THIRD QUARTER REPORT

NINE MONTHS ENDED SEPTEMBER 30, 2022 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2022 THIRD QUARTER RESULTS

Canadian Natural's President, Tim McKay, commented on the Company's third quarter 2022 results "We remain focused on safe, reliable, effective and efficient operations and our 2022 capital program remains unchanged at approximately $4.9 billion, excluding acquisitions. Our culture of continuous improvement and focus on cost control combined with our disciplined and balanced approach to capital allocation continues to drive strong operational and financial results. We achieved record total quarterly production of approximately 1,339,000 BOE/d, including 487,553 bbl/d of Synthetic Crude Oil ("SCO"), reflecting strong operational performance on our long life zero decline Oil Sands Mining and Upgrading assets which comprises approximately 50% of our total company liquids production. Our high value SCO captured a strong price premium to WTI of US$8.87/bbl in the quarter, driving strong SCO pricing of $120.91/bbl and generating significant free cash flow for the Company. Natural gas production also set a new quarterly record, at approximately 2,132 MMcf/d, which also achieved strong realized pricing, averaging $6.57/Mcf, which is above the AECO monthly benchmark price as a result of our diversified sales points.

On October 4th, the Pathways Alliance ("Pathways") reached an important milestone, securing the right to continue exploratory work for CO_2 injection at Pathways' proposed carbon capture and storage hub located near Cold Lake, Alberta, allowing us to advance to the next stage of evaluation. We are progressing with continued stakeholder engagement and more detailed engineering work on the approximately 400 kilometer long trunkline that will carry captured CO_2 from oil sands facilities to the storage hub. We would like to thank the Alberta government for their continued support as we work together on this ambitious major emissions reduction project to achieve net zero greenhouse gas ("GHG") emissions in the oil sands, supporting Canada's environmental goals. Additionally, we appreciate the federal government's recent public statements in support of the Canadian oil and gas sector's role in global energy security along with commitment to be competitive on fiscal frameworks for carbon capture. These are important steps to help the Canadian oil sands energy industry meet its commitment of net zero GHG emissions by 2050, which will result in the industry and governments investing approximately $24 billion between now and 2030 on Pathways' foundational carbon capture and storage project and other emissions reduction projects.

Benefiting from the effective and efficient operations at Canadian Natural, payments to governments, investment in the oil and gas sector and returns to shareholders have been significant in 2022. Total forecasted payments by Canadian Natural to Canadian governments from income taxes, property taxes and royalties is estimated to be approximately $11 billion in 2022, an increase of approximately $6 billion, or 120% from 2021 levels. Additionally, our 2022 capital spend forecast of approximately $4.9 billion, excluding acquisitions, is an increase of approximately $1.4 billion, or 41% from 2021 levels, delivering responsibly produced energy to help meet global energy demand. As well, in 2022, we have returned approximately $4.9 billion to our shareholders through our quarterly dividends and special dividend, an increase of approximately $2.8 billion, or 127% from 2021 levels."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "The combination of our leading financial results and our top tier asset base provides unique competitive advantages which drive substantial cash flow generation and shareholder returns. Canadian Natural generated approximately $5.2 billion in adjusted funds flow in the third quarter, resulting in free cash flow of approximately $1.7 billion, after total dividends payments of approximately $2.5 billion and base capital expenditures of approximately $1.0 billion, excluding net acquisitions and strategic growth capital.

Subsequent to quarter end, the Board of Directors has approved a 13% increase to our quarterly dividend to $0.85 per common share, from $0.75 per common share, demonstrating the confidence that the Board has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline asset base. The Company's leading track record of dividend increases continues, as this increase marks the 23rd consecutive year of dividend increases.

We maintain a strong balance sheet and financial flexibility as we continue to reduce debt levels. Excluding the impact of foreign exchange, net debt would have decreased by approximately $680 million in the third quarter of 2022. Since September 30, 2021, cumulative repayments of long term debt, excluding foreign exchange impacts, total approximately $4.6 billion.

Our free cash flow allocation policy is unique and balanced, providing significant returns to shareholders through dividends and share repurchases while continuing to strengthen the balance sheet. Given our strong financial position and with our net debt below $15 billion, shareholder returns are not impacted by strategic growth capital or acquisitions. We continue to target to allocate 50% of free cash flow, as defined in our policy, to share repurchases and 50% to the balance sheet, which the Company's Board of Directors will revisit when our net debt level is at or below $8 billion."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Sep 30 2022**	 Jun 30 2022	 Sep 30 2021	Nine Months Ended **Sep 30 2022**	 Sep 30 2021
Net earnings	**$ 2,814**	$ 3,502	$ 2,202	**$ 9,417**	$ 5,130
Per common share – basic	**$ 2.52**	$ 3.04	$ 1.87	**$ 8.23**	$ 4.33
– diluted	**$ 2.49**	$ 3.00	$ 1.86	**$ 8.12**	$ 4.32
Adjusted net earnings from operations (1)	**$ 3,493**	$ 3,800	$ 2,095	**$ 10,669**	$ 4,794
Per common share – basic (2)	**$ 3.12**	$ 3.30	$ 1.78	**$ 9.32**	$ 4.05
– diluted (2)	**$ 3.09**	$ 3.26	$ 1.77	**$ 9.20**	$ 4.04
Cash flows from operating activities	**$ 6,098**	$ 5,896	$ 4,290	**$ 14,847**	$ 9,766
Adjusted funds flow (1)	**$ 5,208**	$ 5,432	$ 3,634	**$ 15,615**	$ 9,395
Per common share – basic (2)	**$ 4.66**	$ 4.72	$ 3.08	**$ 13.64**	$ 7.94
– diluted (2)	**$ 4.60**	$ 4.66	$ 3.07	**$ 13.47**	$ 7.91
Cash flows used in investing activities	**$ 1,129**	$ 1,345	$ 721	**$ 3,725**	$ 2,088
Net capital expenditures (1), excluding net acquisition costs and strategic growth capital (3)	**$ 996**	$ 1,266	$ 881	**$ 3,106**	$ 2,646
Net capital expenditures (1)	**$ 1,249**	$ 1,450	$ 1,011	**$ 4,154**	$ 3,104
Daily production, before royalties					
Natural gas (MMcf/d)	**2,132**	2,105	1,708	**2,081**	1,640
Crude oil and NGLs (bbl/d)	**983,678**	860,338	952,839	**930,079**	934,873
Equivalent production (BOE/d) (4)	**1,338,940**	1,211,147	1,237,503	**1,276,970**	1,208,285

(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 September 30, 2022 dated November 2, 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 September 30, 2022 dated November 2, 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 Q3/22, the Company generated strong financial results, including:
  - Net earnings of approximately $2.8 billion and adjusted net earnings from operations of approximately $3.5 billion.
  - Cash flows from operating activities of approximately $6.1 billion.
  - Adjusted funds flow of approximately $5.2 billion.
  - Free cash flow(1) of approximately $1.7 billion(2) after total dividend payments of approximately $2.5 billion and base capital expenditures(3) of approximately $1.0 billion.
- Returns to shareholders were significant in Q3/22 having returned approximately $4.2 billion, comprised of approximately $2.5 billion in dividends and approximately $1.7 billion in share repurchases.
  - In Q3/22, the Company paid dividends totaling $2.25 per common share, consisting of a quarterly dividend of $0.75 per common share and a special dividend of $1.50 per common share.

- Subsequent to quarter end, the Board of Directors has approved a 13% increase to our quarterly dividend to $0.85 per common share, from $0.75 per common share, payable on January 5, 2023 to shareholders of record on December 16, 2022. This demonstrates the confidence that the Board has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline asset base. The Company's leading track record of dividend increases continues, as this increase will mark the 23rd consecutive year of dividend increases.
  - Canadian Natural increased its sustainable and growing quarterly dividend twice in 2022 for a total combined increase of 45% to $3.40 per share annually.
- In Q3/22, the Company repurchased a total of approximately 25.6 million common shares for cancellation at a weighted average price of $67.89 per share for a total of approximately $1.7 billion.

- Year to date, up to and including November 2, 2022, the Company has returned a total of approximately $10.0 billion to shareholders comprised of approximately $4.9 billion in dividends and approximately $5.1 billion in share repurchases.
  - Year to date, the Company has repurchased a total of approximately 71.2 million common shares for cancellation at a weighted average price of $71.49 per share for a total of approximately $5.1 billion.
- The Company maintains a strong balance sheet and financial flexibility, with net debt(1) of approximately $12.4 billion and significant liquidity(1) of approximately $6.5 billion at the end of Q3/22. Excluding the impact of foreign exchange, net debt would have decreased by approximately $680 million in Q3/22.
  - In Q3/22, the Company repaid through market purchases $341 million of medium-term notes with interest rates ranging from 1.45% to 3.55%, originally due between 2023 and 2028, bringing the total year to date market purchases and associated debt retirement to approximately $485 million.
- In Q3/22, the Company continued its focus on safe, effective and efficient operations, delivering record quarterly average production volumes of 1,338,940 BOE/d, increases of 11% and 8% from Q2/22 and Q3/21 levels respectively.
  - Canadian Natural achieved record quarterly natural gas production of 2,132 MMcf/d in Q3/22, an increase over Q2/22 and a 25% increase over Q3/21 levels. The increase from Q2/22 primarily reflects the impact of strong drilling results, partially offset by natural field declines and planned turnaround activities in Q3/22. The increase from Q3/21 primarily reflects strong drilling results and acquisitions, partially offset by natural field declines.
    - As a result of the Company's diversified sales points, approximately 37% of the Company's natural gas is exported to markets outside of AECO, driving strong realized natural gas pricing averaging $6.57/Mcf in Q3/22, which is above the AECO monthly benchmark price.
  - Quarterly liquids production averaged 983,678 bbl/d in Q3/22, increases of 14% and 3% from Q2/22 and Q3/21 levels respectively. The increase from Q2/22 primarily reflects the completion of planned turnaround activities in Q2/22 at the Company's Oil Sands Mining and Upgrading assets, partially offset by planned maintenance activities on the thermal in situ assets in Q3/22.
    - The Company's world class Oil Sands Mining and Upgrading assets continue to deliver safe and reliable production of SCO, averaging 487,553 bbl/d in Q3/22. Production increased by 37% and 4% from Q2/22 and Q3/21 levels respectively, primarily reflecting strong operational performance following the planned turnaround activities completed at Horizon and Scotford in Q2/22.
      - Approximately 50% of Canadian Natural's total liquids production is comprised of high value SCO from its Oil Sands Mining and Upgrading assets, which captured a strong price premium to WTI of US$8.87/bbl in Q3/22, driving strong SCO average realized pricing of $120.91/bbl and generating significant free cash flow for the Company.

(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 September 30, 2022 dated November 2, 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 September 30, 2022 dated November 2, 2022 for more details on net capital expenditures.

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 the Company's long life low decline production comes from its top tier thermal in situ oil sands operations and Pelican Lake heavy crude oil assets. The combination of these long life low decline assets, low reserves replacement costs, and effective and efficient operations results in substantial and sustainable adjusted funds flow throughout the commodity price cycle.

In addition, Canadian Natural maintains a substantial inventory of low capital exposure projects within the Company's conventional asset base. These projects can be executed quickly and, in the right economic conditions, provide excellent returns and maximize value for our shareholders. Supporting these projects is the Company's undeveloped land base which enables large, repeatable drilling programs that can be optimized over time. Additionally, 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	Nine Months Ended September 30			
	2022		2021	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil [(1)]	**242**	**237**	130	127
Natural gas	**85**	**57**	50	40
Dry	**1**	**1**	1	1
Subtotal	**328**	**295**	181	168
Stratigraphic test / service wells	**477**	**409**	405	336
Total	**805**	**704**	586	504
Success rate (excluding stratigraphic test / service wells)		**99%**		99%

(1) Includes bitumen wells.

- The Company drilled a total of 295 net crude oil and natural gas wells in the nine months ended September 30, 2022 compared to 168 in the comparable period in 2021, an increase of 127 net wells over this time period.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Crude oil and NGLs production (bbl/d)	**228,239**	227,540	206,775	**226,125**	212,565
Net wells targeting crude oil	**60**	39	55	**143**	116
Net successful wells drilled	**60**	38	54	**142**	115
Success rate	**100%**	97%	98%	**99%**	99%

- North America E&P liquids production, excluding thermal in situ, averaged 228,239 bbl/d in Q3/22, comparable to Q2/22 and an increase of 10% over Q3/21. The increase over Q3/21 primarily reflects strong drilling results and acquisitions, partially offset by natural declines.
  - Primary heavy crude oil production averaged 68,933 bbl/d in Q3/22, increases of 4% and 8% from Q2/22 and Q3/21 levels respectively, reflecting strong drilling results, partially offset by natural field declines.
    - Operating costs(1) in the Company's primary heavy crude oil operations averaged $21.30/bbl (US$16.32/bbl) in Q3/22, a decrease of 7% from Q2/22 levels, primarily due to lower fuel costs, partially offset by higher trucking costs.
    - Canadian Natural has one of the largest land bases of Clearwater rights at approximately 940,000 net acres, on which the Company drilled 14 net horizontal multilateral Clearwater wells in the Smith area in Q3/22, bringing the total Clearwater wells drilled and on production year to date to 33 net wells. The Company's total Clearwater production in September 2022 averaged approximately 12,300 bbl/d, an increase of approximately 8,400 bbl/d from the beginning of 2022.
  - Pelican Lake production averaged 50,051 bbl/d in Q3/22, decreases of 2% and 7% from Q2/22 and Q3/21 levels respectively, demonstrating 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 $8.89/bbl (US$6.81/bbl) in Q3/22, an 11% increase from Q2/22 levels, primarily as a result of higher power costs.
  - North America light crude oil and NGL production averaged 109,255 bbl/d in Q3/22, comparable to Q2/22 and up 23% from Q3/21 levels as a result of strong drilling results and acquisitions, partially offset by natural field declines.
    - Operating costs in the Company's North America light crude oil and NGL areas averaged $16.68/bbl (US$12.78/bbl) in Q3/22, an increase of 10% from Q2/22 levels, primarily due to higher power costs.
    - At Wembley, the Company brought a 3 well pad on production in July 2022 at a capital efficiency(2) of approximately $6,000/BOE/d. October 2022 monthly production from these wells averaged approximately 2,000 bbl/d of liquids and 7 MMcf/d of natural gas.
    - At Gold Creek, the Company brought a 2 well pad on production in September 2022 at a strong capital efficiency of approximately $4,300/BOE/d, with strong October 2022 monthly average production of approximately 2,100 bbl/d of liquids and 16 MMcf/d of natural gas.

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

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

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Bitumen production (bbl/d)	**243,393**	249,938	248,113	**251,626**	257,993
Net wells targeting bitumen	**38**	45	—	**95**	7
Net successful wells drilled	**38**	45	—	**95**	7
Success rate	**100%**	100%	—%	**100%**	100%

- Canadian Natural's long life low decline thermal in situ assets averaged 243,393 bbl/d in Q3/22, decreases of 3% and 2% from Q2/22 and Q3/21 levels respectively, primarily reflecting planned maintenance activities at Jackfish in Q3/22 and the low decline nature of these assets.
  - Thermal in situ operating costs averaged $15.63/bbl (US$11.97/bbl) in Q3/22, a decrease of 17% from Q2/22 levels primarily reflecting lower natural gas costs, partially offset by higher power costs.
- As a result of continued strong execution, the Company remains on track to add targeted production of approximately 7,000 bbl/d in 2023, as per the capital update released on August 4, 2022. Capital efficiencies target to average approximately $8,000/bbl/d on Steam Assisted Gravity Drainage ("SAGD") pads and approximately $10,000/bbl/d on cyclic steam stimulation ("CSS") pads.
  - At Kirby, the Company is progressing, as budgeted, with a 3 SAGD pad development and is targeting to begin steam injection on the first pad in Q1/23, with ramp up to full production capacity in Q3/23.
  - At Primrose, the Company completed drilling of two CSS pads on time and on costs. These two pads are targeted to come on production in Q3/23.
- 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.
  - The Company's solvent pilot 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 recovery 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			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Natural gas production (MMcf/d)	**2,117**	2,089	1,698	**2,065**	1,626
Net wells targeting natural gas	**14**	20	9	**57**	40
Net successful wells drilled	**14**	20	9	**57**	40
Success rate	**100%**	100%	100%	**100%**	100%

- Canadian Natural achieved record quarterly North America natural gas production in Q3/22, averaging approximately 2,117 MMcf/d, an increase over Q2/22 and a 25% increase over Q3/21 levels. The increase from Q2/22 primarily reflects the impact of strong drilling results, partially offset by natural field declines and planned turnaround activities in Q3/22. The increase from Q3/21 primarily reflects strong drilling results and acquisitions, partially offset by natural field declines.

- North America natural gas operating costs averaged $1.13/Mcf in Q3/22, a 2% decrease from Q2/22 levels, reflecting the Company's continuous focus on cost control.

▪ Based on the midpoint of the Company's previously updated production guidance, Canadian Natural's diversified natural gas sales points includes the equivalent use of approximately 41% of its natural gas production in its operations, with approximately 37% exported to other North American markets and sold internationally and the remaining 22% sold at AECO/Station 2 pricing.

  - The Company's diversified sales points drove strong realized natural gas pricing averaging $6.51/Mcf in Q3/22, which is above the AECO monthly benchmark price.

▪ Canadian Natural has approximately 1.5 million net acres of Montney rights, providing the Company with significant high value growth opportunities. Montney natural gas production represents approximately 41% of the Company's total natural gas production, with October 2022 Montney production averaging approximately 866 MMcf/d of natural gas with 45,300 bbl/d of liquids. The Company continues to utilize its efficient low cost drill-to-fill strategy to maximize value.

  - At Nig, the Company brought a 6 well pad on production in Q3/22 at a top tier capital efficiency of approximately $2,700/BOE/d. October 2022 monthly production from these wells averaged approximately 55 MMcf/d of natural gas and 3,200 bbl/d of liquids, exceeding budgeted rates and maximizing existing facility capacity.
  - At Townsend, the Company brought a 2 well pad on production in July 2022 at a strong capital efficiency of approximately $4,800/BOE/d. Production from these wells continues to be strong, with average October 2022 monthly production of approximately 20 MMcf/d of natural gas.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Crude oil production (bbl/d)	**24,493**	25,907	29,825	**27,340**	31,439
Natural gas production (MMcf/d)	**15**	16	10	**16**	14
Net wells targeting crude oil	**—**	—	1.9	**—**	4.9
Net successful wells drilled	**—**	—	1.9	**—**	4.9
Success rate	**—%**	—%	100%	**—%**	100%

▪ International E&P crude oil production volumes averaged 24,493 bbl/d in Q3/22, decreases of 5% and 18% from Q2/22 and Q3/21 levels respectively, reflecting planned and unplanned maintenance activities in the North Sea and Offshore Africa during Q3/22, together with natural field declines.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Synthetic crude oil production (bbl/d) (1)(2)	**487,553**	356,953	468,126	**424,988**	432,876

(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 of SCO, averaging 487,553 bbl/d in Q3/22. Production increased by 37% and 4% from Q2/22 and Q3/21 levels respectively, primarily reflecting strong operational performance following the planned turnaround activities completed at Horizon and Scotford in Q2/22.

  - Approximately 50% of Canadian Natural's total liquids production is comprised of high value SCO from its Oil Sands Mining and Upgrading assets, which captured a strong price premium to WTI of US$8.87/bbl in Q3/22, driving strong SCO average realized pricing of $120.91/bbl and generating significant free cash flow for the Company.

- Top tier operating costs were realized in Q3/22, averaging $22.35/bbl (US$17.12/bbl) of SCO, a decrease of 34% from Q2/22 levels and an increase of 13% from Q3/21 levels. The decrease from Q2/22 primarily reflects increased volumes due to the completion of planned turnaround activities in Q2/22 as well as lower natural gas and diesel costs in Q3/22. The increase from Q3/21 primarily reflects higher energy costs.

- At Horizon, the reliability enhancement project is progressing as planned and targets to extend the major maintenance cycle from once per year to once every second year, increasing the SCO production capacity by approximately 5,000 bbl/d in 2023, increasing to approximately 14,000 bbl/d in 2025.
- The Company is progressing on detailed design work of the 750t/hr commercial unit for the In-Pit Extraction Plant ("IPEP") that will provide dry stackable tailings directly in the mine-pit, targeting to reduce GHG emissions and tailings ponds in the future.
- Subsequent to Q3/22, the Company's Oil Sands Mining and Upgrading assets experienced unplanned outages at both Horizon and Scotford upgraders during the month of October 2022, resulting in a Q4/22 targeted production range of 450,000 bbl/d to 460,000 bbl/d of SCO.
  - At Horizon, piping and mechanical repairs in the Primary Upgrading area have been completed and the Company will be enhancing its piping integrity and maintenance programs to support safe and reliable operations.
  - At Scotford, piping repairs in the hydrotreater area were completed by the operator. The Company is working closely with the operator to understand the learnings and the opportunity to enhance the integrity program accordingly.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 91.64**	$ 108.42	$ 70.55	**$ 98.14**	$ 64.85
WCS heavy differential as a percentage of WTI (%) (2)	**22%**	12%	19%	**16%**	19%
SCO price (US$/bbl)	**$ 100.51**	$ 114.35	$ 68.98	**$ 102.66**	$ 63.31
Condensate benchmark pricing (US$/bbl)	**$ 87.15**	$ 108.35	$ 69.22	**$ 97.19**	$ 64.58
Exploration & Production liquids realized pricing (C$/bbl) (3)(4)	**$ 84.91**	$ 115.26	$ 68.06	**$ 97.99**	$ 60.53
SCO realized pricing (C$/bbl) (5)	**$ 120.91**	$ 137.60	$ 81.54	**$ 122.45**	$ 74.00
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 5.51**	$ 5.95	$ 3.36	**$ 5.27**	$ 2.95
Average realized pricing before risk management (C$/Mcf) (4)	**$ 6.57**	$ 7.93	$ 4.13	**$ 6.61**	$ 3.59

(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 September 30, 2022 dated November 2, 2022.

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

- Canadian Natural has many strengths when marketing its products, including a balanced and diverse product mix of natural gas, NGLs, heavy crude oil, light crude oil, thermal in situ bitumen and SCO.
- Crude oil prices in the nine months ended September 30, 2022 were up 51% from the comparable period in 2021, reflecting the impact of the Russian invasion of Ukraine, the OPEC+ decision to adhere to the previously agreed upon production cut agreements, and an increase in global demand for crude oil due to improved economic conditions. The 15% decrease in WTI pricing in Q3/22 compared to Q2/22 reflects a recent decrease in demand due to the impact of rising interest rates and concerns of a global recession.

- SCO benchmark pricing remained strong in Q3/22, averaging US$100.51/bbl, representing a US$8.87/bbl price premium to WTI, reflecting continued strong North American demand for refined products. As a result, realized pricing on the Company's high value SCO averaged $120.91/bbl on record quarterly average sales volumes of 489,146 bbl/d in Q3/22.
- The WCS heavy oil differential as a percentage of WTI was 22% in Q3/22, an increase when compared to 12% in Q2/22 as a result of the weakening of US Gulf Coast heavy oil pricing and an increase in supply from the US Strategic Petroleum Reserve.
- Natural gas prices have strengthened in 2022 compared to 2021, with AECO averaging $5.51/GJ in Q3/22, an increase of 64% from Q3/21, reflecting the increase in the NYMEX North American benchmark price, lower storage levels and increased US Liquefied Natural Gas ("LNG") exports.
- Based on the midpoint of the Company's previously updated production guidance, Canadian Natural's diversified natural gas sales points includes the equivalent use of approximately 41% of its natural gas production in its operations, with approximately 37% exported to other North American markets and sold internationally and the remaining 22% sold at AECO/Station 2 pricing.
  - The Company's diversified sales points drove strong realized natural gas pricing averaging $6.57/Mcf in Q3/22, which is above the AECO monthly benchmark price.
- The North West Redwater ("NWR") Refinery primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 32,252 BOE/d (8,063 BOE/d to the Company) in Q3/22 as a result of its first major turnaround and inspection that commenced in August 2022 and was completed in October 2022.
- Canadian Natural has been a supporter of incremental pipeline projects to ensure Canadian crude oil and natural gas can access global markets to deliver the most responsible and leading ESG production that the world needs.
  - As per Trans Mountain Corporation's press release dated August 29, 2022, timing of the completion of the Trans Mountain Pipeline Expansion remains unchanged, with completion anticipated in Q4/23. Canadian Natural has committed 94,000 bbl/d on the 590,000 bbl/d Trans Mountain Pipeline Expansion.

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 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 $1.7 billion after dividend payments of approximately $2.5 billion and base capital expenditures of approximately $1.0 billion (excluding net acquisitions and strategic growth capital, as per the Company's free cash flow allocation policy).
- Returns to shareholders were significant in Q3/22 having returned approximately $4.2 billion, comprised of approximately $2.5 billion in dividends and approximately $1.7 billion in share repurchases.
  - In Q3/22, the Company paid dividends totaling $2.25 per common share, consisting of a quarterly dividend of $0.75 per common share and a special dividend of $1.50 per common share.
    - Subsequent to quarter end, the Board of Directors approved a 13% increase to the Company's quarterly dividend to $0.85 per common share, from $0.75 per common share, payable on January 5, 2023 to shareholders of record on December 16, 2022. This demonstrates the confidence that the Board has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline asset base. The Company's leading track record of dividend increases continues, as this increase will mark the 23rd consecutive year of dividend increases.
      - Canadian Natural increased its sustainable and growing quarterly dividend twice in 2022 for a total combined increase of 45% to $3.40 per share annually.
  - 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 Q3/22, the Company repurchased a total of approximately 25.6 million common shares for cancellation at a weighted average price of $67.89 per share for a total of approximately $1.7 billion.

- Year to date, up to and including November 2, 2022, the Company has returned approximately $10.0 billion to shareholders through approximately $3.2 billion in quarterly dividends, approximately $1.7 billion in a special dividend paid in August and $5.1 billion from the repurchase and cancellation of approximately 71.2 million common shares.
- The Company maintains a strong balance sheet and financial flexibility, with net debt of approximately $12.4 billion and significant liquidity of approximately $6.5 billion at the end of Q3/22. Excluding the impact of foreign exchange, net debt would have decreased by approximately $680 million in Q3/22.
  - In Q3/22, the Company repaid through market purchases $341 million of medium-term notes with interest rates ranging from 1.45% to 3.55%, originally due between 2023 and 2028, bringing the total year to date market purchases to approximately $485 million.
  - Undrawn revolving bank credit facilities totaling approximately $5.5 billion were available at September 30, 2022. Including cash and cash equivalents and short-term investments, the Company had significant liquidity of approximately $6.5 billion. At September 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.
    - Subsequent to quarter end, the Company extended its $500 million revolving facility for one year, maturing in February 2024. There were no outstanding balances on the facility at quarter end.
- 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.

Pathways Alliance

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 deliver significant emission reductions.

On October 4, 2022, the Alberta government announced it selected 19 carbon capture utilization and storage ("CCUS") proposals, including the Pathways Alliance proposed carbon capture and storage hub near Cold Lake, to advance to the next stage of evaluation. This marks a major milestone of securing the right to continue exploratory work on the Pathways Alliance's CCUS project, an essential part of the Alliance’s plan to reduce emissions by 22 million tonnes per year by 2030 and the first phase towards achieving our 2050 net zero goal.

Stakeholder engagement and engineering work to develop the project is already underway, including an approximately 400 kilometer long trunkline that will carry captured CO_2 from specific capture facilities in the oil sands region to the storage hub. Canadian Natural is appreciative of federal and provincial government support and looks forward to continuing to work together and engaging with Indigenous and local communities in northern Alberta to make this ambitious major emissions-reduction vision a reality. Additionally, we appreciate the federal government's recent public statements in support of the Canadian oil and gas sector's role in global energy security along with commitment to be competitive on fiscal frameworks for carbon capture.

Government Support for Carbon Capture, Utilization and Storage

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 Government of Canada's proposed investment tax credit for CCUS projects for industries across Canada is a positive approach whereby industry and government can co-invest in infrastructure at an achievable pace of development. At the same time, additional government support is required so that the oil and natural gas sector can proceed with a practical and achievable trajectory for GHG emissions reduction. Canadian Natural will continue to provide input to governments 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 September 30, 2022, dated November 2, 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			Nine Months Ended	
($ millions)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Adjusted funds flow [1]	**$ 5,208**	$ 5,432	$ 3,634	**$ 15,615**	$ 9,395
Less: Base capital expenditures [2]	**996**	1,266	881	**3,106**	2,646
Dividends on common shares	**2,532**	871	558	**4,092**	1,667
Free cash flow	**$ 1,680**	$ 3,295	$ 2,195	**$ 8,417**	$ 5,082

(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 September 30, 2022 dated November 2, 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 September 30, 2022 dated November 2, 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 Pathways Alliance ("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; 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 nine months ended September 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 nine months ended September 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 nine months ended September 30, 2022 in relation to the comparable periods in 2021 and the second 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 November 2, 2022.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Sep 30 2022	Three Months Ended Jun 30 2022	Three Months Ended Sep 30 2021	Nine Months Ended Sep 30 2022	Nine Months Ended Sep 30 2021
Product sales [1]	**$ 12,574**	$ 13,812	$ 8,521	**$ 38,518**	$ 22,664
Crude oil and NGLs	**$ 11,001**	$ 11,727	$ 7,607	**$ 33,501**	$ 20,277
Natural gas	**$ 1,342**	$ 1,605	$ 694	**$ 3,949**	$ 1,758
Net earnings	**$ 2,814**	$ 3,502	$ 2,202	**$ 9,417**	$ 5,130
Per common share – basic	**$ 2.52**	$ 3.04	$ 1.87	**$ 8.23**	$ 4.33
– diluted	**$ 2.49**	$ 3.00	$ 1.86	**$ 8.12**	$ 4.32
Adjusted net earnings from operations [2]	**$ 3,493**	$ 3,800	$ 2,095	**$ 10,669**	$ 4,794
Per common share – basic [3]	**$ 3.12**	$ 3.30	$ 1.78	**$ 9.32**	$ 4.05
– diluted [3]	**$ 3.09**	$ 3.26	$ 1.77	**$ 9.20**	$ 4.04
Cash flows from operating activities	**$ 6,098**	$ 5,896	$ 4,290	**$ 14,847**	$ 9,766
Adjusted funds flow [2]	**$ 5,208**	$ 5,432	$ 3,634	**$ 15,615**	$ 9,395
Per common share – basic [3]	**$ 4.66**	$ 4.72	$ 3.08	**$ 13.64**	$ 7.94
– diluted [3]	**$ 4.60**	$ 4.66	$ 3.07	**$ 13.47**	$ 7.91
Cash flows used in investing activities	**$ 1,129**	$ 1,345	$ 721	**$ 3,725**	$ 2,088
Net capital expenditures [2]	**$ 1,249**	$ 1,450	$ 1,011	**$ 4,154**	$ 3,104

(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 nine months ended September 30, 2022 were $9,417 million compared with $5,130 million for the nine months ended September 30, 2021. Net earnings for the nine months ended September 30, 2022 included non-operating items, net of tax, of $1,252 million compared with $336 million for the nine months ended September 30, 2021 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of realized foreign exchange on the settlement of the cross currency swap and repayment of US dollar debt securities, the gain on acquisitions, the (gain) loss from investments, and government grant income under the provincial well-site rehabilitation programs. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2022 were $10,669 million compared with $4,794 million for the nine months ended September 30, 2021.

Net earnings for the third quarter of 2022 were $2,814 million compared with $2,202 million for the third quarter of 2021 and $3,502 million for the second quarter of 2022. Net earnings for the third quarter of 2022 included non-operating items, net of tax, of $679 million compared with $107 million for the third quarter of 2021 and $298 million for the second quarter of 2022 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of realized foreign exchange on the settlement of the cross currency swap and repayment of US dollar debt securities, the gain on acquisitions, the (gain) loss from investments, and government grant income under the provincial well-site rehabilitation programs. Excluding these items, adjusted net earnings from operations for the third quarter of 2022 were $3,493 million compared with $2,095 million for the third quarter of 2021 and $3,800 million for the second quarter of 2022.

The increase in net earnings and adjusted net earnings from operations for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected:

- higher crude oil and NGLs netbacks [(1)] and crude oil and NGLs sales volumes in the North America segment;
- 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:

- higher royalties in the Oil Sands Mining and Upgrading segment.

The decrease in net earnings and adjusted net earnings from operations for the third quarter of 2022 from the second quarter of 2022 primarily reflected:

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

partially offset by:

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

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the nine months ended September 30, 2022 were $14,847 million compared with $9,766 million for the nine months ended September 30, 2021. Cash flows from operating activities for the third quarter of 2022 were $6,098 million compared with $4,290 million for the third quarter of 2021 and $5,896 million for the second 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 nine months ended September 30, 2022 was $15,615 million compared with $9,395 million for the nine months ended September 30, 2021. Adjusted funds flow for the third quarter of 2022 was $5,208 million compared with $3,634 million for the third quarter of 2021 and $5,432 million for the second 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 third quarter of 2022 of 983,678 bbl/d increased 3% from 952,839 bbl/d for the third quarter of 2021 and increased 14% from 860,338 bbl/d for the second quarter of 2022. Natural gas production before royalties for the third quarter of 2022 increased 25% to 2,132 MMcf/d from 1,708 MMcf/d for the third quarter of 2021 and was comparable with 2,105 MMcf/d for the second quarter of 2022. Total production before royalties for the third quarter of 2022 of 1,338,940 BOE/d increased 8% from 1,237,503 BOE/d for the third quarter of 2021 and increased 11% from 1,211,147 BOE/d for the second 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 $84.91 per bbl for the third quarter of 2022, an increase of 25% compared with $68.06 per bbl for the third quarter of 2021, and a decrease of 26% from $115.26 per bbl for the second quarter of 2022. The realized natural gas price increased 59% to average $6.57 per Mcf for the third quarter of 2022, from $4.13 per Mcf for the third quarter of 2021, and decreased 17% from $7.93 per Mcf for the second quarter of 2022. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price increased 48% to average $120.91 per bbl for the third quarter of 2022 from $81.54 per bbl for the third quarter of 2021, and decreased 12% from $137.60 per bbl for the second quarter of 2022. The Company's realized pricing reflected prevailing benchmark pricing. Crude oil and NGLs and natural gas prices are discussed in detail in the "Business Environment", "Realized Product Prices – Exploration and Production", and the "Oil Sands Mining and Upgrading" sections of this MD&A.

Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense (2) averaged $16.86 per bbl for the third quarter of 2022, an increase of 14% from $14.78 per bbl for the third quarter of 2021, and a decrease of 14% from $19.58 per bbl for the second quarter of 2022. Natural gas production expense (2) averaged $1.16 per Mcf for the third quarter of 2022, comparable with $1.17 per Mcf for the third quarter of 2021 and the second quarter of 2022. In the Oil Sands Mining and Upgrading segment, production costs (2) averaged $22.35 per bbl for the third quarter of 2022, an increase of 13% from $19.86 per bbl for the third quarter of 2021, and a decrease of 34% from $33.76 per bbl for the second 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)		**Sep 30 2022**		Jun 30 2022		Mar 31 2022		Dec 31 2021
Product sales (1)	**$**	**12,574**	$	13,812	$	12,132	$	10,190
Crude oil and NGLs	**$**	**11,001**	$	11,727	$	10,773	$	8,979
Natural gas	**$**	**1,342**	$	1,605	$	1,002	$	958
Net earnings	**$**	**2,814**	$	3,502	$	3,101	$	2,534
Net earnings per common share								
– basic	**$**	**2.52**	$	3.04	$	2.66	$	2.16
– diluted	**$**	**2.49**	$	3.00	$	2.63	$	2.14
($ millions, except per common share amounts)		Sep 30 2021		Jun 30 2021		Mar 31 2021		Dec 31 2020
Product sales (1)	$	8,521	$	7,124	$	7,019	$	5,219
Crude oil and NGLs	$	7,607	$	6,382	$	6,288	$	4,592
Natural gas	$	694	$	509	$	555	$	496
Net earnings	$	2,202	$	1,551	$	1,377	$	749
Net earnings per common share								
– basic	$	1.87	$	1.31	$	1.16	$	0.63
– diluted	$	1.86	$	1.30	$	1.16	$	0.63

(1) Further details related to product sales for the three months ended September 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, the impact of inflationary cost pressures, 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, (gain) loss from investments and income from North West Redwater Partnership ("NWRP")** – Fluctuations due to the recognition of gains on acquisitions, (gain) loss 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, together with the improvement of global economic conditions and outlook due to the lessening of COVID-19 restrictions. In the third quarter of 2022, global benchmark crude oil prices decreased from levels in the first half of 2022 due to the impact of rising interest rates and concerns of a global recession.

Liquidity

As at September 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 $6,488 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, or the loss of manpower, 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			Nine Months Ended	
(Average for the period)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
WTI benchmark price (US$/bbl)	**$ 91.64**	$ 108.42	$ 70.55	**$ 98.14**	$ 64.85
Dated Brent benchmark price (US$/bbl)	**$ 99.34**	$ 112.67	$ 72.98	**$ 103.73**	$ 67.44
WCS Heavy Differential from WTI (US$/bbl)	**$ 19.87**	$ 12.80	$ 13.58	**$ 15.78**	$ 12.50
SCO price (US$/bbl)	**$ 100.51**	$ 114.35	$ 68.98	**$ 102.66**	$ 63.31
Condensate benchmark price (US$/bbl)	**$ 87.15**	$ 108.35	$ 69.22	**$ 97.19**	$ 64.58
Condensate Differential from WTI (US$/bbl)	**$ 4.49**	$ 0.07	$ 1.33	**$ 0.95**	$ 0.27
NYMEX benchmark price (US$/MMBtu)	**$ 8.18**	$ 7.17	$ 4.01	**$ 6.77**	$ 3.18
AECO benchmark price (C$/GJ)	**$ 5.51**	$ 5.95	$ 3.36	**$ 5.27**	$ 2.95
US/Canadian dollar average exchange rate (US$)	**$ 0.7660**	$ 0.7832	$ 0.7936	**$ 0.7796**	$ 0.7992

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$98.14 per bbl for the nine months ended September 30, 2022, an increase of 51% from US$64.85 per bbl for the nine months ended September 30, 2021. WTI averaged US$91.64 per bbl for the third quarter of 2022, an increase of 30% from US$70.55 per bbl for the third quarter of 2021, and a decrease of 15% from US$108.42 per bbl for the second 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$103.73 per bbl for the nine months ended September 30, 2022, an increase of 54% from US$67.44 per bbl for the nine months ended September 30, 2021. Brent averaged US$99.34 per bbl for the third quarter of 2022, an increase of 36% from US$72.98 per bbl for the third quarter of 2021, and a decrease of 12% from US$112.67 per bbl for the second quarter of 2022.

The increase in WTI and Brent pricing for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected the impact of the Russian invasion of Ukraine, the OPEC+ decision to adhere to the previously agreed upon production cut agreements, and an increase in global demand for crude oil due to improved economic conditions as a result of the lessening of earlier COVID-19 restrictions. The decrease in WTI and Brent pricing for the third quarter of 2022 from the second quarter of 2022 primarily reflected a decrease in demand due to the impact of rising interest rates and concerns of a global recession.

The WCS Heavy Differential averaged US$15.78 per bbl for the nine months ended September 30, 2022, compared with US$12.50 per bbl for the nine months ended September 30, 2021. The WCS Heavy Differential averaged US$19.87 per bbl for the third quarter of 2022, compared with US$13.58 per bbl for the third quarter of 2021, and US$12.80 per bbl for the second quarter of 2022. The widening of the WCS Heavy Differential for the third quarter of 2022 from the second quarter of 2022 primarily reflected the weakening of US Gulf Coast heavy oil pricing and an increase in supply from the US Strategic Petroleum Reserve.

The SCO price averaged US$102.66 per bbl for the nine months ended September 30, 2022, an increase of 62% from US$63.31 per bbl for the nine months ended September 30, 2021. The SCO price averaged US$100.51 per bbl for the third quarter of 2022, an increase of 46% from US$68.98 per bbl for the third quarter of 2021, and a decrease of 12% from US$114.35 per bbl for the second quarter of 2022. The increase in SCO pricing for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected the increase in WTI benchmark pricing. The strengthening SCO differential for the three and nine months ended September 30, 2022 reflected strong North American diesel demand. The decrease in SCO pricing for the third quarter of 2022 from the second quarter of 2022 primarily reflected the decrease in WTI benchmark pricing.

NYMEX natural gas prices averaged US$6.77 per MMBtu for the nine months ended September 30, 2022, an increase of US$3.59 per MMBtu from US$3.18 per MMBtu for the nine months ended September 30, 2021. NYMEX natural gas prices averaged US$8.18 per MMBtu for the third quarter of 2022, an increase of US$4.17 per MMBtu from US$4.01 per MMBtu for the third quarter of 2021, and an increase of 14% from US$7.17 per MMBtu for the second quarter of 2022. The increase in NYMEX natural gas prices for the three and nine months ended September 30, 2022 from the comparable periods primarily reflected decreased Russian supply to Europe.

AECO natural gas prices averaged $5.27 per GJ for the nine months ended September 30, 2022, an increase of 79% from $2.95 per GJ for the nine months ended September 30, 2021. AECO natural gas prices averaged $5.51 per GJ for the third quarter of 2022, an increase of 64% from $3.36 per GJ for the third quarter of 2021, and a decrease of 7% from $5.95 per GJ for the second quarter of 2022. The increase in AECO natural gas prices for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected lower storage levels and increased NYMEX benchmark pricing. The decrease in AECO natural gas prices for the third quarter of 2022 from the second quarter of 2022 primarily reflected increased production levels and egress restrictions in the Western Canadian Sedimentary Basin.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**471,632**	477,478	454,888	**477,751**	470,558
North America – Oil Sands Mining and Upgrading (1)	**487,553**	356,953	468,126	**424,988**	432,876
International – Exploration and Production					
North Sea	**10,855**	10,788	16,294	**12,514**	17,557
Offshore Africa	**13,638**	15,119	13,531	**14,826**	13,882
Total International (2)	**24,493**	25,907	29,825	**27,340**	31,439
Total Crude oil and NGLs	**983,678**	860,338	952,839	**930,079**	934,873
Natural gas (MMcf/d) (3)					
North America	**2,117**	2,089	1,698	**2,065**	1,626
International					
North Sea	**1**	2	2	**2**	3
Offshore Africa	**14**	14	8	**14**	11
Total International	**15**	16	10	**16**	14
Total Natural gas	**2,132**	2,105	1,708	**2,081**	1,640
Total Barrels of oil equivalent (BOE/d)	**1,338,940**	1,211,147	1,237,503	**1,276,970**	1,208,285
Product mix					
Light and medium crude oil and NGLs	**10%**	11%	10%	**11%**	10%
Pelican Lake heavy crude oil	**4%**	4%	4%	**4%**	5%
Primary heavy crude oil	**5%**	6%	5%	**5%**	5%
Bitumen (thermal oil)	**18%**	21%	20%	**20%**	21%
Synthetic crude oil (1)	**36%**	29%	38%	**33%**	36%
Natural gas	**27%**	29%	23%	**27%**	23%
Percentage of gross revenue (1) (4) (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**88%**	87%	91%	**89%**	92%
Natural gas	**12%**	13%	9%	**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			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**361,987**	366,389	386,416	**371,575**	405,086
North America – Oil Sands Mining and Upgrading	**391,165**	265,527	421,483	**344,611**	400,239
International – Exploration and Production					
North Sea	**10,776**	10,770	16,256	**12,466**	17,508
Offshore Africa	**11,965**	13,815	12,901	**13,586**	13,258
Total International	**22,741**	24,585	29,157	**26,052**	30,766
Total Crude oil and NGLs	**775,893**	656,501	837,056	**742,238**	836,091
Natural gas (MMcf/d)					
North America	**1,920**	1,855	1,609	**1,868**	1,550
International					
North Sea	**1**	2	2	**2**	3
Offshore Africa	**12**	11	7	**13**	11
Total International	**13**	13	9	**15**	14
Total Natural gas	**1,933**	1,868	1,618	**1,883**	1,564
Total Barrels of oil equivalent (BOE/d)	**1,098,001**	967,847	1,106,743	**1,056,008**	1,096,779

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

Crude oil and NGLs production before royalties for the nine months ended September 30, 2022 averaged 930,079 bbl/d, comparable with 934,873 bbl/d for the nine months ended September 30, 2021. Crude oil and NGLs production for the third quarter of 2022 averaged 983,678 bbl/d, an increase of 3% from 952,839 bbl/d for the third quarter of 2021, and an increase of 14% from 860,338 bbl/d for the second quarter of 2022. The increase in crude oil and NGLs production for the third quarter of 2022 from the comparable periods primarily reflected the impact of strong operational performance in the Oil Sands Mining and Upgrading and North America Exploration and Production segments. The increase in crude oil and NGLs production for the third quarter of 2022 from the second quarter of 2022 also reflected the impact of the completion of planned turnarounds at Horizon and Scotford in the second quarter of 2022, partially offset by the impact of planned maintenance activities in thermal in the third quarter of 2022.

Annual crude oil and NGLs production for 2022 is 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 nine months ended September 30, 2022 of 2,081 MMcf/d increased 27% from 1,640 MMcf/d for the nine months ended September 30, 2021. Record natural gas production for the third quarter of 2022 of 2,132 MMcf/d increased 25% from 1,708 MMcf/d for the third quarter of 2021, and was comparable with 2,105 MMcf/d for the second quarter of 2022. The increase in natural gas production for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected strong drilling results and acquisitions, partially offset by natural field declines. Natural gas production in the third quarter of 2022 compared with the second quarter of 2022 primarily reflected strong drilling results, partially offset by natural field declines and turnaround activities in the third quarter.

Annual natural gas production for 2022 is 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 nine months ended September 30, 2022 averaged 477,751 bbl/d, comparable with 470,558 bbl/d for the nine months ended September 30, 2021. North America crude oil and NGLs production for the third quarter of 2022 of 471,632 bbl/d increased 4% from 454,888 bbl/d for the third quarter of 2021 and was comparable with 477,478 bbl/d for the second quarter of 2022. The increase in crude oil and NGLs production for the third quarter of 2022 from the third quarter of 2021 primarily reflected strong drilling results and acquisitions completed in comparable periods, partially offset by natural field declines.

The Company's thermal in situ assets continued to demonstrate long life production before royalties, averaging 243,393 bbl/d for the third quarter of 2022, which was comparable with 248,113 bbl/d for the third quarter of 2021, and a decrease of 3% from 249,938 bbl/d for the second quarter of 2022, reflecting planned maintenance activities completed during the third quarter of 2022.

Pelican Lake heavy crude oil production before royalties for the third quarter of 2022 averaged 50,051 bbl/d, a decrease of 7% from 53,923 bbl/d for the third quarter of 2021, and comparable with 51,112 bbl/d for the second quarter of 2022, demonstrating Pelican Lake's long life low decline production.

Record natural gas production before royalties for the nine months ended September 30, 2022 averaged 2,065 MMcf/d, an increase of 27% from 1,626 MMcf/d for the nine months ended September 30, 2021. Record natural gas production for the third quarter of 2022 averaged 2,117 MMcf/d, an increase of 25% from 1,698 MMcf/d for the third quarter of 2021, and comparable with 2,089 MMcf/d for the second quarter of 2022. The increase in natural gas production for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected strong drilling results and acquisitions, partially offset by natural field declines. Natural gas production in the third quarter of 2022 compared with the second quarter of 2022 primarily reflected strong drilling results, partially offset by natural field declines and turnaround activities in the third quarter.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the nine months ended September 30, 2022 of 424,988 bbl/d was comparable with 432,876 bbl/d for the nine months ended September 30, 2021. SCO production for the third quarter of 2022 of 487,553 bbl/d increased 4% from 468,126 bbl/d for the third quarter of 2021 and increased 37% from 356,953 bbl/d for the second quarter of 2022. SCO production for the nine months ended September 30, 2022 from the nine months ended September 30, 2021 primarily reflected strong operational performance at Horizon, offset by the impact of facility restrictions and turnaround activities at Scotford in the first half of 2022. The increase in SCO production for the third quarter of 2022 from the comparable periods primarily reflected the impact of strong operational performance. The increase in SCO production for the third quarter of 2022 from the second quarter of 2022 also reflected the impact of the completion of planned turnarounds at Horizon and Scotford in the second quarter of 2022.

International – Exploration and Production

International crude oil and NGLs production before royalties for the nine months ended September 30, 2022 averaged 27,340 bbl/d, a decrease of 13% from 31,439 bbl/d for the nine months ended September 30, 2021. International crude oil and NGLs production for the third quarter of 2022 averaged 24,493 bbl/d, a decrease of 18% from 29,825 bbl/d for the third quarter of 2021 and a decrease of 5% from 25,907 bbl/d for the second quarter of 2022. The decrease in crude oil and NGLs production for the three and nine months ended September 30, 2022 from comparable periods primarily reflected planned and unplanned maintenance activities in the North Sea and Offshore Africa during the third 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)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021
International	**1,126,786**	460,436	295,014

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Crude oil and NGLs ($/bbl) (1)					
Realized price (2)	**$ 84.91**	$ 115.26	$ 68.06	**$ 97.99**	$ 60.53
Transportation (2)	**4.10**	4.13	4.00	**4.14**	3.84
Realized price, net of transportation (2)	**80.81**	111.13	64.06	**93.85**	56.69
Royalties (3)	**19.48**	25.01	9.46	**20.75**	7.86
Production expense (4)	**16.86**	19.58	14.78	**17.41**	14.36
Netback (2)	**$ 44.47**	$ 66.54	$ 39.82	**$ 55.69**	$ 34.47
Natural gas ($/Mcf) (1)					
Realized price (5)	**$ 6.57**	$ 7.93	$ 4.13	**$ 6.61**	$ 3.59
Transportation (6)	**0.51**	0.52	0.44	**0.50**	0.46
Realized price, net of transportation	**6.06**	7.41	3.69	**6.11**	3.13
Royalties (3)	**0.61**	0.89	0.22	**0.65**	0.17
Production expense (4)	**1.16**	1.17	1.17	**1.21**	1.21
Netback (2)	**$ 4.29**	$ 5.35	$ 2.30	**$ 4.25**	$ 1.75
Barrels of oil equivalent ($/BOE) (1)					
Realized price (2)	**$ 66.04**	$ 88.07	$ 52.09	**$ 74.62**	$ 46.77
Transportation (2)	**3.64**	3.70	3.50	**3.68**	3.45
Realized price, net of transportation (2)	**62.40**	84.37	48.59	**70.94**	43.32
Royalties (3)	**12.88**	17.03	6.45	**13.94**	5.44
Production expense (4)	**12.68**	14.44	11.91	**13.28**	11.85
Netback (2)	**$ 36.84**	$ 52.90	$ 30.23	**$ 43.72**	$ 26.03

(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						Nine Months Ended			
		Sep 30 2022		Jun 30 2022		Sep 30 2021		**Sep 30 2022**		Sep 30 2021
Crude oil and NGLs ($/bbl) (1)										
North America (2)	**$**	**83.62**	$	113.37	$	66.03	**$**	**96.11**	$	58.74
International average (3)	**$**	**120.09**	$	144.82	$	93.72	**$**	**132.96**	$	84.86
North Sea (3)	**$**	**123.18**	$	146.06	$	96.11	**$**	**135.73**	$	83.03
Offshore Africa (3)	**$**	**119.08**	$	143.33	$	91.73	**$**	**131.02**	$	86.92
Crude oil and NGLs average (2)	**$**	**84.91**	$	115.26	$	68.06	**$**	**97.99**	$	60.53
Natural gas ($/Mcf) (1) (3)										
North America	**$**	**6.51**	$	7.90	$	4.12	**$**	**6.56**	$	3.57
International average	**$**	**14.83**	$	11.86	$	6.09	**$**	**12.60**	$	5.62
North Sea	**$**	**20.88**	$	8.54	$	3.75	**$**	**16.91**	$	2.86
Offshore Africa	**$**	**14.27**	$	12.31	$	6.83	**$**	**11.99**	$	6.46
Natural gas average	**$**	**6.57**	$	7.93	$	4.13	**$**	**6.61**	$	3.59
Average ($/BOE) (1) (2)	**$**	**66.04**	$	88.07	$	52.09	**$**	**74.62**	$	46.77

(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 64% to average $96.11 per bbl for the nine months ended September 30, 2022 from $58.74 per bbl for the nine months ended September 30, 2021. North America realized crude oil and NGLs prices increased 27% to average $83.62 per bbl for the third quarter of 2022 from $66.03 per bbl for the third quarter of 2021, and decreased 26% from $113.37 per bbl for the second quarter of 2022. The increase for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected higher WTI benchmark pricing. The decrease for the third quarter of 2022 from the second quarter of 2022 primarily reflected lower WTI benchmark pricing and the widening of the WCS differential. The Company continues to focus on its crude oil blending marketing strategy and in the third quarter of 2022 contributed approximately 171,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 84% to average $6.56 per Mcf for the nine months ended September 30, 2022 from $3.57 per Mcf for the nine months ended September 30, 2021. North America realized natural gas prices increased 58% to average $6.51 per Mcf for the third quarter of 2022 from $4.12 per Mcf for the third quarter of 2021, and decreased 18% from $7.90 per Mcf for the second quarter of 2022. The increase for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected lower storage levels and higher AECO benchmark pricing. The decrease for the third quarter of 2022 from the second quarter of 2022 primarily reflected lower AECO benchmark pricing.

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

	Three Months Ended					
(Quarterly average)		**Sep 30 2022**		Jun 30 2022		Sep 30 2021
Wellhead Price (1)						
Light and medium crude oil and NGLs ($/bbl)	**$**	**82.26**	$	105.36	$	63.88
Pelican Lake heavy crude oil ($/bbl)	**$**	**91.98**	$	121.88	$	71.92
Primary heavy crude oil ($/bbl)	**$**	**89.80**	$	122.14	$	68.72
Bitumen (thermal oil) ($/bbl)	**$**	**80.74**	$	112.92	$	64.81
Natural gas ($/Mcf)	**$**	**6.51**	$	7.90	$	4.12

(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 57% to average $132.96 per bbl for the nine months ended September 30, 2022 from $84.86 per bbl for the nine months ended September 30, 2021. International realized crude oil and NGLs prices increased 28% to average $120.09 per bbl for the third quarter of 2022 from $93.72 per bbl for the third quarter of 2021, and decreased 17% from $144.82 per bbl for the second 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 nine months ended September 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			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 19.78**	$ 26.24	$ 10.02	**$ 21.53**	$ 8.29
International average	**$ 11.24**	$ 5.78	$ 2.44	**$ 6.30**	$ 1.95
North Sea	**$ 0.86**	$ 0.24	$ 0.22	**$ 0.38**	$ 0.19
Offshore Africa	**$ 14.61**	$ 12.36	$ 4.27	**$ 10.47**	$ 3.92
Crude oil and NGLs average	**$ 19.48**	$ 25.01	$ 9.46	**$ 20.75**	$ 7.86
Natural gas ($/Mcf) [1]					
North America	**$ 0.61**	$ 0.89	$ 0.22	**$ 0.64**	$ 0.17
Offshore Africa	**$ 1.73**	$ 2.20	$ 0.31	**$ 1.62**	$ 0.29
Natural gas average	**$ 0.61**	$ 0.89	$ 0.22	**$ 0.65**	$ 0.17
Average ($/BOE) [1]	**$ 12.88**	$ 17.03	$ 6.45	**$ 13.94**	$ 5.44

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

North America

North America crude oil and NGLs and natural gas royalties for the three and nine months ended September 30, 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 nine months ended September 30, 2022 compared with 14% of product sales for the nine months ended September 30, 2021. Crude oil and NGLs royalty rates averaged approximately 24% of product sales for the third quarter of 2022 compared with 15% for the third quarter of 2021 and 23% for the second quarter of 2022. The increase in royalty rates for the three and nine months ended September 30, 2022 from the comparable periods in 2021 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 nine months ended September 30, 2022 compared with 5% of product sales for the nine months ended September 30, 2021. Natural gas royalty rates averaged approximately 9% of product sales for the third quarter of 2022 compared with 5% for the third quarter of 2021 and 11% for the second quarter of 2022. The increase in royalty rates for the three and nine months ended September 30, 2022 from the comparable periods in 2021 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 8% for the nine months ended September 30, 2022, compared with 5% of product sales for the nine months ended September 30, 2021. Royalty rates as a percentage of product sales averaged approximately 12% for the third quarter of 2022 compared with 5% of product sales for the third quarter of 2021 and 9% for the second 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			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 15.98**	$ 17.45	$ 13.33	**$ 16.06**	$ 12.98
International average	**$ 40.86**	$ 53.02	$ 33.25	**$ 42.49**	$ 33.21
North Sea	**$ 115.41**	$ 84.38	$ 55.90	**$ 81.52**	$ 49.83
Offshore Africa	**$ 16.64**	$ 15.73	$ 14.53	**$ 15.05**	$ 14.49
Crude oil and NGLs average	**$ 16.86**	$ 19.58	$ 14.78	**$ 17.41**	$ 14.36
Natural gas ($/Mcf) (1)					
North America	**$ 1.13**	$ 1.15	$ 1.14	**$ 1.18**	$ 1.18
International average	**$ 4.99**	$ 4.12	$ 6.51	**$ 4.57**	$ 4.91
North Sea	**$ 12.67**	$ 6.60	$ 8.86	**$ 8.68**	$ 6.66
Offshore Africa	**$ 4.27**	$ 3.78	$ 5.76	**$ 3.99**	$ 4.37
Natural gas average	**$ 1.16**	$ 1.17	$ 1.17	**$ 1.21**	$ 1.21
Average ($/BOE) (1)	**$ 12.68**	$ 14.44	$ 11.91	**$ 13.28**	$ 11.85

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

North America

North America crude oil and NGLs production expense for the nine months ended September 30, 2022 averaged $16.06 per bbl, an increase of 24% from $12.98 per bbl for the nine months ended September 30, 2021. North America crude oil and NGLs production expense for the third quarter of 2022 of $15.98 per bbl increased 20% from $13.33 per bbl for the third quarter of 2021 and decreased 8% from $17.45 per bbl for the second quarter of 2022. The increase in crude oil and NGLs production expense per bbl for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected higher energy costs. The decrease in crude oil and NGLs production expense per bbl for the third quarter of 2022 from the second quarter of 2022 primarily reflected lower natural gas costs in the third quarter and the Company's strong focus on cost control.

North America natural gas production expense averaged $1.18 per Mcf for the nine months ended September 30, 2022 and averaged $1.13 per Mcf for the third quarter of 2022. North America production expense was comparable with previous periods reported, reflecting the Company's strong focus on cost control.

International

International crude oil and NGLs production expense for the nine months ended September 30, 2022 averaged $42.49 per bbl, an increase of 28% from $33.21 per bbl for the nine months ended September 30, 2021. International crude oil and NGLs production expense for the third quarter of 2022 of $40.86 per bbl increased 23% from $33.25 per bbl for the third quarter of 2021 and decreased 23% from $53.02 per bbl for the second quarter of 2022. Fluctuations in crude oil and NGLs production expense per bbl for the three and nine months ended September 30, 2022 from the comparable periods primarily reflected the timing of liftings from various fields that have different cost structures, the impact of maintenance activities, and fluctuations in foreign exchange.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
North America	**$ 913**	$ 855	$ 881	**$ 2,646**	$ 2,630
North Sea	**15**	50	40	**94**	127
Offshore Africa	**39**	42	48	**132**	123
Depletion, Depreciation and Amortization	**$ 967**	$ 947	$ 969	**$ 2,872**	$ 2,880
$/BOE (1)	**$ 12.48**	$ 12.14	$ 13.70	**$ 12.34**	$ 13.66

(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 nine months ended September 30, 2022 of $12.34 per BOE decreased 10% from $13.66 per BOE for the nine months ended September 30, 2021. Depletion, depreciation and amortization expense for the third quarter of 2022 of $12.48 per BOE decreased 9% from $13.70 per BOE for the third quarter of 2021 and increased 3% from $12.14 per BOE for the second quarter of 2022. The decrease in depletion, depreciation and amortization expense per BOE for the three and nine months ended September 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. The increase in depletion, depreciation and amortization expense per BOE for the third quarter of 2022 from the second quarter of 2022 primarily reflected the product sales mix in the North America Exploration and Production segment.

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

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
North America	**$ 50**	$ 35	$ 26	**$ 120**	$ 76
North Sea	**10**	6	6	**23**	16
Offshore Africa	**2**	1	1	**5**	4
Asset Retirement Obligation Accretion	**$ 62**	$ 42	$ 33	**$ 148**	$ 96
$/BOE (1)	**$ 0.80**	$ 0.55	$ 0.45	**$ 0.64**	$ 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 nine months ended September 30, 2022 of $0.64 per BOE increased 42% from $0.45 per BOE for the nine months ended September 30, 2021. Asset retirement obligation accretion expense for the third quarter of 2022 of $0.80 per BOE increased 78% from $0.45 per BOE for the third quarter of 2021 and increased 45% from $0.55 per BOE for the second quarter of 2022. The increase in asset retirement obligation accretion expense per BOE for the three and nine months ended September 30, 2022 from the comparable periods primarily reflected the cost estimate and discount rate revisions made to the asset retirement obligation in the fourth quarter of 2021 and the second quarter of 2022.

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 of 487,553 bbl/d in the third quarter of 2022 reflected strong operational performance across the Oil Sands Mining and Upgrading segment, with record sales volumes of 489,146 bbl/d achieved during the quarter.

The Company incurred production costs of $1,005 million for the third quarter of 2022, an 18% increase from $855 million for the third quarter of 2021, and a 7% decrease from $1,077 million for the second quarter of 2022. The increase from the third quarter of 2021 primarily reflected higher energy costs. The decrease from the second quarter of 2022 primarily reflected the completion of planned turnaround activities in the second quarter, together with lower energy costs.

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

($/bbl)	Three Months Ended			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Realized SCO sales price [(1)]	**$ 120.91**	$ 137.60	$ 81.54	**$ 122.45**	$ 74.00
Bitumen value for royalty purposes [(2)]	**$ 82.19**	$ 110.96	$ 62.28	**$ 91.69**	$ 55.54
Bitumen royalties [(3)]	**$ 24.87**	$ 31.63	$ 8.21	**$ 22.85**	$ 5.67
Transportation [(1)]	**$ 1.55**	$ 2.05	$ 1.14	**$ 1.69**	$ 1.16

(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 $122.45 per bbl for the nine months ended September 30, 2022, an increase of 65% from $74.00 per bbl for the nine months ended September 30, 2021. The realized SCO sales price averaged $120.91 per bbl for the third quarter of 2022, an increase of 48% from $81.54 per bbl for the third quarter of 2021 and a decrease of 12% from $137.60 per bbl for the second quarter of 2022. The increase in the realized SCO sales price for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected the increase in WTI benchmark pricing, together with a higher SCO differential due to strong North American diesel demand. The decrease for the third quarter of 2022 from the second quarter of 2022 primarily reflected the decrease in WTI benchmark pricing.

The increase in bitumen royalties per bbl for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected the impact of Horizon reaching full payout in the second quarter of 2022, together with higher prevailing bitumen pricing and higher sliding scale royalty rates. The decrease for the third quarter of 2022 from the second quarter of 2022 primarily reflected the impact of lower prevailing bitumen pricing.

Transportation expense averaged $1.69 per bbl for the nine months ended September 30, 2022, an increase of 46% from $1.16 per bbl for the nine months ended September 30, 2021. Transportation expense averaged $1.55 per bbl for the third quarter of 2022, an increase of 36% from $1.14 per bbl for the third quarter of 2021 and a decrease of 24% from $2.05 per bbl for the second quarter of 2022. The increase in transportation expense per bbl for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected the impact of higher pipeline tolls. The decrease for the third quarter of 2022 from the second quarter of 2022 primarily reflected the impact of higher sales volumes.

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 **Sep 30 2022**	Three Months Ended Jun 30 2022	Three Months Ended Sep 30 2021	Nine Months Ended **Sep 30 2022**	Nine Months Ended Sep 30 2021
Production costs, excluding natural gas costs	**$ 935**	$ 979	$ 802	**$ 2,810**	$ 2,380
Natural gas costs	**70**	98	53	**249**	163
Production costs	**$ 1,005**	$ 1,077	$ 855	**$ 3,059**	$ 2,543

($/bbl)	Three Months Ended **Sep 30 2022**	Three Months Ended Jun 30 2022	Three Months Ended Sep 30 2021	Nine Months Ended **Sep 30 2022**	Nine Months Ended Sep 30 2021
Production costs, excluding natural gas costs (1)	**$ 20.77**	$ 30.69	$ 18.63	**$ 24.10**	$ 20.05
Natural gas costs (2)	**1.58**	3.07	1.23	**2.14**	1.37
Production costs (3)	**$ 22.35**	$ 33.76	$ 19.86	**$ 26.24**	$ 21.42
Sales volumes (bbl/d)	**489,146**	350,500	467,772	**427,165**	434,848

(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 nine months ended September 30, 2022 of $26.24 per bbl increased 23% from $21.42 per bbl for the nine months ended September 30, 2021. Production costs for the third quarter of 2022 averaged $22.35 per bbl, an increase of 13% from $19.86 per bbl for the third quarter of 2021 and a decrease of 34% from $33.76 per bbl for the second quarter of 2022. The increase in production costs per bbl for the three and nine months ended September 30, 2022 from the comparable periods in 2021 primarily reflected higher energy costs. The decrease in production costs per bbl for the third quarter of 2022 from the second quarter of 2022 primarily reflected higher production volumes due to the completion of planned turnaround activities in the second quarter, together with lower energy costs.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended **Sep 30 2022**	Three Months Ended Jun 30 2022	Three Months Ended Sep 30 2021	Nine Months Ended **Sep 30 2022**	Nine Months Ended Sep 30 2021
Depletion, depreciation and amortization	**$ 484**	$ 412	$ 469	**$ 1,341**	$ 1,360
$/bbl (1)	**$ 10.75**	$ 12.92	$ 10.90	**$ 11.50**	$ 11.45

(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 nine months ended September 30, 2022 of $11.50 per bbl was comparable with $11.45 per bbl for the nine months ended September 30, 2021. Depletion, depreciation and amortization expense for the third quarter of 2022 of $10.75 per bbl was comparable with $10.90 per bbl for the third quarter of 2021, and decreased 17% from $12.92 per bbl for the second quarter of 2022. The decrease in depletion, depreciation and amortization expense on a per barrel basis for the third quarter of 2022 from the second quarter of 2022 primarily reflected the impact of higher sales volumes during the third quarter of 2022.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Asset retirement obligation accretion	**$ 20**	$ 16	$ 14	**$ 51**	$ 43
$/bbl (1)	**$ 0.43**	$ 0.48	$ 0.33	**$ 0.43**	$ 0.36

(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 nine months ended September 30, 2022 of $0.43 per bbl increased 19% from $0.36 per bbl for the nine months ended September 30, 2021. Asset retirement obligation accretion expense for the third quarter of 2022 of $0.43 per bbl increased 30% from $0.33 per bbl for the third quarter of 2021, and decreased 10% from $0.48 per bbl for the second quarter of 2022. The increase in asset retirement obligation accretion expense on a per barrel basis from comparable periods in 2021 primarily reflected the impact of cost estimate and discount rate revisions made to the asset retirement obligation during the second quarter of 2022. The decrease in asset retirement obligation accretion expense on a per barrel basis for the third quarter of 2022 from the second quarter of 2022 primarily reflected the impact of higher sales volumes during the third quarter of 2022.

MIDSTREAM AND REFINING

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Product sales					
Midstream activities	**$ 21**	$ 18	$ 21	**$ 59**	$ 61
NWRP, refined product sales and other	**134**	318	179	**701**	481
Segmented revenue	**155**	336	200	**760**	542
Less:					
NWRP, refining toll	**66**	63	46	**190**	176
Midstream activities	**6**	7	4	**18**	16
Production expense	**72**	70	50	**208**	192
NWRP, transportation and feedstock costs	**113**	244	146	**536**	385
Depreciation	**3**	4	4	**11**	11
Income from NWRP	**—**	—	—	**—**	(400)
Segmented (loss) earnings	**$ (33)**	$ 18	$ —	**$ 5**	$ 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 third quarter of 2022, production of ultra-low sulphur diesel and other refined products averaged 32,252 BOE/d (8,063 BOE/d to the Company), (three months ended September 30, 2021 – 77,387 BOE/d; 19,347 BOE/d to the Company), reflecting turnaround activities during the quarter.

During the third quarter of 2022, NWRP extended its $3,000 million syndicated credit facility and increased it to $3,175 million. The revolving portion of the credit facility was increased to $2,175 million, with $118 million maturing in June 2023, and $2,057 million maturing in June 2025. The $1,000 million non-revolving portion of the credit facility was extended, with $60 million maturing in June 2023, and $940 million maturing in June 2025. During the third quarter of 2022, NWRP also entered into a $150 million facility to support letters of credit.

As at September 30, 2022, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $588 million (December 31, 2021 – $562 million). For the three months ended September 30, 2022, the Company's unrecognized share of the equity loss was $1 million (nine months ended September 30, 2022 – unrecognized equity loss of $26 million; three months ended September 30, 2021 – unrecognized equity loss of $21 million; nine months ended September 30, 2021 – recovery of unrecognized equity losses of $3 million and partnership distributions of $400 million).

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2022	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Expense ($ millions)	**$ 94**	$ 97	$ 87	**$ 307**	$ 269
$/BOE [1]	**$ 0.76**	$ 0.89	$ 0.77	**$ 0.88**	$ 0.82
Sales volumes (BOE/d) [2]	**1,331,189**	1,207,485	1,236,813	**1,279,771**	1,207,367

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

(2) Total Company sales volumes.

Administration expense for the nine months ended September 30, 2022 of $0.88 per BOE increased 7% from $0.82 per BOE for the nine months ended September 30, 2021. Administration expense for the third quarter of 2022 of $0.76 per BOE was comparable with $0.77 per BOE for the third quarter of 2021 and decreased 15% from $0.89 per BOE for the second quarter of 2022. The increase in administration expense per BOE for the nine months ended September 30, 2022 from 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 third quarter of 2022 from the second quarter of 2022 was primarily due to higher sales volumes.

SHARE-BASED COMPENSATION

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
(Recovery) expense	**$ (4)**	$ (45)	$ 57	**$ 485**	$ 323

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 $485 million share-based compensation expense for the nine months ended September 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.

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except effective interest rate)	Three Months Ended **Sep 30 2022**	Three Months Ended Jun 30 2022	Three Months Ended Sep 30 2021	Nine Months Ended **Sep 30 2022**	Nine Months Ended Sep 30 2021
Interest and other financing expense	**$ 150**	$ 160	$ 178	**$ 473**	$ 540
Interest income and other (1)	**18**	6	3	**28**	30
Interest on long-term debt and lease liabilities (1)	**$ 168**	$ 166	$ 181	**$ 501**	$ 570
Average current and long-term debt (2)	**$ 13,714**	$ 14,107	$ 18,165	**$ 14,257**	$ 19,885
Average lease liabilities (2)	**1,526**	1,540	1,599	**1,539**	1,633
Average long-term debt and lease liabilities (2)	**$ 15,240**	$ 15,647	$ 19,764	**$ 15,796**	$ 21,518
Average effective interest rate (3) (4)	**4.3%**	4.1%	3.6%	**4.1%**	3.5%
Interest and other financing expense per $/BOE (5)	**$ 1.23**	$ 1.46	$ 1.56	**$ 1.36**	$ 1.64
Sales volumes (BOE/d) (6)	**1,331,189**	1,207,485	1,236,813	**1,279,771**	1,207,367

(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 nine months ended September 30, 2022 decreased 17% to $1.36 per BOE from $1.64 per BOE for the nine months ended September 30, 2021. Interest and other financing expense per BOE for the third quarter of 2022 decreased 21% to $1.23 per BOE from $1.56 per BOE for the third quarter of 2021 and decreased 16% from $1.46 per BOE for the second quarter of 2022. The decrease in interest and other financing expense per BOE for the three and nine months ended September 30, 2022 from the comparable periods was primarily due to lower average debt levels and higher sales volumes.

The Company's average effective interest rate for the three and nine months ended September 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 during the first half of 2022.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Foreign currency contracts	**$ (43)**	$ (19)	$ (18)	**$ (40)**	$ 12
Natural gas financial instruments (1)	**(3)**	17	14	**19**	11
Crude oil and NGLs financial instruments (1)	**2**	9	—	**16**	—
Net realized (gain) loss	**(44)**	7	(4)	**(5)**	23
Foreign currency contracts	**—**	(1)	(1)	**(14)**	(10)
Natural gas financial instruments (1)	**(44)**	(16)	(18)	**(28)**	21
Crude oil and NGLs financial instruments (1)	**(4)**	(4)	—	**(1)**	—
Net unrealized (gain) loss	**(48)**	(21)	(19)	**(43)**	11
Net (gain) loss	**$ (92)**	$ (14)	$ (23)	**$ (48)**	$ 34

(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 nine months ended September 30, 2022, net realized risk management gains were related to the settlement of foreign currency contracts, partially offset by losses on natural gas financial instruments, and crude oil and NGLs financial instruments. The Company recorded a net unrealized gain of $43 million ($36 million after-tax of $7 million) on its risk management activities for the nine months ended September 30, 2022, including an unrealized gain of $48 million ($37 million after-tax of $11 million) for the third quarter of 2022 (three months ended June 30, 2022 – unrealized gain of $21 million, $16 million after-tax of $5 million; three months ended September 30, 2021 – unrealized gain of $19 million, $15 million after-tax of $4 million).

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

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Net realized (gain) loss	**$ (49)**	$ (93)	$ 84	**$ (132)**	$ 105
Net unrealized loss (gain)	**785**	426	197	**1,055**	(126)
Net loss (gain) (1)	**$ 736**	$ 333	$ 281	**$ 923**	$ (21)

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

The net realized foreign exchange gain for the nine months ended September 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 nine months ended September 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 September 30, 2022 was US$0.7300 (June 30, 2022 – US$0.7769, September 30, 2021 – US$0.7843).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended **Sep 30 2022**	Jun 30 2022	Sep 30 2021	Nine Months Ended **Sep 30 2022**	Sep 30 2021
North America [1]	**$ 755**	$ 855	$ 541	**$ 2,444**	$ 1,150
North Sea	**14**	15	4	**36**	10
Offshore Africa	**21**	18	7	**51**	18
PRT [2] – North Sea	**(36)**	6	(5)	**(37)**	(22)
Other taxes	**3**	5	4	**13**	9
Current income tax	**757**	899	551	**2,507**	1,165
Deferred income tax	**194**	131	56	**450**	206
Income tax	**$ 951**	$ 1,030	$ 607	**$ 2,957**	$ 1,371
Earnings before taxes	**$ 3,765**	$ 4,532	$ 2,809	**$ 12,374**	$ 6,501
Effective tax rate on net earnings [3]	**25%**	23%	22%	**24%**	21%
Income tax	**$ 951**	$ 1,030	$ 607	**$ 2,957**	$ 1,371
Tax effect on non-operating items [4]	**(15)**	(9)	(6)	**(16)**	5
Current PRT - North Sea	**36**	(6)	5	**37**	22
Other taxes	**(3)**	(5)	(4)	**(13)**	(9)
Effective tax on adjusted net earnings	**$ 969**	$ 1,010	$ 602	**$ 2,965**	$ 1,389
Adjusted net earnings from operations [5]	**$ 3,493**	$ 3,800	$ 2,095	**$ 10,669**	$ 4,794
Effective tax on adjusted net earnings	**969**	1,010	602	**2,965**	1,389
Adjusted net earnings from operations, before taxes	**$ 4,462**	$ 4,810	$ 2,697	**$ 13,634**	$ 6,183
Effective tax rate on adjusted net earnings from operations [6] [7]	**22%**	21%	22%	**22%**	22%

(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 nine months ended September 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 nine months ended September 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 Sep 30 2022	Three Months Ended Jun 30 2022	Three Months Ended Sep 30 2021	Nine Months Ended Sep 30 2022	Nine Months Ended Sep 30 2021
Exploration and Evaluation					
Net expenditures	**$ 2**	$ 1	$ 5	**$ 25**	$ 10
Net property acquisitions (dispositions)	**1**	1	(1)	**(1)**	(5)
Total Exploration and Evaluation	**3**	2	4	**24**	5
Property, Plant and Equipment					
Net property acquisitions	**1**	30	131	**513**	139
Well drilling, completion and equipping	**410**	384	232	**1,138**	722
Production and related facilities	**378**	293	244	**882**	622
Other	**15**	16	12	**44**	41
Total Property, Plant and Equipment	**804**	723	619	**2,577**	1,524
Total Exploration and Production	**807**	725	623	**2,601**	1,529
Oil Sands Mining and Upgrading					
Project costs	**77**	74	69	**196**	171
Sustaining capital	**223**	375	233	**804**	765
Turnaround costs	**18**	193	19	**271**	122
Other [3]	**3**	2	3	**6**	330
Total Oil Sands Mining and Upgrading	**321**	644	324	**1,277**	1,388
Midstream and Refining	**2**	3	3	**7**	6
Head office	**5**	8	7	**18**	16
Abandonments expenditures, net [2]	**114**	70	54	**251**	165
Net capital expenditures	**$ 1,249**	$ 1,450	$ 1,011	**$ 4,154**	$ 3,104
By segment					
North America	**$ 736**	$ 675	$ 564	**$ 2,456**	$ 1,361
North Sea	**40**	27	49	**78**	125
Offshore Africa	**31**	23	10	**67**	43
Oil Sands Mining and Upgrading	**321**	644	324	**1,277**	1,388
Midstream and Refining	**2**	3	3	**7**	6
Head office	**5**	8	7	**18**	16
Abandonments expenditures, net [2]	**114**	70	54	**251**	165
Net capital expenditures	**$ 1,249**	$ 1,450	$ 1,011	**$ 4,154**	$ 3,104

(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 nine months ended September 30, 2022 were $4,154 million compared with $3,104 million for the nine months ended September 30, 2021. Net capital expenditures for the nine months ended September 30, 2022 included base capital expenditures [1] of $3,106 million and strategic growth capital expenditures [1] of $536 million, in accordance with the Company's capital budget. The Company also completed strategic acquisitions [1] of $512 million during the nine months ended September 30, 2022. Net capital expenditures were $1,249 million for the third quarter of 2022 compared with $1,011 million for the third quarter of 2021 and $1,450 million for the second 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			Nine Months Ended	
(number of net wells)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Net successful natural gas wells	**14**	20	9	**57**	40
Net successful crude oil wells [(3)]	**98**	83	56	**237**	127
Dry wells	**—**	1	1	**1**	1
Total	**112**	104	66	**295**	168
Success rate	**100%**	99%	98%	**99%**	99%

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

(2) In addition, during the third quarter of 2022, on a net basis, the Company drilled 1 service well in the Oil Sands Mining and Upgrading segment, 12 service wells in the Company's thermal oil projects and 1 service well in Northwest Alberta. During the nine months ended September 30, 2022, on a net basis, the Company drilled 351 stratigraphic and 4 service wells in the Oil Sands Mining and Upgrading segment, 18 stratigraphic and 34 service wells in the Company's thermal oil projects, and 2 service wells in Northwest Alberta.

(3) Includes bitumen wells.

North America

During the third quarter of 2022, the Company drilled 14 net natural gas wells, 47 net primary heavy crude oil wells, 38 net bitumen (thermal oil) wells and 13 net light crude oil wells.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2022**	Jun 30 2022	Dec 31 2021	Sep 30 2021
Adjusted working capital [(1)]	**$ (606)**	$ (99)	$ (480)	$ 423
Long-term debt, net [(2)]	**$ 12,384**	$ 12,369	$ 13,950	$ 15,880
Shareholders’ equity	**$ 38,139**	$ 39,340	$ 36,945	$ 35,526
Debt to book capitalization [(2)]	**24.5%**	23.9%	27.4%	30.9%
After-tax return on average capital employed [(3)]	**24.0%**	22.7%	15.6%	12.1%

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

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

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

As at September 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.
  - Subsequent to September 30, 2022, the $500 million revolving credit facility was extended to February 2024.
  - 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 third quarter of 2022, the Company repaid through market purchases $341 million of medium-term notes with interest rates ranging from 1.45% to 3.55%, originally due between 2023 and 2028 (nine months ended September 30, 2022 - $480 million).
  - Subsequent to September 30, 2022, the Company repaid through market purchases an additional $5 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 September 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 $6,488 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 September 30, 2022, the Company had no cross currency swap contracts outstanding. As at September 30, 2022, there were no foreign currency contracts designated as cash flow hedges.

Long-term debt, net was $12,384 million as at September 30, 2022, resulting in a debt to book capitalization ratio of 24.5% (December 31, 2021 – 27.4%); this ratio was slightly 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 September 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 September 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 September 30, 2022 are discussed in note 15 to the financial statements.

As at September 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)]	$ 1,370	$ 1,439	$ 3,797	$ 6,416
Other long-term liabilities [(2)]	$ 239	$ 159	$ 426	$ 752
Interest and other financing expense [(3)]	$ 623	$ 592	$ 1,472	$ 3,886

(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, $193 million; one to less than two years, $159 million; two to less than five years, $426 million; and thereafter, $752 million.

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

Share Capital

As at September 30, 2022, there were 1,109,447,000 common shares outstanding (December 31, 2021 – 1,168,369,000 common shares) and 33,932,000 stock options outstanding. As at November 1, 2022, the Company had 1,107,031,000 common shares outstanding and 32,845,000 stock options outstanding.

On November 2, 2022, the Board of Directors approved a 13% increase in the quarterly dividend to $0.85 per common share, beginning with the dividend payable on January 5, 2023.

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

On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share. 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 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 nine months ended September 30, 2022, the Company purchased 67,738,200 common shares at a weighted average price of $71.23 per common share for a total cost of $4,825 million. Retained earnings were reduced by $4,211 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2022, the Company purchased 3,450,000 common shares at a weighted average price of $76.64 per common share for a total cost of $264 million.

COMMITMENTS AND CONTINGENCIES

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

($ millions)	Remaining 2022	2023	2024	2025	2026	Thereafter
Product transportation and processing [1]	$ 284	$ 1,119	$ 1,194	$ 1,070	$ 1,008	$ 12,013
North West Redwater Partnership service toll [2]	$ 36	$ 144	$ 145	$ 143	$ 124	$ 4,678
Offshore vessels and equipment	$ 41	$ 42	$ —	$ —	$ —	$ —
Field equipment and power	$ 17	$ 21	$ 21	$ 21	$ 21	$ 226
Other	$ 8	$ 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 $2,534 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 nine months ended September 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			Nine Months Ended	
($ millions)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Net earnings	**$ 2,814**	$ 3,502	$ 2,202	**$ 9,417**	$ 5,130
Share-based compensation, net of tax (1)	**(8)**	(47)	54	**471**	312
Unrealized risk management (gain) loss, net of tax (2)	**(37)**	(16)	(15)	**(36)**	6
Unrealized foreign exchange loss (gain), net of tax (3)	**785**	426	197	**1,055**	(126)
Realized foreign exchange (gain) loss, net of tax (4)	**—**	(69)	118	**(69)**	118
Gain on acquisitions, net of tax (5)	**—**	—	(478)	**—**	(478)
(Gain) loss from investments, net of tax (6)	**(36)**	25	35	**(94)**	(129)
Other, net of tax (7)	**(25)**	(21)	(18)	**(75)**	(39)
Non-operating items, net of tax	**679**	298	(107)	**1,252**	(336)
Adjusted net earnings from operations	**$ 3,493**	$ 3,800	$ 2,095	**$ 10,669**	$ 4,794

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings. Pre-tax share-based compensation for the three months ended September 30, 2022 was a recovery of $4 million (three months ended June 30, 2022 – $45 million recovery, three months ended September 30, 2021 – $57 million expense; nine months ended September 30, 2022 – $485 million expense, nine months ended September 30, 2021 – $323 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 September 30, 2022 was $48 million (three months ended June 30, 2022 – $21 million gain, three months ended September 30, 2021 – $19 million gain; nine months ended September 30, 2022 – $43 million gain, nine months ended September 30, 2021 – $11 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) Consists of the realized foreign exchange gain on settlement of cross currency swap and the realized foreign exchange loss on repayment of US dollar debt securities. 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. During the third quarter of 2021, the Company repaid US$500 million of 3.45% debt securities, originally due November 2021. Pre- and after-tax amounts for these realized foreign exchange gains and losses are the same.

(5) During the third quarter of 2021, the Company completed two acquisitions resulting in a gain of $478 million.

(6) The Company's investments have been accounted for at fair value through profit and loss and are measured each period with (gains) losses recognized in net earnings. There is zero net tax impact on these (gains) losses from investments.

(7) Other relates to the impact of government grant income under the provincial well-site rehabilitation programs. Pre-tax other for the three months ended September 30, 2022 was $33 million (three months ended June 30, 2022 – $27 million, three months ended September 30, 2021 – $23 million; nine months ended September 30, 2022 – $98 million, nine months ended September 30, 2021 – $50 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			Nine Months Ended	
($ millions)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Cash flows from operating activities	**$ 6,098**	$ 5,896	$ 4,290	**$ 14,847**	$ 9,766
Net change in non-cash working capital	**(1,024)**	(478)	(691)	**438**	(544)
Abandonment expenditures, net (1)	**114**	70	54	**251**	165
Movements in other long-term assets (2)	**20**	(56)	(19)	**79**	8
Adjusted funds flow	**$ 5,208**	$ 5,432	$ 3,634	**$ 15,615**	$ 9,395

(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			Nine Months Ended	
($ millions)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Abandonment expenditures	**$ 147**	$ 97	$ 77	**$ 349**	$ 215
Government grants for abandonment expenditures	**(33)**	(27)	(23)	**(98)**	(50)
Abandonment expenditures, net	**$ 114**	$ 70	$ 54	**$ 251**	$ 165

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			Nine Months Ended	
($ millions, except bbl/d and $/bbl)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Crude oil and NGLs (bbl/d)					
North America	**469,532**	475,744	448,948	**479,936**	464,888
International					
North Sea	**4,229**	16,530	16,028	**10,642**	18,128
Offshore Africa	**13,020**	13,902	19,402	**15,137**	16,090
Total International	**17,249**	30,432	35,430	**25,779**	34,218
Total sales volumes	**486,781**	506,176	484,378	**505,715**	499,106
Crude oil and NGLs sales (1)	**$ 4,813**	$ 6,871	$ 3,810	**$ 17,567**	$ 10,838
Less: Blending costs (2)	**1,010**	1,561	777	**4,037**	2,590
Realized crude oil and NGLs sales	**$ 3,803**	$ 5,310	$ 3,033	**$ 13,530**	$ 8,248
Realized price ($/bbl)	**$ 84.91**	$ 115.26	$ 68.06	**$ 97.99**	$ 60.53

(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			Nine Months Ended	
($ millions, except BOE/d and $/BOE)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Barrels of oil equivalent (BOE/d)					
North America	**822,257**	823,931	731,962	**824,102**	735,877
International					
North Sea	**4,447**	16,845	16,427	**10,977**	18,693
Offshore Africa	**15,339**	16,210	20,652	**17,527**	17,949
Total International	**19,786**	33,055	37,079	**28,504**	36,642
Total sales volumes	**842,043**	856,986	769,041	**852,606**	772,519
Barrels of oil equivalent sales (1)	**$ 6,100**	$ 8,388	$ 4,460	**$ 21,320**	$ 12,444
Less: Blending costs (2)	**1,010**	1,561	777	**4,037**	2,590
Less: Sulphur income	**(25)**	(41)	(3)	**(85)**	(9)
Realized barrels of oil equivalent sales	**$ 5,115**	$ 6,868	$ 3,686	**$ 17,368**	$ 9,863
Realized price ($/BOE)	**$ 66.04**	$ 88.07	$ 52.09	**$ 74.62**	$ 46.77

(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			Nine Months Ended	
($ millions, except $ per unit amounts)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Transportation, blending and feedstock [1]	**$ 1,292**	$ 1,849	$ 1,025	**$ 4,895**	$ 3,319
Less: Blending costs	**1,010**	1,561	777	**4,037**	2,590
Transportation	**$ 282**	$ 288	$ 248	**$ 858**	$ 729
Transportation ($/BOE)	**$ 3.64**	$ 3.70	$ 3.50	**$ 3.68**	$ 3.45
Amounts attributed to crude oil and NGLs	**$ 184**	$ 190	$ 178	**$ 571**	$ 523
Transportation ($/bbl)	**$ 4.10**	$ 4.13	$ 4.00	**$ 4.14**	$ 3.84
Amounts attributed to natural gas	**$ 98**	$ 98	$ 70	**$ 287**	$ 206
Transportation ($/Mcf)	**$ 0.51**	$ 0.52	$ 0.44	**$ 0.50**	$ 0.46

(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			Nine Months Ended	
($ millions, except $/bbl and royalty rates)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Crude oil and NGLs sales [1]	**$ 4,622**	$ 6,470	$ 3,506	**$ 16,631**	$ 10,047
Less: Blending costs [2]	**1,010**	1,561	777	**4,037**	2,590
Realized crude oil and NGLs sales	**$ 3,612**	$ 4,909	$ 2,729	**$ 12,594**	$ 7,457
Realized crude oil and NGLs prices ($/bbl)	**$ 83.62**	$ 113.37	$ 66.03	**$ 96.11**	$ 58.74
Crude oil and NGLs royalties [3]	**$ 854**	$ 1,136	$ 414	**$ 2,820**	$ 1,052
Crude oil and NGLs royalty rates	**24%**	23%	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			Nine Months Ended	
($ millions, except for bbl/d and $/bbl)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
SCO sales volumes (bbl/d)	**489,146**	350,500	467,772	**427,165**	434,848
Crude oil and NGLs sales [1]	**$ 6,056**	$ 4,962	$ 3,848	**$ 15,869**	$ 9,625
Less: Blending and feedstock costs	**615**	573	339	**1,589**	841
Realized SCO sales	**$ 5,441**	$ 4,389	$ 3,509	**$ 14,280**	$ 8,784
Realized SCO sales price ($/bbl)	**$ 120.91**	$ 137.60	$ 81.54	**$ 122.45**	$ 74.00
Transportation, blending and feedstock [2]	**$ 684**	$ 638	$ 387	**$ 1,785**	$ 978
Less: Blending and feedstock costs	**615**	573	339	**1,589**	841
Transportation	**$ 69**	$ 65	$ 48	**$ 196**	$ 137
Transportation ($/bbl)	**$ 1.55**	$ 2.05	$ 1.14	**$ 1.69**	$ 1.16

(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 proceeds from investment, 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			Nine Months Ended	
($ millions)	**Sep 30 2022**	Jun 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Cash flows used in investing activities	**$ 1,129**	$ 1,345	$ 721	**$ 3,725**	$ 2,088
Net change in non-cash working capital	**6**	35	108	**178**	168
Proceeds from investment	**—**	—	128	**—**	128
Repayment of NWRP subordinated debt advances	**—**	—	—	**—**	555
Capital expenditures	**1,135**	1,380	957	**3,903**	2,939
Abandonment expenditures, net [1]	**114**	70	54	**251**	165
Net capital expenditures [2]	**$ 1,249**	$ 1,450	$ 1,011	**$ 4,154**	$ 3,104

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

(2) For the nine months ended September 30, 2022, includes base capital expenditures of $3,106 million, net property, plant and equipment acquisitions and net exploration and evaluation asset dispositions of $512 million, and strategic growth capital expenditures of $536 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)	**Sep 30 2022**	Jun 30 2022	Dec 31 2021	Sep 30 2021
Undrawn bank credit facilities	**$ 5,520**	$ 5,520	$ 6,098	$ 4,959
Cash and cash equivalents	**565**	233	744	894
Investments	**403**	367	309	306
Liquidity	**$ 6,488**	$ 6,120	$ 7,151	$ 6,159

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)	**Sep 30 2022**	Jun 30 2022	Dec 31 2021	Sep 30 2021
Interest adjusted after-tax return:				
Net earnings, 12 months trailing	**$ 11,951**	$ 11,339	$ 7,664	$ 5,879
Interest and other financing expense, net of tax, 12 months trailing (1)	**497**	517	547	552
Interest adjusted after-tax return	**$ 12,448**	$ 11,856	$ 8,211	$ 6,431
12 months average current portion long-term debt (2)	**$ 1,478**	$ 1,664	$ 1,483	$ 1,449
12 months average long-term debt (2)	**12,707**	13,597	16,769	18,240
12 months average common shareholders' equity (2)	**37,688**	36,902	34,458	33,502
12 months average capital employed	**$ 51,873**	$ 52,163	$ 52,710	$ 53,191
After-tax return on average capital employed	**24.0%**	22.7%	15.6%	12.1%

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

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

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Sep 30 2022	Dec 31 2021
ASSETS			
Current assets			
Cash and cash equivalents		**$ 565**	$ 744
Accounts receivable		**3,912**	3,111
Inventory		**1,836**	1,548
Prepaids and other		**346**	195
Investments	6	**403**	309
Current portion of other long-term assets	7	**88**	35
		7,150	5,942
Exploration and evaluation assets	3	**2,227**	2,250
Property, plant and equipment	4	**66,172**	66,400
Lease assets	5	**1,444**	1,508
Other long-term assets	7	**486**	565
		$ 77,479	$ 76,665
LIABILITIES			
Current liabilities			
Accounts payable		**$ 1,265**	$ 803
Accrued liabilities		**3,943**	3,064
Current income taxes payable		**1,552**	1,607
Current portion of long-term debt	8	**1,369**	1,000
Current portion of other long-term liabilities	5,9	**996**	948
		9,125	7,422
Long-term debt	8	**11,580**	13,694
Other long-term liabilities	5,9	**7,930**	8,384
Deferred income taxes		**10,705**	10,220
		39,340	39,720
SHAREHOLDERS' EQUITY			
Share capital	11	**10,162**	10,168
Retained earnings		**27,747**	26,778
Accumulated other comprehensive income (loss)	12	**230**	(1)
		38,139	36,945
		$ 77,479	$ 76,665

Commitments and contingencies (note 16)

Approved by the Board of Directors on November 2, 2022.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Sep 30 2022	Three Months Ended Sep 30 2021	Nine Months Ended Sep 30 2022	Nine Months Ended Sep 30 2021
Product sales	17	**$ 12,574**	$ 8,521	**$ 38,518**	$ 22,664
Less: royalties		**(2,117)**	(810)	**(5,909)**	(1,820)
Revenue		**10,457**	7,711	**32,609**	20,844
Expenses					
Production		**2,076**	1,762	**6,403**	5,283
Transportation, blending and feedstock		**2,235**	1,516	**7,372**	4,539
Depletion, depreciation and amortization	4,5	**1,454**	1,442	**4,224**	4,251
Administration		**94**	87	**307**	269
Share-based compensation	9	**(4)**	57	**485**	323
Asset retirement obligation accretion	9	**82**	47	**199**	139
Interest and other financing expense		**150**	178	**473**	540
Risk management activities	15	**(92)**	(23)	**(48)**	34
Foreign exchange loss (gain)		**736**	281	**923**	(21)
Gain on acquisitions		**—**	(478)	**—**	(478)
Income from North West Redwater Partnership	7	**—**	—	**—**	(400)
(Gain) loss from investments	6	**(39)**	33	**(103)**	(136)
		6,692	4,902	**20,235**	14,343
Earnings before taxes		**3,765**	2,809	**12,374**	6,501
Current income tax expense	10	**757**	551	**2,507**	1,165
Deferred income tax expense	10	**194**	56	**450**	206
Net earnings		**$ 2,814**	$ 2,202	**$ 9,417**	$ 5,130
Net earnings per common share					
Basic	14	**$ 2.52**	$ 1.87	**$ 8.23**	$ 4.33
Diluted	14	**$ 2.49**	$ 1.86	**$ 8.12**	$ 4.32

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2022	Three Months Ended Sep 30 2021	Nine Months Ended Sep 30 2022	Nine Months Ended Sep 30 2021
Net earnings	**$ 2,814**	$ 2,202	**$ 9,417**	$ 5,130
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 – $3 million) – nine months ended	**—**	16	**4**	34
Reclassification to net earnings, net of taxes of $nil (2021 – $nil) – three months ended; $1 million (2021 – $1 million) – nine months ended	**(2)**	(3)	**(6)**	(8)
	(2)	13	**(2)**	26
Foreign currency translation adjustment				
Translation of net investment	**185**	70	**233**	3
Other comprehensive income, net of taxes	**183**	83	**231**	29
Comprehensive income	**$ 2,997**	$ 2,285	**$ 9,648**	$ 5,159

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended Sep 30 2022	Sep 30 2021
Share capital	11		
Balance – beginning of period		**$ 10,168**	$ 9,606
Issued upon exercise of stock options		**332**	347
Previously recognized liability on stock options exercised for common shares		**276**	50
Purchase of common shares under Normal Course Issuer Bid		**(614)**	(146)
Balance – end of period		**10,162**	9,857
Retained earnings			
Balance – beginning of period		**26,778**	22,766
Net earnings		**9,417**	5,130
Dividends on common shares	11	**(4,237)**	(1,667)
Purchase of common shares under Normal Course Issuer Bid	11	**(4,211)**	(597)
Balance – end of period		**27,747**	25,632
Accumulated other comprehensive income (loss)	12		
Balance – beginning of period		**(1)**	8
Other comprehensive income, net of taxes		**231**	29
Balance – end of period		**230**	37
Shareholders' equity		**$ 38,139**	$ 35,526

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Sep 30 2022**	Three Months Ended Sep 30 2021	Nine Months Ended **Sep 30 2022**	Nine Months Ended Sep 30 2021
Operating activities					
Net earnings		**$ 2,814**	$ 2,202	**$ 9,417**	$ 5,130
Non-cash items					
Depletion, depreciation and amortization		**1,454**	1,442	**4,224**	4,251
Share-based compensation		**(4)**	57	**485**	323
Asset retirement obligation accretion		**82**	47	**199**	139
Unrealized risk management (gain) loss		**(48)**	(19)	**(43)**	11
Unrealized foreign exchange loss (gain)		**785**	197	**1,055**	(126)
Realized foreign exchange loss (gain) (1)		**—**	118	**(69)**	118
Gain on acquisitions		**—**	(478)	**—**	(478)
(Gain) loss from investments	6	**(36)**	35	**(94)**	(129)
Deferred income tax expense		**194**	56	**450**	206
Proceeds on settlement of cross currency swap	15	**—**	—	**89**	—
Other		**(20)**	19	**(79)**	(8)
Abandonment expenditures		**(147)**	(77)	**(349)**	(215)
Net change in non-cash working capital		**1,024**	691	**(438)**	544
Cash flows from operating activities		**6,098**	4,290	**14,847**	9,766
Financing activities					
Repayment of bank credit facilities and commercial paper, net	8	**—**	(1,184)	**(1,156)**	(4,172)
Repayment of medium-term notes	8	**(341)**	—	**(1,480)**	—
Repayment of US dollar debt securities	8	**—**	(628)	**—**	(628)
Proceeds on settlement of cross currency swap	15	**—**	—	**69**	—
Payment of lease liabilities	5,9	**(50)**	(49)	**(149)**	(154)
Issue of common shares on exercise of stock options	11	**23**	83	**332**	347
Dividends on common shares		**(2,532)**	(558)	**(4,092)**	(1,618)
Purchase of common shares under Normal Course Issuer Bid	11	**(1,737)**	(507)	**(4,825)**	(743)
Cash flows used in financing activities		**(4,637)**	(2,843)	**(11,301)**	(6,968)
Investing activities					
Net expenditures on exploration and evaluation assets	3,17	**(3)**	(4)	**(24)**	(5)
Net expenditures on property, plant and equipment	4,17	**(1,132)**	(953)	**(3,879)**	(2,934)
Proceeds from investment		**—**	128	**—**	128
Repayment of North West Redwater Partnership subordinated debt advances		**—**	—	**—**	555
Net change in non-cash working capital		**6**	108	**178**	168
Cash flows used in investing activities		**(1,129)**	(721)	**(3,725)**	(2,088)
Increase (decrease) in cash and cash equivalents		**332**	726	**(179)**	710
Cash and cash equivalents – beginning of period		**233**	168	**744**	184
Cash and cash equivalents – end of period		**$ 565**	$ 894	**$ 565**	$ 894
Interest paid on long-term debt, net		**$ 179**	$ 196	**$ 482**	$ 550
Income taxes paid (received), net		**$ 312**	$ (11)	**$ 2,482**	$ (94)

(1) Consists of the realized foreign exchange gain on settlement of cross currency swap in 2022 and the realized foreign exchange loss on repayment of US dollar debt securities in 2021.

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	**34**	**—**	**—**	**—**	**34**
Transfers to property, plant and equipment	**(60)**	**—**	**—**	**—**	**(60)**
Foreign exchange adjustments	**—**	**—**	**3**	**—**	**3**
At September 30, 2022	**$ 2,031**	**$ —**	**$ 94**	**$ 102**	**$ 2,227**

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	**2,460**	**78**	**67**	**1,277**	**7**	**18**	**3,907**
Transfers from exploration & evaluation assets	**60**	**—**	**—**	**—**	**—**	**—**	**60**
Change in asset retirement obligation estimates	**144**	**(103)**	**(38)**	**(328)**	**—**	**—**	**(325)**
Derecognitions (1)	**(249)**	**(1)**	**—**	**(326)**	**—**	**—**	**(576)**
Foreign exchange adjustments and other	**—**	**610**	**330**	**—**	**—**	**4**	**944**
At September 30, 2022	**$ 80,249**	**$ 8,022**	**$ 4,339**	**$ 47,479**	**$ 473**	**$ 530**	**$ 141,092**
Accumulated depletion and depreciation							
At December 31, 2021	$ 52,732	$ 5,951	$ 2,923	$ 8,499	$ 183	$ 394	$ 70,682
Expense	**2,576**	**87**	**113**	**1,258**	**11**	**18**	**4,063**
Derecognitions (1)	**(249)**	**(1)**	**—**	**(326)**	**—**	**—**	**(576)**
Foreign exchange adjustments and other	**(8)**	**508**	**249**	**(2)**	**—**	**4**	**751**
At September 30, 2022	**$ 55,051**	**$ 6,545**	**$ 3,285**	**$ 9,429**	**$ 194**	**$ 416**	**$ 74,920**
Net book value							
At September 30, 2022	**$ 25,198**	**$ 1,477**	**$ 1,054**	**$ 38,050**	**$ 279**	**$ 114**	**$ 66,172**
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 nine months ended September 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 $513 million and assumed associated asset retirement obligations of $11 million. No net deferred income tax liabilities were recognized and no pre-tax gains were recognized on these 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**	**27**	**21**	**—**	**92**
Depreciation	**(80)**	**(44)**	**(21)**	**(16)**	**(161)**
Foreign exchange adjustments and other	**—**	**—**	**3**	**2**	**5**
At September 30, 2022	**$ 938**	**$ 337**	**$ 102**	**$ 67**	**$ 1,444**

Lease liabilities

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

	Sep 30 2022	Dec 31 2021
Lease liabilities	**$ 1,530**	$ 1,584
Less: current portion	**193**	185
	$ 1,337	$ 1,399

Total cash outflows for leases for the three months ended September 30, 2022, including payments related to short-term leases not reported as lease assets, were $326 million (three months ended September 30, 2021 – $257 million; nine months ended September 30, 2022 – $882 million; nine months ended September 30, 2021 – $831 million). Interest expense on leases for the three months ended September 30, 2022 was $15 million (three months ended September 30, 2021 – $15 million; nine months ended September 30, 2022 – $45 million; nine months ended September 30, 2021 – $47 million).

6. INVESTMENTS

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

	Sep 30 2022	Dec 31 2021
Investment in PrairieSky Royalty Ltd.	**$ 403**	$ 309

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2022	Sep 30 2021(1)	**Sep 30 2022**	Sep 30 2021(1)
(Gain) loss from investments	**$ (36)**	$ 35	**$ (94)**	$ (129)
Dividend income	**(3)**	(2)	**(9)**	(7)
	$ (39)	$ 33	**$ (103)**	$ (136)

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

The Company's 22.6 million share investment in PrairieSky Royalty Ltd. does not constitute significant influence, and is accounted for at fair value through profit or loss, measured at each reporting date. As at September 30, 2022, the market price per common share was $17.81 (December 31, 2021 – $13.63; September 30, 2021 – $13.51).

7. OTHER LONG-TERM ASSETS

	Sep 30 2022	Dec 31 2021
Prepaid cost of service tolls	**$ 197**	$ 157
Long-term inventory	**136**	126
Risk management (note 15)	**36**	140
Long-term contracts and prepayments [(1)]	**205**	177
	574	600
Less: current portion	**88**	35
	$ 486	$ 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).

During the third quarter of 2022, NWRP extended its $3,000 million syndicated credit facility and increased it to $3,175 million. The revolving portion of the credit facility was increased to $2,175 million, with $118 million maturing in June 2023, and $2,057 million maturing in June 2025. The $1,000 million non-revolving portion of the credit facility was extended, with $60 million maturing in June 2023, and $940 million maturing in June 2025. During the third quarter of 2022, NWRP also entered into a $150 million facility to support letters of credit.

The carrying value of the Company's interest in NWRP is $nil, and as at September 30, 2022, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $588 million (December 31, 2021 – $562 million). For the three months ended September 30, 2022, the Company's unrecognized share of the equity loss was $1 million (nine months ended September 30, 2022 – unrecognized equity loss of $26 million; three months ended September 30, 2021 – unrecognized equity loss of $21 million; nine months ended September 30, 2021 – recovery of unrecognized equity losses of $3 million and partnership distributions of $400 million).

8. LONG-TERM DEBT

	Sep 30 2022	Dec 31 2021
Canadian dollar denominated debt, unsecured		
Medium-term notes	**$ 1,720**	$ 3,200
US dollar denominated debt, unsecured		
Bank credit facilities (September 30, 2022 – US$nil; December 31, 2021 – US$901 million)	**—**	1,140
US dollar debt securities (September 30, 2022 – US$8,250 million; December 31, 2021 – US$8,250 million)	**11,302**	10,441
	11,302	11,581
Long-term debt before transaction costs and original issue discounts, net	**13,022**	14,781
Less: original issue discounts, net [(1)]	**13**	15
transaction costs [(1) (2)]	**60**	72
	12,949	14,694
Less: current portion of other long-term debt [(1) (2)]	**1,369**	1,000
	$ 11,580	$ 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 September 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 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. Subsequent to September 30, 2022, the $500 million revolving credit facility was extended to February 2024.

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 nine months ended September 30, 2022 was 4.2% (September 30, 2021 – 3.4%).

As at September 30, 2022, letters of credit and guarantees aggregating to $571 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 third quarter of 2022, the Company repaid through market purchases $341 million of medium-term notes with interest rates ranging from 1.45% to 3.55%, originally due between 2023 and 2028 (nine months ended September 30, 2022 - $480 million). Subsequent to September 30, 2022, the Company repaid through market purchases an additional $5 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

	Sep 30 2022	Dec 31 2021
Asset retirement obligations	**$ 6,428**	$ 6,806
Lease liabilities (note 5)	**1,530**	1,584
Share-based compensation	**628**	489
Transportation and processing contracts	**178**	241
Risk management (note 15)	**21**	85
Other (1)	**141**	127
	8,926	9,332
Less: current portion	**996**	948
	$ 7,930	$ 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:

	Sep 30 2022	Dec 31 2021
Balance – beginning of period	**$ 6,806**	$ 5,861
Liabilities incurred	**17**	5
Liabilities acquired, net	**11**	76
Liabilities settled	**(349)**	(307)
Asset retirement obligation accretion	**199**	185
Revision of cost estimates	**519**	508
Revision of timing estimates (1)	**854**	1,208
Change in discount rates	**(1,698)**	(723)
Foreign exchange adjustments	**69**	(7)
Balance – end of period	**6,428**	6,806
Less: current portion	**272**	249
	$ 6,156	$ 6,557

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

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.

	Sep 30 2022	Dec 31 2021
Balance – beginning of period	**$ 489**	$ 160
Share-based compensation expense	**485**	514
Cash payment for stock options surrendered and PSUs vested	**(75)**	(48)
Transferred to common shares	**(276)**	(139)
Other	**5**	2
Balance – end of period	**628**	489
Less: current portion	**409**	329
	$ 219	$ 160

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Nine Months Ended	
Expense (recovery)	**Sep 30 2022**	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Current corporate income tax – North America	**$ 755**	$ 541	**$ 2,444**	$ 1,150
Current corporate income tax – North Sea	**14**	4	**36**	10
Current corporate income tax – Offshore Africa	**21**	7	**51**	18
Current PRT (1) – North Sea	**(36)**	(5)	**(37)**	(22)
Other taxes	**3**	4	**13**	9
Current income tax	**757**	551	**2,507**	1,165
Deferred income tax	**194**	56	**450**	206
Income tax	**$ 951**	$ 607	**$ 2,957**	$ 1,371

(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	Nine Months Ended Sep 30, 2022 Number of shares (thousands)	Amount
Balance – beginning of period	**1,168,369**	**$ 10,168**
Issued upon exercise of stock options	**8,816**	**332**
Previously recognized liability on stock options exercised for common shares	**—**	**276**
Purchase of common shares under Normal Course Issuer Bid	**(67,738)**	**(614)**
Balance – end of period	**1,109,447**	**$ 10,162**

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 November 2, 2022, the Board of Directors approved a 13% increase in the quarterly dividend to $0.85 per common share, beginning with the dividend payable on January 5, 2023.

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

On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share. 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.

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 nine months ended September 30, 2022, the Company purchased 67,738,200 common shares at a weighted average price of $71.23 per common share for a total cost of $4,825 million. Retained earnings were reduced by $4,211 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2022, the Company purchased 3,450,000 common shares at a weighted average price of $76.64 per common share for a total cost of $264 million.

Share-Based Compensation – Stock Options

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

	Nine Months Ended Sep 30, 2022	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**38,327**	**$ 35.88**
Granted	**7,121**	**$ 67.46**
Exercised for common shares	**(8,816)**	**$ 37.70**
Surrendered for cash settlement	**(346)**	**$ 38.12**
Forfeited	**(2,354)**	**$ 41.02**
Outstanding – end of period	**33,932**	**$ 41.66**
Exercisable – end of period	**4,718**	**$ 36.81**

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

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Sep 30 2022	Sep 30 2021
Derivative financial instruments designated as cash flow hedges	**$ 75**	$ 95
Foreign currency translation adjustment	**155**	(58)
	$ 230	$ 37

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 September 30, 2022, the ratio was slightly below the target range at 24.5%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

	Sep 30 2022	Dec 31 2021
Long-term debt	**$ 12,949**	$ 14,694
Less: cash and cash equivalents	**565**	744
Long-term debt, net	**$ 12,384**	$ 13,950
Total shareholders' equity	**$ 38,139**	$ 36,945
Debt to book capitalization	**24.5%**	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 September 30, 2022, the Company was in compliance with this covenant.

14. NET EARNINGS PER COMMON SHARE

		Three Months Ended		Nine Months Ended	
		Sep 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Weighted average common shares outstanding – basic (thousands of shares)		**1,118,717**	1,179,603	**1,144,705**	1,183,463
Effect of dilutive stock options (thousands of shares)		**12,712**	5,356	**14,530**	3,689
Weighted average common shares outstanding – diluted (thousands of shares)		**1,131,429**	1,184,959	**1,159,235**	1,187,152
Net earnings		**$ 2,814**	$ 2,202	**$ 9,417**	$ 5,130
Net earnings per common share	– basic	**$ 2.52**	$ 1.87	**$ 8.23**	$ 4.33
	– diluted	**$ 2.49**	$ 1.86	**$ 8.12**	$ 4.32

15. FINANCIAL INSTRUMENTS

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

	Sep 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	**$ 565**	**$ —**	**$ —**	**$ —**	**$ 565**
Accounts receivable	**3,912**	**—**	**—**	**—**	**3,912**
Investments	**—**	**403**	**—**	**—**	**403**
Other long-term assets	**—**	**36**	**—**	**—**	**36**
Accounts payable	**—**	**—**	**—**	**(1,265)**	**(1,265)**
Accrued liabilities	**—**	**—**	**—**	**(3,943)**	**(3,943)**
Other long-term liabilities (1)	**—**	**(21)**	**—**	**(1,555)**	**(1,576)**
Long-term debt (2)	**—**	**—**	**—**	**(12,949)**	**(12,949)**
	$ 4,477	**$ 418**	**$ —**	**$ (19,712)**	**$ (14,817)**

	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 $1,530 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:

	Sep 30, 2022			
	Carrying amount	**Fair value**		
Asset (liability) [1] [2]		**Level 1**	**Level 2**	**Level 3** [4]
Investments [3]	**$ 403**	**$ 403**	**$ —**	**$ —**
Other long-term assets	**$ 36**	**$ —**	**$ 36**	**$ —**
Other long-term liabilities	**$ (46)**	**$ —**	**$ (21)**	**$ (25)**
Fixed rate long-term debt [5] [6]	**$ (12,949)**	**$ (12,299)**	**$ —**	**$ —**

	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)	**Sep 30 2022**	Dec 31 2021
Derivatives held for trading		
Natural gas [1]	**$ 16**	$ (41)
Crude oil and NGLs [1]	**(2)**	(10)
Foreign currency forward contracts	**1**	(13)
Cash flow hedges		
Foreign currency forward contracts	**—**	(21)
Cross currency swaps	**—**	140
	$ 15	$ 55
Included within:		
Current portion of other long-term assets	**$ 27**	$ 5
Current portion of other long-term liabilities	**(21)**	(72)
Other long-term assets	**9**	135
Other long-term liabilities	**—**	(13)
	$ 15	$ 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)	**Sep 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	**79**	(12)
Foreign exchange	**(119)**	82
Other comprehensive income	**—**	9
Balance – end of period	**15**	55
Less: current portion	**6**	(67)
	$ 9	$ 122

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2022	Sep 30 2021	**Sep 30 2022**	Sep 30 2021
Net realized risk management (gain) loss	**$ (44)**	$ (4)	**$ (5)**	$ 23
Net unrealized risk management (gain) loss	**(48)**	(19)	**(43)**	11
	$ (92)	$ (23)	**$ (48)**	$ 34

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 September 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 September 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 September 30, 2022, the Company had US$597 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 September 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 September 30, 2022, the Company had net risk management assets of $24 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 September 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	$ 1,265	$ —	$ —	$ —
Accrued liabilities	$ 3,943	$ —	$ —	$ —
Long-term debt (1)	$ 1,370	$ 1,439	$ 3,797	$ 6,416
Other long-term liabilities (2)	$ 239	$ 159	$ 426	$ 752
Interest and other financing expense (3)	$ 623	$ 592	$ 1,472	$ 3,886

(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, $193 million; one to less than two years, $159 million; two to less than five years, $426 million; and thereafter, $752 million.

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

	Remaining 2022	2023	2024	2025	2026	Thereafter
Product transportation and processing (1)	$ 284	$ 1,119	$ 1,194	$ 1,070	$ 1,008	$ 12,013
North West Redwater Partnership service toll (2)	$ 36	$ 144	$ 145	$ 143	$ 124	$ 4,678
Offshore vessels and equipment	$ 41	$ 42	$ —	$ —	$ —	$ —
Field equipment and power	$ 17	$ 21	$ 21	$ 21	$ 21	$ 226
Other	$ 8	$ 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 $2,534 million of interest payable over the 40-year tolling period, ending in 2058 (note 7).

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

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

17. SEGMENTED INFORMATION

	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
(millions of Canadian dollars, unaudited)	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Segmented product sales																
Crude oil and NGLs	**4,622**	3,506	**16,631**	10,047	**48**	141	**395**	410	**143**	163	**541**	381	**4,813**	3,810	**17,567**	10,838
Natural gas	**1,266**	644	**3,697**	1,583	**3**	1	**9**	3	**18**	5	**47**	20	**1,287**	650	**3,753**	1,606
Other income and revenue [1]	**59**	28	**198**	81	**—**	—	**3**	—	**2**	3	**6**	6	**61**	31	**207**	87
Total segmented product sales	**5,947**	4,178	**20,526**	11,711	**51**	142	**407**	413	**163**	171	**594**	407	**6,161**	4,491	**21,527**	12,531
Less: royalties	**(977)**	(448)	**(3,193)**	(1,128)	**—**	—	**(1)**	(1)	**(20)**	(8)	**(50)**	(18)	**(997)**	(456)	**(3,244)**	(1,147)
Segmented revenue	**4,970**	3,730	**17,333**	10,583	**51**	142	**406**	412	**143**	163	**544**	389	**5,164**	4,035	**18,283**	11,384
Segmented expenses																
Production	**911**	728	**2,771**	2,169	**46**	85	**241**	253	**25**	30	**78**	77	**982**	843	**3,090**	2,499
Transportation, blending and feedstock	**1,290**	1,023	**4,889**	3,313	**1**	1	**5**	5	**1**	1	**1**	1	**1,292**	1,025	**4,895**	3,319
Depletion, depreciation and amortization	**913**	881	**2,646**	2,630	**15**	40	**94**	127	**39**	48	**132**	123	**967**	969	**2,872**	2,880
Asset retirement obligation accretion	**50**	26	**120**	76	**10**	6	**23**	16	**2**	1	**5**	4	**62**	33	**148**	96
Risk management activities (commodity derivatives)	**(49)**	(4)	**6**	32	**—**	—	**—**	—	**—**	—	**—**	—	**(49)**	(4)	**6**	32
Gain on acquisitions	**—**	(478)	**—**	(478)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(478)	**—**	(478)
Income from North West Redwater Partnership	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**3,115**	2,176	**10,432**	7,742	**72**	132	**363**	401	**67**	80	**216**	205	**3,254**	2,388	**11,011**	8,348
Segmented earnings (loss)	**1,855**	1,554	**6,901**	2,841	**(21)**	10	**43**	11	**76**	83	**328**	184	**1,910**	1,647	**7,272**	3,036
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange loss (gain)																
(Gain) loss from investments																
Total non–segmented expenses																
Earnings before taxes																
Current income tax																
Deferred income tax																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream and Refining				Inter–segment elimination and other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2022	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Segmented product sales																
Crude oil and NGLs (2)	**6,056**	3,848	**15,869**	9,625	**21**	21	**59**	61	**111**	(72)	**6**	(247)	**11,001**	7,607	**33,501**	20,277
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**55**	44	**196**	152	**1,342**	694	**3,949**	1,758
Other income and revenue (1)	**36**	15	**151**	55	**134**	179	**701**	481	**—**	(5)	**9**	6	**231**	220	**1,068**	629
Total segmented product sales	**6,092**	3,863	**16,020**	9,680	**155**	200	**760**	542	**166**	(33)	**211**	(89)	**12,574**	8,521	**38,518**	22,664
Less: royalties	**(1,120)**	(354)	**(2,665)**	(673)	**—**	—	**—**	—	**—**	—	**—**	—	**(2,117)**	(810)	**(5,909)**	(1,820)
Segmented revenue	**4,972**	3,509	**13,355**	9,007	**155**	200	**760**	542	**166**	(33)	**211**	(89)	**10,457**	7,711	**32,609**	20,844
Segmented expenses																
Production	**1,005**	855	**3,059**	2,543	**72**	50	**208**	192	**17**	14	**46**	49	**2,076**	1,762	**6,403**	5,283
Transportation, blending and feedstock (2)	**684**	387	**1,785**	978	**113**	146	**536**	385	**146**	(42)	**156**	(143)	**2,235**	1,516	**7,372**	4,539
Depletion, depreciation and amortization	**484**	469	**1,341**	1,360	**3**	4	**11**	11	**—**	—	**—**	—	**1,454**	1,442	**4,224**	4,251
Asset retirement obligation accretion	**20**	14	**51**	43	**—**	—	**—**	—	**—**	—	**—**	—	**82**	47	**199**	139
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(49)**	(4)	**6**	32
Gain on acquisitions	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(478)	**—**	(478)
Income from North West Redwater Partnership	**—**	—	**—**	—	**—**	—	**—**	(400)	**—**	—	**—**	—	**—**	—	**—**	(400)
Total segmented expenses	**2,193**	1,725	**6,236**	4,924	**188**	200	**755**	188	**163**	(28)	**202**	(94)	**5,798**	4,285	**18,204**	13,366
Segmented earnings (loss)	**2,779**	1,784	**7,119**	4,083	**(33)**	—	**5**	354	**3**	(5)	**9**	5	**4,659**	3,426	**14,405**	7,478
Non–segmented expenses																
Administration													**94**	87	**307**	269
Share-based compensation													**(4)**	57	**485**	323
Interest and other financing expense													**150**	178	**473**	540
Risk management activities (other)													**(43)**	(19)	**(54)**	2
Foreign exchange loss (gain)													**736**	281	**923**	(21)
(Gain) loss from investments													**(39)**	33	**(103)**	(136)
Total non-segmented expenses													**894**	617	**2,031**	977
Earnings before taxes													**3,765**	2,809	**12,374**	6,501
Current income tax													**757**	551	**2,507**	1,165
Deferred income tax													**194**	56	**450**	206
Net earnings													**2,814**	2,202	**9,417**	5,130

(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]

	Nine Months Ended					
	Sep 30, 2022			Sep 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	**$ 24**	**$ (50)**	**$ (26)**	$ (1)	$ (43)	$ (44)
Offshore Africa	**—**	**—**	**—**	6	—	6
	24	**(50)**	**(26)**	5	(43)	(38)
Property, plant and equipment						
Exploration and Production						
North America	**2,432**	**(17)**	**2,415**	1,362	(96)	1,266
North Sea	**78**	**(104)**	**(26)**	125	(6)	119
Offshore Africa	**67**	**(38)**	**29**	37	2	39
	2,577	**(159)**	**2,418**	1,524	(100)	1,424
Oil Sands Mining and Upgrading [3]	**1,277**	**(654)**	**623**	1,388	(322)	1,066
Midstream and Refining	**7**	**—**	**7**	6	—	6
Head office	**18**	**—**	**18**	16	—	16
	3,879	**(813)**	**3,066**	2,934	(422)	2,512
	$ 3,903	**$ (863)**	**$ 3,040**	$ 2,939	$ (465)	$ 2,474

(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

	Sep 30 2022	Dec 31 2021
Exploration and Production		
North America	**$ 30,942**	$ 30,645
North Sea	**1,622**	1,561
Offshore Africa	**1,335**	1,332
Other	**118**	40
Oil Sands Mining and Upgrading	**42,421**	42,016
Midstream and Refining	**867**	886
Head office	**174**	185
	$ 77,479	$ 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 September 30, 2022:	
Interest coverage (times)	
Net earnings [(1)]	25.5x
Adjusted funds flow [(2)]	36.9x

(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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