7%**	18.9%	15.6%	8.6%

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

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

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Jun 30 2022	Dec 31 2021
ASSETS			
Current assets			
Cash and cash equivalents		**$ 233**	$ 744
Accounts receivable		**5,015**	3,111
Inventory		**1,917**	1,548
Prepaids and other		**343**	195
Investments	6	**367**	309
Current portion of other long-term assets	7	**58**	35
		7,933	5,942
Exploration and evaluation assets	3	**2,238**	2,250
Property, plant and equipment	4	**66,050**	66,400
Lease assets	5	**1,484**	1,508
Other long-term assets	7	**461**	565
		$ 78,166	$ 76,665
LIABILITIES			
Current liabilities			
Accounts payable		**$ 1,150**	$ 803
Accrued liabilities		**4,641**	3,064
Current income taxes payable		**1,159**	1,607
Current portion of long-term debt	8	**1,285**	1,000
Current portion of other long-term liabilities	5,9	**1,082**	948
		9,317	7,422
Long-term debt	8	**11,317**	13,694
Other long-term liabilities	5,9	**7,709**	8,384
Deferred income taxes		**10,483**	10,220
		38,826	39,720
SHAREHOLDERS' EQUITY			
Share capital	11	**10,350**	10,168
Retained earnings		**28,943**	26,778
Accumulated other comprehensive income (loss)	12	**47**	(1)
		39,340	36,945
		$ 78,166	$ 76,665

Commitments and contingencies (note 16).

Approved by the Board of Directors on August 3, 2022.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Jun 30 2022**	Three Months Ended Jun 30 2021	Six Months Ended **Jun 30 2022**	Six Months Ended Jun 30 2021
Product sales	17	**$ 13,812**	$ 7,124	**$ 25,944**	$ 14,143
Less: royalties		**(2,337)**	(599)	**(3,792)**	(1,010)
Revenue		**11,475**	6,525	**22,152**	13,133
Expenses					
Production		**2,287**	1,740	**4,327**	3,521
Transportation, blending and feedstock		**2,682**	1,515	**5,137**	3,023
Depletion, depreciation and amortization	4,5	**1,363**	1,388	**2,770**	2,809
Administration		**97**	87	**213**	182
Share-based compensation	9	**(45)**	137	**489**	266
Asset retirement obligation accretion	9	**58**	46	**117**	92
Interest and other financing expense		**160**	177	**323**	362
Risk management activities	15	**(14)**	28	**44**	57
Foreign exchange loss (gain)		**333**	(140)	**187**	(302)
Income from North West Redwater Partnership	7	**—**	(400)	**—**	(400)
Loss (gain) from investments	6	**22**	(50)	**(64)**	(169)
		6,943	4,528	**13,543**	9,441
Earnings before taxes		**4,532**	1,997	**8,609**	3,692
Current income tax expense	10	**899**	317	**1,750**	614
Deferred income tax expense	10	**131**	129	**256**	150
Net earnings		**$ 3,502**	$ 1,551	**$ 6,603**	$ 2,928
Net earnings per common share					
Basic	14	**$ 3.04**	$ 1.31	**$ 5.70**	$ 2.47
Diluted	14	**$ 3.00**	$ 1.30	**$ 5.63**	$ 2.46

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended **Jun 30 2022**	Three Months Ended Jun 30 2021	Six Months Ended **Jun 30 2022**	Six Months Ended Jun 30 2021
Net earnings	**$ 3,502**	$ 1,551	**$ 6,603**	$ 2,928
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 (2021 – $1 million) – three months ended; $1 million (2021 – $2 million) – six months ended	**1**	7	**4**	18
Reclassification to net earnings, net of taxes of $nil (2021 – $nil) – three months ended; $1 million (2021 – $1 million) – six months ended	**(1)**	(1)	**(4)**	(5)
	—	6	**—**	13
Foreign currency translation adjustment				
Translation of net investment	**85**	(31)	**48**	(67)
Other comprehensive income (loss), net of taxes	**85**	(25)	**48**	(54)
Comprehensive income	**$ 3,587**	$ 1,526	**$ 6,651**	$ 2,874

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Six Months Ended Jun 30 2022	Jun 30 2021
Share capital	11		
Balance – beginning of period		**$ 10,168**	$ 9,606
Issued upon exercise of stock options		**309**	264
Previously recognized liability on stock options exercised for common shares		**253**	39
Purchase of common shares under Normal Course Issuer Bid		**(380)**	(46)
Balance – end of period		**10,350**	9,863
Retained earnings			
Balance – beginning of period		**26,778**	22,766
Net earnings		**6,603**	2,928
Dividends on common shares	11	**(1,730)**	(1,114)
Purchase of common shares under Normal Course Issuer Bid	11	**(2,708)**	(190)
Balance – end of period		**28,943**	24,390
Accumulated other comprehensive income (loss)	12		
Balance – beginning of period		**(1)**	8
Other comprehensive income (loss), net of taxes		**48**	(54)
Balance – end of period		**47**	(46)
Shareholders' equity		**$ 39,340**	$ 34,207

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Jun 30 2022	Three Months Ended Jun 30 2021	Six Months Ended Jun 30 2022	Six Months Ended Jun 30 2021
Operating activities					
Net earnings		**$ 3,502**	$ 1,551	**$ 6,603**	$ 2,928
Non-cash items					
Depletion, depreciation and amortization		**1,363**	1,388	**2,770**	2,809
Share-based compensation		**(45)**	137	**489**	266
Asset retirement obligation accretion		**58**	46	**117**	92
Unrealized risk management (gain) loss		**(21)**	10	**5**	30
Unrealized foreign exchange loss (gain)		**426**	(151)	**270**	(323)
Realized foreign exchange gain on settlement of cross currency swap		**(69)**	—	**(69)**	—
Loss (gain) from investments	6	**25**	(47)	**(58)**	(164)
Deferred income tax expense		**131**	129	**256**	150
Proceeds on settlement of cross currency swap	15	**89**	—	**89**	—
Other		**56**	72	**(59)**	(27)
Abandonment expenditures		**(97)**	(58)	**(202)**	(138)
Net change in non-cash working capital		**478**	(137)	**(1,462)**	(147)
Cash flows from operating activities		**5,896**	2,940	**8,749**	5,476
Financing activities					
Repayment of bank credit facilities and commercial paper, net	8	**(1,504)**	(1,588)	**(1,156)**	(2,988)
Repayment of medium-term notes	8	**(139)**	—	**(1,139)**	—
Proceeds on settlement of cross currency swap	15	**69**	—	**69**	—
Payment of lease liabilities	5,9	**(50)**	(52)	**(99)**	(105)
Issue of common shares on exercise of stock options	11	**57**	191	**309**	264
Dividends on common shares		**(871)**	(557)	**(1,560)**	(1,060)
Purchase of common shares under Normal Course Issuer Bid	11	**(2,005)**	(213)	**(3,088)**	(236)
Cash flows used in financing activities		**(4,443)**	(2,219)	**(6,664)**	(4,125)
Investing activities					
Net (expenditures) proceeds on exploration and evaluation assets	3,17	**(2)**	3	**(21)**	(1)
Net expenditures on property, plant and equipment	4,17	**(1,378)**	(1,244)	**(2,747)**	(1,981)
Repayment of North West Redwater Partnership subordinated debt advances	7	**—**	555	**—**	555
Net change in non-cash working capital		**35**	(33)	**172**	60
Cash flows used in investing activities		**(1,345)**	(719)	**(2,596)**	(1,367)
Increase (decrease) in cash and cash equivalents		**108**	2	**(511)**	(16)
Cash and cash equivalents – beginning of period		**125**	166	**744**	184
Cash and cash equivalents – end of period		**$ 233**	$ 168	**$ 233**	$ 168
Interest paid on long-term debt, net		**$ 119**	$ 142	**$ 303**	$ 354
Income taxes paid (received), net		**$ 411**	$ 38	**$ 2,170**	$ (83)

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, 2021, 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, 2021.

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 2020, the IASB issued amendments to IAS 16 "Property, Plant and Equipment" to require proceeds received from selling items produced while the entity is preparing the asset for its intended use to be recorded in net earnings, rather than as a reduction in the cost of the asset. The amendments were adopted January 1, 2022 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, 2021	$ 2,057	$ —	$ 91	$ 102	$ 2,250
Additions	**30**	**—**	**1**	**—**	**31**
Transfers to property, plant and equipment	**(43)**	**—**	**—**	**—**	**(43)**
At June 30, 2022	**$ 2,044**	**$ —**	**$ 92**	**$ 102**	**$ 2,238**

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, 2021	$ 77,834	$ 7,438	$ 3,980	$ 46,856	$ 466	$ 508	$ 137,082
Additions / Acquisitions	**1,723**	**38**	**35**	**956**	**3**	**13**	**2,768**
Transfers from exploration & evaluation assets	**43**	**—**	**—**	**—**	**—**	**—**	**43**
Change in asset retirement obligation estimates	**(84)**	**(103)**	**(38)**	**(328)**	**—**	**—**	**(553)**
Derecognitions (1)	**(177)**	**(1)**	**—**	**(171)**	**—**	**—**	**(349)**
Foreign exchange adjustments and other	**—**	**127**	**68**	**—**	**—**	**—**	**195**
At June 30, 2022	**$ 79,339**	**$ 7,499**	**$ 4,045**	**$ 47,313**	**$ 469**	**$ 521**	**$ 139,186**
Accumulated depletion and depreciation							
At December 31, 2021	$ 52,732	$ 5,951	$ 2,923	$ 8,499	$ 183	$ 394	$ 70,682
Expense	**1,687**	**76**	**79**	**800**	**8**	**11**	**2,661**
Derecognitions (1)	**(177)**	**(1)**	**—**	**(171)**	**—**	**—**	**(349)**
Foreign exchange adjustments and other	**(10)**	**99**	**49**	**3**	**—**	**1**	**142**
At June 30, 2022	**$ 54,232**	**$ 6,125**	**$ 3,051**	**$ 9,131**	**$ 191**	**$ 406**	**$ 73,136**
Net book value							
At June 30, 2022	**$ 25,107**	**$ 1,374**	**$ 994**	**$ 38,182**	**$ 278**	**$ 115**	**$ 66,050**
At December 31, 2021	$ 25,102	$ 1,487	$ 1,057	$ 38,357	$ 283	$ 114	$ 66,400

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

During the six months ended June 30, 2022, the Company acquired a number of crude oil and natural gas properties in the North America Exploration and Production segment for net cash consideration of $512 million and assumed associated asset retirement obligations of $12 million. No net deferred income tax liabilities were recognized and no pre-tax gains were recognized on these net transactions.

5. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2021	$ 974	$ 354	$ 99	$ 81	$ 1,508
Additions	**44**	**20**	**21**	**—**	**85**
Depreciation	**(54)**	**(30)**	**(14)**	**(11)**	**(109)**
Foreign exchange adjustments and other	**1**	**—**	**(2)**	**1**	**—**
At June 30, 2022	**$ 965**	**$ 344**	**$ 104**	**$ 71**	**$ 1,484**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at June 30, 2022 were as follows:

	Jun 30 2022	Dec 31 2021
Lease liabilities	**$ 1,567**	$ 1,584
Less: current portion	**196**	185
	$ 1,371	$ 1,399

Total cash outflows for leases for the three months ended June 30, 2022, including payments related to short-term leases not reported as lease assets, were $289 million (three months ended June 30, 2021 – $286 million; six months ended June 30, 2022 – $556 million; six months ended June 30, 2021 – $574 million). Interest expense on leases for the three months ended June 30, 2022 was $15 million (three months ended June 30, 2021 – $16 million; six months ended June 30, 2022 – $30 million; six months ended June 30, 2021 – $32 million).

6. INVESTMENTS

As at June 30, 2022, the Company had the following investment:

	Jun 30 2022	Dec 31 2021
Investment in PrairieSky Royalty Ltd.	**$ 367**	$ 309

The loss (gain) from the investments was comprised as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2022	Jun 30 2021 (1)	**Jun 30 2022**	Jun 30 2021 (1)
Loss (gain) from investments	**$ 25**	$ (47)	**$ (58)**	$ (164)
Dividend income	**(3)**	(3)	**(6)**	(5)
	$ 22	$ (50)	**$ (64)**	$ (169)

(1) Includes the gain and dividend income from the Company's investment in Inter Pipeline Ltd.

The Company's 22.6 million share investment 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 June 30, 2022, the market price per common share was $16.21 (December 31, 2021 – $13.63; June 30, 2021 – $15.01).

7. OTHER LONG-TERM ASSETS

		Jun 30 2022		Dec 31 2021
Prepaid cost of service tolls	**$**	**155**	$	157
Long-term inventory		**136**		126
Risk management (note 15)		**1**		140
Long-term contracts and prepayments (1)		**227**		177
		519		600
Less: current portion		**58**		35
	$	**461**	$	565

(1) Includes physical product sales contracts assumed in the acquisition of Painted Pony in the fourth quarter of 2020, 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).

On June 30, 2021, the equity partners together with the toll payers, agreed to optimize the structure of NWRP to better align the commercial interests of the equity partners and the toll payers (the "Optimization Transaction"). Under the Optimization Transaction, NWRP repaid the Company's and APMC's subordinated debt advances of $555 million each, and the Company received a $400 million distribution from NWRP during the second quarter of 2021.

Subsequent to June 30, 2022, NWRP extended its $3,000 million syndicated credit facility. The revolving credit facility was increased to $2,175 million, with $118 million maturing in June 2023, and $2,057 million maturing in June 2025. The non-revolving credit facility was extended with $60 million maturing in June 2023, and $940 million maturing in June 2025.

The carrying value of the Company's interest in NWRP is $nil, and as at June 30, 2022, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $587 million (December 31, 2021 – $562 million). For the three months ended June 30, 2022, the unrecognized share of the equity loss was $15 million (six months ended June 30, 2022 – unrecognized equity loss of $25 million; three months ended June 30, 2021 – recovery of unrecognized equity losses of $7 million and partnership distributions of $400 million; six months ended June 30, 2021 – recovery of unrecognized equity losses of $24 million and partnership distributions of $400 million).

8. LONG-TERM DEBT

		Jun 30 2022		Dec 31 2021
Canadian dollar denominated debt, unsecured				
Medium-term notes	**$**	**2,061**	$	3,200
US dollar denominated debt, unsecured				
Bank credit facilities (June 30, 2022 – US$nil; December 31, 2021 – US$901 million)		**—**		1,140
US dollar debt securities (June 30, 2022 – US$8,250 million; December 31, 2021 – US$8,250 million)		**10,619**		10,441
		10,619		11,581
Long-term debt before transaction costs and original issue discounts, net		**12,680**		14,781
Less: original issue discounts, net [1]		**14**		15
transaction costs [1] [2]		**64**		72
		12,602		14,694
Less: current portion of other long-term debt [1] [2]		**1,285**		1,000
	$	**11,317**	$	13,694

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

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

Bank Credit Facilities and Commercial Paper

As at June 30, 2022, the Company had undrawn revolving bank credit facilities of $5,520 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 term credit facility, maturing February 2023;
- a $2,425 million revolving syndicated credit facility maturing June 2024; and
- a $2,495 million revolving syndicated credit facility, with $70 million maturing June 2023, and $2,425 million maturing June 2025.

During the second quarter of 2022, the Company repaid and cancelled the $500 million non-revolving portion of the $1,000 million term credit facility, reducing the remaining facility to the $500 million revolving facility maturing February 2023.

During the first quarter of 2022, the Company repaid $500 million of the $1,150 million non-revolving term credit facility maturing February 2023. During the second quarter of 2022, the Company repaid the remaining $650 million and the facility was cancelled.

Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, SOFR, US base rate or Canadian prime rate.

During the first quarter of 2022, the Company discontinued its £5 million demand credit facility related to its North Sea operations.

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

The Company's weighted average interest rate on total long-term debt outstanding for the six months ended June 30, 2022 was 4.0% (June 30, 2021 – 3.4%).

As at June 30, 2022, letters of credit and guarantees aggregating to $529 million were outstanding.

Medium-Term Notes

In July 2021, 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 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 second quarter of 2022, the Company repaid through market purchases $139 million of medium-term notes with interest rates ranging from 1.45% to 3.55%, originally due between 2023 and 2028. Subsequent to June 30, 2022, the Company repaid through market purchases an additional $101 million of medium-term notes.

During the first quarter of 2022, the Company repaid $1,000 million of 3.31% medium-term notes.

US Dollar Debt Securities

In July 2021, 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 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

	Jun 30 2022	Dec 31 2021
Asset retirement obligations	**$ 6,205**	$ 6,806
Lease liabilities (note 5)	**1,567**	1,584
Share-based compensation	**655**	489
Transportation and processing contracts	**197**	241
Risk management (note 15)	**43**	85
Other (1)	**124**	127
	8,791	9,332
Less: current portion	**1,082**	948
	$ 7,709	$ 8,384

(1) Includes $25 million (December 31, 2021 – $48 million) in deferred purchase consideration payable in the first quarter of 2023.

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 5.6% (December 31, 2021 – 4.0%) with inflation rates of up to approximately 10% for 2022, returning to up to approximately 2% thereafter (December 31, 2021 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Jun 30 2022	Dec 31 2021
Balance – beginning of period	**$ 6,806**	$ 5,861
Liabilities incurred	**10**	5
Liabilities acquired, net	**12**	76
Liabilities settled	**(202)**	(307)
Asset retirement obligation accretion	**117**	185
Revision of cost estimates	**519**	508
Revision of timing estimates (1)	**626**	1,208
Change in discount rates	**(1,698)**	(723)
Foreign exchange adjustments	**15**	(7)
Balance – end of period	**6,205**	6,806
Less: current portion	**280**	249
	$ 5,925	$ 6,557

(1) Reflects changes to the estimated timing of the settlement of the Company's asset retirement obligations in the Province of Alberta due to provincial regulatory changes.

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

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

	Jun 30 2022	Dec 31 2021
Balance – beginning of period	**$ 489**	$ 160
Share-based compensation expense	**489**	514
Cash payment for stock options surrendered and PSUs vested	**(74)**	(48)
Transferred to common shares	**(253)**	(139)
Other	**4**	2
Balance – end of period	**655**	489
Less: current portion	**461**	329
	$ 194	$ 160

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Six Months Ended	
Expense (recovery)	**Jun 30 2022**	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Current corporate income tax – North America	**$ 855**	$ 324	**$ 1,689**	$ 609
Current corporate income tax – North Sea	**15**	(5)	**22**	6
Current corporate income tax – Offshore Africa	**18**	7	**30**	11
Current PRT [(1)] – North Sea	**6**	(12)	**(1)**	(17)
Other taxes	**5**	3	**10**	5
Current income tax	**899**	317	**1,750**	614
Deferred income tax	**131**	129	**256**	150
Income tax	**$ 1,030**	$ 446	**$ 2,006**	$ 764

(1) Petroleum Revenue Tax

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued common shares	Six Months Ended Jun 30, 2022 Number of shares (thousands)		Amount
Balance – beginning of period	**1,168,369**	**$**	**10,168**
Issued upon exercise of stock options	**8,169**		**309**
Previously recognized liability on stock options exercised for common shares	**—**		**253**
Purchase of common shares under Normal Course Issuer Bid	**(42,150)**		**(380)**
Balance – end of period	**1,134,388**	**$**	**10,350**

Dividend Policy

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

On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share, beginning with the dividend paid on April 5, 2022. On November 3, 2021, the Board of Directors approved a 25% increase in the quarterly dividend to $0.5875 per common share. On March 3, 2021, the Board of Directors approved an 11% increase in the quarterly dividend to $0.47 per common share, from $0.425 per common share.

On August 3, 2022, the Board of Directors approved a special dividend of $1.50 per common share, payable on August 31, 2022.

Normal Course Issuer Bid

On March 8, 2022, 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 101,574,207 common shares, representing 10% of the public float, over a 12-month period commencing March 11, 2022 and ending March 10, 2023.

For the six months ended June 30, 2022, the Company purchased 42,150,000 common shares at a weighted average price of $73.26 per common share for a total cost of $3,088 million. Retained earnings were reduced by $2,708 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2022, the Company purchased 13,750,000 common shares at a weighted average price of $66.00 per common share for a total cost of $907 million.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding as at June 30, 2022:

	Six Months Ended Jun 30, 2022 Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of period	**38,327**	**$**	**35.88**
Granted	**6,390**	**$**	**67.30**
Exercised for common shares	**(8,169)**	**$**	**37.85**
Surrendered for cash settlement	**(324)**	**$**	**38.17**
Forfeited	**(1,735)**	**$**	**39.94**
Outstanding – end of period	**34,489**	**$**	**41.01**
Exercisable – end of period	**4,996**	**$**	**36.67**

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 (LOSS)

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

	Jun 30 2022	Jun 30 2021
Derivative financial instruments designated as cash flow hedges	**$ 77**	$ 82
Foreign currency translation adjustment	**(30)**	(128)
	$ 47	$ (46)

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 to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic 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%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. As at June 30, 2022, the ratio was below the target range at 23.9%.

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.

	Jun 30 2022	Dec 31 2021
Long-term debt	**$ 12,602**	$ 14,694
Less: cash and cash equivalents	**233**	744
Long-term debt, net	**$ 12,369**	$ 13,950
Total shareholders' equity	**$ 39,340**	$ 36,945
Debt to book capitalization	**23.9%**	27.4%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at June 30, 2022, the Company was in compliance with this covenant.

14. NET EARNINGS PER COMMON SHARE

		Three Months Ended		Six Months Ended	
		Jun 30 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Weighted average common shares outstanding – basic (thousands of shares)		**1,151,111**	1,185,301	**1,157,914**	1,185,425
Effect of dilutive stock options (thousands of shares)		**15,464**	5,163	**15,482**	3,038
Weighted average common shares outstanding – diluted (thousands of shares)		**1,166,575**	1,190,464	**1,173,396**	1,188,463
Net earnings		**$ 3,502**	$ 1,551	**$ 6,603**	$ 2,928
Net earnings per common share	– basic	**$ 3.04**	$ 1.31	**$ 5.70**	$ 2.47
	– diluted	**$ 3.00**	$ 1.30	**$ 5.63**	$ 2.46

15. FINANCIAL INSTRUMENTS

The carrying amounts of the Company's financial instruments by category were as follows:

	Jun 30, 2022				
Asset (liability)	**Financial assets at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Cash and cash equivalents	**$ 233**	**$ —**	**$ —**	**$ —**	**$ 233**
Accounts receivable	**5,015**	**—**	**—**	**—**	**5,015**
Investments	**—**	**367**	**—**	**—**	**367**
Other long-term assets	**—**	**1**	**—**	**—**	**1**
Accounts payable	**—**	**—**	**—**	**(1,150)**	**(1,150)**
Accrued liabilities	**—**	**—**	**—**	**(4,641)**	**(4,641)**
Other long-term liabilities (1)	**—**	**(43)**	**—**	**(1,592)**	**(1,635)**
Long-term debt (2)	**—**	**—**	**—**	**(12,602)**	**(12,602)**
	$ 5,248	**$ 325**	**$ —**	**$ (19,985)**	**$ (14,412)**

	Dec 31, 2021				
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Cash and cash equivalents	$ 744	$ —	$ —	$ —	$ 744
Accounts receivable	3,111	—	—	—	3,111
Investments	—	309	—	—	309
Other long-term assets	—	—	140	—	140
Accounts payable	—	—	—	(803)	(803)
Accrued liabilities	—	—	—	(3,064)	(3,064)
Other long-term liabilities (1)	—	(64)	(21)	(1,632)	(1,717)
Long-term debt (2)	—	—	—	(14,694)	(14,694)
	$ 3,855	$ 245	$ 119	$ (20,193)	$ (15,974)

(1) Includes $1,567 million of lease liabilities (December 31, 2021 – $1,584 million) and $25 million of deferred purchase consideration payable in the first quarter of 2023 (December 31, 2021 – $48 million).

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

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The fair values of the Company's investments, recurring other long-term assets (liabilities) and fixed rate long-term debt are outlined below:

	Jun 30, 2022			
	Carrying amount	**Fair value**		
Asset (liability) [1] [2]		**Level 1**	**Level 2**	**Level 3** [4]
Investments [3]	**$ 367**	**$ 367**	**$ —**	**$ —**
Other long-term assets	**$ 1**	**$ —**	**$ 1**	**$ —**
Other long-term liabilities	**$ (68)**	**$ —**	**$ (43)**	**$ (25)**
Fixed rate long-term debt [5] [6]	**$ (12,602)**	**$ (12,595)**	**$ —**	**$ —**

	Dec 31, 2021			
	Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3 [4]
Investments [3]	$ 309	$ 309	$ —	$ —
Other long-term assets	$ 140	$ —	$ 140	$ —
Other long-term liabilities	$ (133)	$ —	$ (85)	$ (48)
Fixed rate long-term debt [5] [6]	$ (13,554)	$ (15,420)	$ —	$ —

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the short-term nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).

(2) There were no transfers between Level 1, 2 and 3 financial instruments.

(3) The fair values of the investments are based on quoted market prices.

(4) The fair value of the deferred purchase consideration included in other long-term liabilities is based on the present value of future cash payments.

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

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

Risk Management

The Company periodically uses derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)	**Jun 30 2022**	Dec 31 2021
Derivatives held for trading		
Natural gas [1]	**$ (37)**	$ (41)
Crude oil and NGLs [1]	**(6)**	(10)
Foreign currency forward contracts	**1**	(13)
Cash flow hedges		
Foreign currency forward contracts	**—**	(21)
Cross currency swaps	**—**	140
	$ (42)	$ 55
Included within:		
Current portion of other long-term assets	**$ 1**	$ 5
Current portion of other long-term liabilities	**(42)**	(72)
Other long-term assets	**—**	135
Other long-term liabilities	**(1)**	(13)
	$ (42)	$ 55

(1) Commodity financial instruments assumed in the acquisitions of Storm Resources Ltd. and Painted Pony Energy Ltd. in the fourth quarter of 2021 and 2020, respectively.

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. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs as applicable, including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States interest rate yield curves, and Canadian and United States forward foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

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

Asset (liability)	**Jun 30 2022**	Dec 31 2021
Balance – beginning of period	**$ 55**	$ (24)
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	**22**	(12)
Foreign exchange	**(119)**	82
Other comprehensive income	**—**	9
Balance – end of period	**(42)**	55
Less: current portion	**(41)**	(67)
	$ (1)	$ 122

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

	Three Months Ended		Six Months Ended	
	Jun 30 2022	Jun 30 2021	**Jun 30 2022**	Jun 30 2021
Net realized risk management loss	**$ 7**	$ 18	**$ 39**	$ 27
Net unrealized risk management (gain) loss	**(21)**	10	**5**	30
	$ (14)	$ 28	**$ 44**	$ 57

Financial Risk Factors

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.

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. As at June 30, 2022, the Company had no significant interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. As at June 30, 2022, the Company had no cross currency swap contracts outstanding.

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. The Company realized cash proceeds of $158 million on settlement.

As at June 30, 2022, the Company had US$526 million of foreign currency forward contracts outstanding, 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 June 30, 2022, 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. As at June 30, 2022, the Company had net risk management assets of $1 million with specific counterparties related to derivative financial instruments (December 31, 2021 – $140 million).

The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

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

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

As at June 30, 2022, 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	$ 1,150	$ —	$ —	$ —
Accrued liabilities	$ 4,641	$ —	$ —	$ —
Long-term debt (1)	$ 1,287	$ 1,592	$ 3,692	$ 6,109
Other long-term liabilities (2)	$ 263	$ 163	$ 431	$ 778
Interest and other financing expense (3)	$ 623	$ 574	$ 1,434	$ 3,812

(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, $196 million; one to less than two years, $162 million; two to less than five years, $431 million; and thereafter, $778 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at June 30, 2022.

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 June 30, 2022:

		Remaining 2022		2023		2024		2025		2026		Thereafter
Product transportation and processing (1)	$	551	$	1,075	$	1,127	$	1,027	$	966	$	11,702
North West Redwater Partnership service toll (2)	$	67	$	134	$	133	$	131	$	111	$	4,178
Offshore vessels and equipment	$	67	$	40	$	—	$	—	$	—	$	—
Field equipment and power	$	22	$	21	$	21	$	21	$	21	$	226
Other	$	13	$	22	$	23	$	21	$	16	$	—

(1) Includes commitments pertaining to a 20-year product transportation agreement on the Trans Mountain Pipeline Expansion.

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $2,007 million of interest payable over the 40-year tolling period, ending in 2058 (note 7).

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

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

17. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2022	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Segmented product sales																
Crude oil and NGLs	**6,470**	3,446	**12,009**	6,541	**220**	69	**347**	269	**181**	140	**398**	218	**6,871**	3,655	**12,754**	7,028
Natural gas	**1,501**	453	**2,431**	939	**1**	1	**6**	2	**15**	10	**29**	15	**1,517**	464	**2,466**	956
Other income and revenue (1)	**69**	22	**139**	53	**2**	—	**3**	—	**2**	1	**4**	3	**73**	23	**146**	56
Total segmented product sales	**8,040**	3,921	**14,579**	7,533	**223**	70	**356**	271	**198**	151	**431**	236	**8,461**	4,142	**15,366**	8,040
Less: royalties	**(1,309)**	(395)	**(2,216)**	(680)	**(1)**	(1)	**(1)**	(1)	**(19)**	(6)	**(30)**	(10)	**(1,329)**	(402)	**(2,247)**	(691)
Segmented revenue	**6,731**	3,526	**12,363**	6,853	**222**	69	**355**	270	**179**	145	**401**	226	**7,132**	3,740	**13,119**	7,349
Segmented expenses																
Production	**973**	714	**1,860**	1,441	**128**	54	**195**	168	**25**	26	**53**	47	**1,126**	794	**2,108**	1,656
Transportation, blending and feedstock	**1,847**	1,144	**3,599**	2,290	**2**	2	**4**	4	**—**	—	**—**	—	**1,849**	1,146	**3,603**	2,294
Depletion, depreciation and amortization	**855**	881	**1,733**	1,749	**50**	19	**79**	87	**42**	44	**93**	75	**947**	944	**1,905**	1,911
Asset retirement obligation accretion	**35**	25	**70**	50	**6**	5	**13**	10	**1**	2	**3**	3	**42**	32	**86**	63
Risk management activities (commodity derivatives)	**6**	17	**55**	36	**—**	—	**—**	—	**—**	—	**—**	—	**6**	17	**55**	36
Income from North West Redwater Partnership	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**3,716**	2,781	**7,317**	5,566	**186**	80	**291**	269	**68**	72	**149**	125	**3,970**	2,933	**7,757**	5,960
Segmented earnings (loss)	**3,015**	745	**5,046**	1,287	**36**	(11)	**64**	1	**111**	73	**252**	101	**3,162**	807	**5,362**	1,389
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange loss (gain)																
Loss (gain) from investments																
Total non–segmented expenses																
Earnings before taxes																
Current income tax																
Deferred income tax																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream and Refining				Inter–segment elimination and other				Total			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2022	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Segmented product sales																
Crude oil and NGLs [2]	**4,962**	2,794	**9,813**	5,777	**18**	21	**38**	40	**(124)**	(88)	**(105)**	(175)	**11,727**	6,382	**22,500**	12,670
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**88**	45	**141**	108	**1,605**	509	**2,607**	1,064
Other income and revenue [1]	**80**	30	**115**	40	**318**	171	**567**	302	**9**	9	**9**	11	**480**	233	**837**	409
Total segmented product sales	**5,042**	2,824	**9,928**	5,817	**336**	192	**605**	342	**(27)**	(34)	**45**	(56)	**13,812**	7,124	**25,944**	14,143
Less: royalties	**(1,008)**	(197)	**(1,545)**	(319)	**—**	—	**—**	—	**—**	—	**—**	—	**(2,337)**	(599)	**(3,792)**	(1,010)
Segmented revenue	**4,034**	2,627	**8,383**	5,498	**336**	192	**605**	342	**(27)**	(34)	**45**	(56)	**11,475**	6,525	**22,152**	13,133
Segmented expenses																
Production	**1,077**	850	**2,054**	1,688	**70**	79	**136**	142	**14**	17	**29**	35	**2,287**	1,740	**4,327**	3,521
Transportation, blending and feedstock [2]	**638**	294	**1,101**	591	**244**	134	**423**	239	**(49)**	(59)	**10**	(101)	**2,682**	1,515	**5,137**	3,023
Depletion, depreciation and amortization	**412**	441	**857**	891	**4**	3	**8**	7	**—**	—	**—**	—	**1,363**	1,388	**2,770**	2,809
Asset retirement obligation accretion	**16**	14	**31**	29	**—**	—	**—**	—	**—**	—	**—**	—	**58**	46	**117**	92
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**6**	17	**55**	36
Income from North West Redwater Partnership	**—**	—	**—**	—	**—**	(400)	**—**	(400)	**—**	—	**—**	—	**—**	(400)	**—**	(400)
Total segmented expenses	**2,143**	1,599	**4,043**	3,199	**318**	(184)	**567**	(12)	**(35)**	(42)	**39**	(66)	**6,396**	4,306	**12,406**	9,081
Segmented earnings (loss)	**1,891**	1,028	**4,340**	2,299	**18**	376	**38**	354	**8**	8	**6**	10	**5,079**	2,219	**9,746**	4,052
Non–segmented expenses																
Administration													**97**	87	**213**	182
Share-based compensation													**(45)**	137	**489**	266
Interest and other financing expense													**160**	177	**323**	362
Risk management activities (other)													**(20)**	11	**(11)**	21
Foreign exchange loss (gain)													**333**	(140)	**187**	(302)
Loss (gain) from investments													**22**	(50)	**(64)**	(169)
Total non-segmented expenses													**547**	222	**1,137**	360
Earnings before taxes													**4,532**	1,997	**8,609**	3,692
Current income tax													**899**	317	**1,750**	614
Deferred income tax													**131**	129	**256**	150
Net earnings													**3,502**	1,551	**6,603**	2,928

(1) Includes the sale of diesel and other refined products and other income, including government grants and recoveries associated with the joint operations partners' share of the costs of lease contracts.
(2) Includes blending and feedstock costs associated with the processing of third party bitumen and other purchased feedstock in the Oil Sands Mining and Upgrading segment.

Capital Expenditures [1]

	Six Months Ended					
	Jun 30, 2022			Jun 30, 2021		
	Net expenditures	**Non-cash and fair value changes** [2]	**Capitalized costs**	Net expenditures (proceeds)	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ 20**	**$ (33)**	**$ (13)**	$ (2)	$ (31)	$ (33)
Offshore Africa	**1**	**—**	**1**	3	—	3
	21	**(33)**	**(12)**	1	(31)	(30)
Property, plant and equipment						
Exploration and Production						
North America	**1,700**	**(195)**	**1,505**	799	(153)	646
North Sea	**38**	**(104)**	**(66)**	76	(6)	70
Offshore Africa	**35**	**(38)**	**(3)**	30	—	30
	1,773	**(337)**	**1,436**	905	(159)	746
Oil Sands Mining and Upgrading [3]	**956**	**(499)**	**457**	1,064	(300)	764
Midstream and Refining	**5**	**(2)**	**3**	3	—	3
Head office	**13**	**—**	**13**	9	—	9
	2,747	**(838)**	**1,909**	1,981	(459)	1,522
	$ 2,768	**$ (871)**	**$ 1,897**	$ 1,982	$ (490)	$ 1,492

(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.

(3) Net expenditures includes the acquisition of a 5% net carried interest on an existing oil sands lease in the second quarter of 2021.

Segmented Assets

	Jun 30 2022	Dec 31 2021
Exploration and Production		
North America	**$ 31,345**	$ 30,645
North Sea	**1,494**	1,561
Offshore Africa	**1,268**	1,332
Other	**34**	40
Oil Sands Mining and Upgrading	**42,838**	42,016
Midstream and Refining	**1,008**	886
Head office	**179**	185
	$ 78,166	$ 76,665

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 2021. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended June 30, 2022:	
Interest coverage (times)	
Net earnings (1)	23.1x
Adjusted funds flow (2)	32.8x

(1) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(2) Adjusted funds flow plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

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CORPORATE INFORMATION

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Barry Duncan
Managing Director and
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Stock Listing

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

Registrar and Transfer Agent

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