THIRD QUARTER REPORT

NINE MONTHS ENDED SEPTEMBER 30, 2021 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2021 THIRD QUARTER RESULTS

Commenting on the Company's third quarter 2021 results, Tim McKay, President of Canadian Natural stated "Our diverse product mix is a competitive advantage, as we can allocate capital to the highest return projects, without being reliant on any one commodity. Our effective and efficient operations combined with disciplined capital allocation generates significant free cash flow, which delivers substantial shareholder returns through our sustainable dividend and ongoing share repurchases. Our world class long life low decline assets, which have low maintenance capital requirements relative to the size and quality of the assets, delivered top tier Q3/21 operational and financial results with average production volumes of approximately 1,238 MBOE/d achieved in the quarter, representing increases of 11% and 8% over Q3/20 and Q2/21 levels respectively. Our strong operational results during Q3/21 delivered robust quarterly adjusted funds flow of approximately $3.6 billion. After our disciplined capital program and dividend, the Company generated quarterly free cash flow of approximately $2.2 billion.

Environmental, Social and Governance ("ESG") performance remains a priority. We continue to invest in technologies and innovations designed to improve our environmental performance and reduce our environmental footprint. As previously announced, the Oil Sands Pathways initiative to achieve net zero greenhouse gas emissions by 2050 is an unprecedented initiative by the Canadian energy industry. Canadian Natural and Pathways alliance members are developing several technology pathways that when implemented will strengthen our leading ESG performance through meaningful emissions reductions while maintaining jobs in the oil sands sector and creating thousands of new construction and permanent jobs in the energy and cleantech industries. Collaboration with the federal and Alberta governments on this initiative will be critical for Canada to achieve its climate goals."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "During the third quarter of 2021 our robust business model delivered strong net earnings of over $2.2 billion and adjusted net earnings of approximately $2.1 billion. Our diversified portfolio of world class assets combined with effective and efficient operations in a strong commodity price environment, allowed us to continue to enhance returns to shareholders by repurchasing shares and reducing debt at a faster rate than originally targeted. The Company's balance sheet continues to be a priority and was further strengthened during the quarter with ending net debt at approximately $15.9 billion, a reduction of approximately $2.3 billion compared to Q2/21. We remain on track to meet our full year 2021 capital investment target of approximately $3.48 billion.

Our commitment to returns to shareholders has been significant totaling $3.1 billion year to date through dividends and share repurchases. Subsequent to quarter end the Board of Directors has approved a 25% increase to our quarterly dividend to $0.5875 per share, payable on January 5, 2022. The increased dividend clearly demonstrates the confidence that the Board of Directors have in the sustainability of our business model, the strength of our balance sheet and the Company’s effective and efficient operations supported by our robust, long life low decline asset base and associated low maintenance capital requirements. With this increase, 2022 will mark the 22nd consecutive year of dividend increases for the Company, and this 25% increase from our previous quarterly dividend is in excess of our historical dividend compound annual growth rate of 20% over the last 22 years.

Effective July 1, 2021 our free cash flow allocation policy authorized management to increase returns to shareholders through accelerated share repurchases under the Company's Normal Course Issuer Bid (“NCIB”) by targeting the repurchase of approximately 1% of shares outstanding per quarter. This policy further states that once the Company reaches an absolute debt level of $15 billion, currently targeted to occur in Q4/21, 50% of free cash flow will be targeted to share repurchases, with the remaining 50% of free cash flow allocated to further strengthen our balance sheet. Per this policy, the Company repurchased approximately 12 million shares in the quarter and year-to-date as of November 3, 2021 we have repurchased a total of approximately 21.5 million shares for approximately $940 million. Subsequent to quarter end, and as an enhancement to the free cash flow allocation policy, the Board of Directors has authorized management to target absolute debt at levels below $15 billion (approximately 1.0 times debt to EBITDA in the current price environment). To the extent debt is below $15 billion, such amount will be available for strategic growth/acquisition opportunities."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Sep 30 2021**	Three Months Ended Jun 30 2021	Three Months Ended Sep 30 2020	Nine Months Ended **Sep 30 2021**	Nine Months Ended Sep 30 2020
Net earnings (loss)	**$ 2,202**	$ 1,551	$ 408	**$ 5,130**	$ (1,184)
Per common share – basic	**$ 1.87**	$ 1.31	$ 0.35	**$ 4.33**	$ (1.00)
– diluted	**$ 1.86**	$ 1.30	$ 0.35	**$ 4.32**	$ (1.00)
Adjusted net earnings (loss) from operations (1)	**$ 2,095**	$ 1,480	$ 135	**$ 4,794**	$ (932)
Per common share – basic	**$ 1.78**	$ 1.25	$ 0.11	**$ 4.05**	$ (0.79)
– diluted	**$ 1.77**	$ 1.24	$ 0.11	**$ 4.04**	$ (0.79)
Cash flows from operating activities	**$ 4,290**	$ 2,940	$ 2,070	**$ 9,766**	$ 3,444
Adjusted funds flow (2)	**$ 3,634**	$ 3,049	$ 1,740	**$ 9,395**	$ 3,492
Per common share – basic	**$ 3.08**	$ 2.57	$ 1.47	**$ 7.94**	$ 2.96
– diluted	**$ 3.07**	$ 2.56	$ 1.47	**$ 7.91**	$ 2.96
Cash flows used in investing activities	**$ 721**	$ 719	$ 643	**$ 2,088**	$ 2,195
Net capital expenditures, excluding net acquisition costs (3)	**$ 881**	$ 957	$ 771	**$ 2,646**	$ 2,030
Net capital expenditures, including net acquisition costs (3)	**$ 1,011**	$ 1,285	$ 771	**$ 3,104**	$ 2,030
Daily production, before royalties					
Natural gas (MMcf/d)	**1,708**	1,614	1,362	**1,640**	1,421
Crude oil and NGLs (bbl/d)	**952,839**	872,718	884,342	**934,873**	914,859
Equivalent production (BOE/d) (4)	**1,237,503**	1,141,739	1,111,286	**1,208,285**	1,151,693

Footnotes 1 through 3 describe non-GAAP financial measures that the Company considers key in evaluating its performance. Derivations of these measures are discussed in the "Advisory" section of this press release.

(1) Adjusted net earnings (loss) from operations demonstrates the Company's ability to generate after-tax operating earnings from its core business areas.

(2) Adjusted funds flow demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt.

(3) Net capital expenditures provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget.

(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.

- Net earnings of $2,202 million and adjusted net earnings from operations of $2,095 million were realized in Q3/21, significant increases from Q2/21 net earnings of $1,551 million and adjusted net earnings from operations of $1,480 million, primarily as a result of higher realized pricing and effective and efficient operations.
- Cash flows from operating activities were $4,290 million in Q3/21, increases from $2,070 million in Q3/20 and $2,940 million in Q2/21.
- The strength of our balanced asset base, supported by safe, effective and efficient operations generates significant free cash flow over the long-term, making Canadian Natural's business unique, robust and sustainable.
  - Canadian Natural has a diverse asset base underpinned by low maintenance capital requirements and effective and efficient operations that delivers significant free cash flow.
  - Canadian Natural generated strong quarterly adjusted funds flow of $3,634 million in Q3/21, a significant increase from Q2/21 levels of $3,049 million, primarily the result of higher realized pricing and effective and efficient operations.
  - Reflecting the strength of our effective and efficient operations and our high quality, long life low decline asset base, Canadian Natural generated strong quarterly free cash flow of $2,195 million in Q3/21, after dividend payments of $558 million and net capital expenditures of $881 million, excluding acquisitions.
- Returns to shareholders year to date in 2021 have been significant, as Canadian Natural has returned approximately $3.1 billion by way of dividends and share repurchases up to and including November 3, 2021.

- Share repurchases for cancellation during Q3/21 per the free cash flow allocation policy, totaled 11,984,400 shares or 1% of common shares outstanding at a weighted average price of $42.26 per share. Share repurchases for cancellation in 2021 up to and including November 3, 2021 total 21,464,400 common shares at a weighted average price of $43.77 per share.
- Subsequent to quarter end the Board of Directors has approved a 25% increase to our quarterly dividend to $0.5875 per share, payable on January 5, 2022. The increased dividend clearly demonstrates the confidence that the Board of Directors have in the sustainability of our business model, the strength of our balance sheet and the Company's effective and efficient operations supported by our robust, long life low decline asset base and associated low maintenance capital requirements.
  - With this increase, 2022 will mark the 22nd consecutive year of dividend increases for the Company, and this 25% increase from our previous quarterly dividend is in excess of our historical dividend compound annual growth rate of 20% over the last 22 years.

▪ Canadian Natural executed on our commitment to further strengthen our balance sheet with strong financial results in Q3/21, reducing net debt by approximately $2.3 billion from Q2/21 levels, while net debt has decreased by approximately $5.8 billion over the last 12 months ended September 30, 2021. In Q3/21 the Company executed on the following:

- On August 16, 2021 the Company repaid the US$500 million 3.45% notes originally due November 15, 2021.
- The Company repaid $500 million on its $2,650 million term credit facility due February 2023.
  - Subsequent to quarter end the Company repaid an additional $1,000 million, which reduced the facility balance to $1,150 million as at November 3, 2021.

▪ Effective July 1, 2021 our free cash flow allocation policy authorized management to increase returns to shareholders through accelerated share repurchases under the Company's NCIB by targeting the repurchase of approximately 1% of shares outstanding per quarter. This policy further states that once the Company reaches an absolute debt level of $15 billion, currently targeted to occur in Q4/21, 50% of free cash flow will be targeted to share repurchases, with the remaining 50% of free cash flow allocated to further strengthen our balance sheet. Per this policy, the Company repurchased approximately 12 million shares in the quarter and year to date as of November 3, 2021 we have repurchased a total of approximately 21.5 million shares for approximately $940 million. Subsequent to quarter end, and as an enhancement to the free cash flow allocation policy, the Board of Directors has authorized management to target absolute debt at levels below $15 billion (approximately 1.0 times debt to EBITDA in the current price environment). To the extent debt is below $15 billion, such amount will be available for strategic growth/acquisition opportunities.

▪ In Q3/21 the Company continued its focus on safe, effective and efficient operations averaging quarterly production volumes of 1,237,503 BOE/d, increases of 11% and 8% from Q3/20 and Q2/21 levels respectively. The increases from prior periods are primarily as a result of robust natural gas production and strong Oil Sands Mining and Upgrading performance after completion of planned turnaround activities.

- The Company delivered strong natural gas performance in Q3/21 with corporate natural gas production of 1,708 MMcf/d, an increase of 6% from Q2/21 levels. The increase from Q2/21 levels primarily reflects reinstated production volumes from the Pine River Gas Plant, acquisitions, and strong drilling results, partially offset by natural field declines.
  - Corporate natural gas operating costs in Q3/21 averaged $1.17/Mcf, a decrease of 2% from Q2/21 levels.
- Strong quarterly liquids production volumes averaged 952,839 bbl/d in Q3/21, increases of 8% and 9% from Q3/20 and Q2/21 levels respectively, primarily due to Canadian Natural's effective and efficient operations and planned turnaround activities completed in prior periods.

▪ Canadian Natural's North America E&P liquids production, including thermal in situ, averaged 454,888 bbl/d during Q3/21, decreases of 8% and 5% from Q3/20 and Q2/21 levels respectively. The decreases from Q3/20 and Q2/21 levels were primarily due to natural field declines, planned turnaround activities at Jackfish and lower NGL production volumes largely due to third-party outages in the quarter.

- North American E&P liquids, including thermal in situ, operating costs averaged $13.33/bbl (US$10.58/bbl) in Q3/21, an increase of 4% from Q2/21 levels. The increase in operating costs from Q2/21 was primarily due to increased energy costs and lower production volumes.

- Canadian Natural's thermal in situ production averaged 248,113 bbl/d in Q3/21, decreases of 14% and 4% from Q3/20 and Q2/21 levels respectively. The decrease in thermal in situ production during Q3/21 compared to Q3/20 and Q2/21 was primarily due to planned turnaround activities at Jackfish and natural field declines.
  - Thermal in situ assets operating costs averaged $12.24/bbl (US$9.71/bbl) in Q3/21, an increase of 4% from Q2/21 levels. The increase in operating costs from Q2/21 was primarily due to increased energy costs and lower production volumes due to planned turnaround activities.
- The Company's world class Oil Sands Mining and Upgrading assets averaged quarterly production of 468,126 bbl/d of Synthetic Crude Oil ("SCO") in Q3/21, increases of 34% and 29% from Q3/20 and Q2/21 levels respectively and comparable to the record average quarterly production volumes achieved in Q1/21. Strong Q3/21 production performance was due to the Company's focus on continuous improvement, effective and efficient operations as well as planned turnaround activities completed during prior periods.
  - Following recently completed maintenance and turnaround activities across the Oil Sands Mining and Upgrading assets, top tier performance and utilization resulted in industry leading operating costs. During the first nine months of 2021, as a result of the successful completion of the Scotford turnaround and expansion in 2020, the Company increased sales volumes by over 20,000 bbl/d of SCO.
  - Operating costs from the Company's Oil Sands Mining and Upgrading assets were strong and remain top tier averaging $19.86/bbl (US$15.76/bbl) of SCO during Q3/21, a decrease of 22% from Q2/21 levels. The decrease from Q2/21 was primarily due to strong production volumes, the Company's culture of continuous improvement and planned turnaround activities completed during the prior period.
  - Oil Sands Mining and Upgrading continue to be top tier with production volumes for October 2021 of approximately 477,000 bbl/d of SCO.

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 81% of our total liquids production in Q3/21, the majority of which is zero decline high value SCO production from the Company's world class Oil Sands Mining and Upgrading assets. The remaining balance of long life low decline production comes from Canadian Natural's top tier thermal in situ oil sands operations and the Company's Pelican Lake heavy crude oil assets. The combination of these long life low decline assets, low reserves replacement costs, and effective and efficient operations, results in substantial and sustainable adjusted funds flow throughout the commodity price cycle.

In addition, Canadian Natural maintains a substantial inventory of low capital exposure projects within the Company's conventional asset base. These projects can be executed quickly and, in the right economic conditions, provide excellent returns and maximize value for our shareholders. Supporting these projects is the Company's undeveloped land base which enables large, repeatable drilling programs that can be optimized over time. Additionally, by owning and operating most of the related infrastructure, Canadian Natural is able to control major components of the Company's operating costs and minimize production commitments. Low capital exposure projects can be quickly stopped or started depending upon success, market conditions or corporate needs.

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

Drilling Activity	Nine Months Ended Sep 30			
	2021		2020	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**130**	**127**	43	37
Natural gas	**50**	**40**	25	21
Dry	**1**	**1**	—	—
Subtotal	**181**	**168**	68	58
Stratigraphic test / service wells	**405**	**336**	426	372
Total	**586**	**504**	494	430
Success rate (excluding stratigraphic test / service wells)		**99%**		100%

- The Company's total crude oil and natural gas drilling program of 168 net wells for the nine months ended September 30, 2021, excluding stratigraphic/service wells, represents an increase of 110 net wells from the same period in 2020, consistent with the 2021 capital budget.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Crude oil and NGLs production (bbl/d)	**206,775**	219,763	206,974	**212,565**	212,064
Net wells targeting crude oil	**55**	22	—	**116**	30
Net successful wells drilled	**54**	22	—	**115**	30
Success rate	**98%**	100%	—%	**99%**	100%

- Canadian Natural's North America E&P crude oil and NGL production volumes, excluding thermal in situ averaged 206,775 bbl/d in Q3/21, comparable with Q3/20 levels. Production volumes decreased by 6% from Q2/21 levels primarily due to lower NGL production volumes largely as a result of third-party outages and natural field declines.
  - Primary heavy crude oil production averaged 63,891 bbl/d in Q3/21, decreases of 10% and 3% from Q3/20 and Q2/21 levels respectively, primarily due to natural field declines, partially offset by strong drilling results and increased development activity in 2021.
    - Operating costs in the Company's primary heavy crude oil operations averaged $19.51/bbl (US$15.48/bbl) in Q3/21, comparable to Q2/21 levels.
    - At the Company's Clearwater play at Smith, the 6 net horizontal multilateral wells brought onstream in the first half of 2021 continue to perform well, with current production rates totaling over 1,800 bbl/d.
      - The additional 6 net horizontal multilateral wells that were targeted to be onstream in Q4/21 are now on production with current volumes totaling approximately 2,100 bbl/d, exceeding the targeted rate of 2,000 bbl/d.
  - Pelican Lake production in Q3/21 averaged 53,923 bbl/d, decreases of 4% and 2% from Q3/20 and Q2/21 levels respectively. The production decreases reflect the low decline nature of this long life low decline asset and the continued success of the Company's world class polymer flood.
    - The Company continues to focus on safe, effective and efficient operations, realizing low operating costs in Q3/21 at Pelican Lake, averaging $5.90/bbl (US$4.68/bbl), a decrease of 14% from Q2/21 levels. The operating cost decrease from Q2/21 levels was primarily due to Canadian Natural's culture of continuous improvement.
  - North America light crude oil and NGL production averaged 88,961 bbl/d in Q3/21, an increase of 12% from Q3/20 levels and a decrease of 10% from Q2/21 levels. The increase from Q3/20 was primarily due to strong drilling results, acquired production over the past 12 months and development activities. The decrease from Q2/21 was primarily due to lower NGL production volumes, which impacted the quarter by approximately 8,400 bbl/d and natural field declines, offset by strong light crude oil drilling results.
    - Operating costs in the Company's North America light crude oil and NGL areas averaged $16.19/bbl (US$12.85/bbl) in Q3/21, an increase of 13% from Q2/21 levels. The increase in Q3/21 was primarily the result of increased energy costs and decreased NGL production volumes.
    - The Company continues to advance its high-value Montney light crude oil development plan at Wembley.
      - 13 net wells were onstream in Q3/21 with 5 additional net wells targeted to be onstream in Q4/21.
      - Construction of a new crude oil battery was completed ahead of schedule and below budgeted costs.
      - The project now targets to exit 2021 with total production rates of more than 10,000 bbl/d of liquids and 30 MMcf/d of natural gas, representing an increase of over 1,500 bbl/d of liquids and approximately 2 MMcf/d of natural gas.
      - The Company is targeting strong well capital efficiencies of approximately $6,800/BOE/d.

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Bitumen production (bbl/d)	**248,113**	258,551	287,978	**257,993**	243,193
Net wells targeting bitumen	**—**	4	—	**7**	6
Net successful wells drilled	**—**	4	—	**7**	6
Success rate	**—%**	100%	—%	**100%**	100%

- Canadian Natural's thermal in situ production averaged 248,113 bbl/d in Q3/21, decreases of 14% and 4% from Q3/20 and Q2/21 levels respectively. Changes in thermal in situ production during Q3/21 compared to Q3/20 and Q2/21 were primarily due to planned turnaround activities at Jackfish and natural field declines.

- Thermal in situ assets operating costs averaged $12.24/bbl (US$9.71/bbl) in Q3/21, an increase of 4% from Q2/21 levels. The increase in operating costs from Q2/21 was primarily due to increased energy costs and lower production volumes due to planned turnaround activities.

▪ Solvent enhanced oil recovery technology is being piloted by the Company with an objective to increase bitumen production, reduce the Steam to Oil Ratio ("SOR"), reduce greenhouse gas ("GHG") intensity and have high solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.

- Results at Kirby South from our on-going two year pilot of this technology were positive, showing SOR and GHG intensity reductions of 45% through the piloted process, consistent with the targeted range, as well as solvent recoveries of approximately 85%, confirming the viability of this technology. As a result, the Company is progressing with engineering and design of a commercial scale SAGD pad development at Kirby North.
- As previously announced, a second solvent injection pilot intended to further validate this technology commenced in October 2021, in the steam flood area of Primrose. The Company's second pilot consists of 9 net wells, 5 producers and 4 injectors. The second pilot targets to operate for a two year period with targeted SOR and GHG intensity reductions of 40 to 45% and solvent recoveries of greater than 70%.

North America Natural Gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Natural gas production (MMcf/d)	**1,698**	1,594	1,340	**1,626**	1,393
Net wells targeting natural gas	**9**	9	9	**40**	21
Net successful wells drilled	**9**	9	9	**40**	21
Success rate	**100%**	100%	100%	**100%**	100%

▪ North America natural gas production was strong in Q3/21 averaging 1,698 MMcf/d, increases of 27% and 7% from Q3/20 and Q2/21 levels respectively. The increase from Q3/20 was primarily the result of acquired production in Q4/20 and strong drilling results, partially offset by natural field declines. The increase from Q2/21 levels primarily reflects reinstated production volumes from the Pine River Gas Plant, acquisitions, and strong drilling results, partially offset by natural field declines.

- North America natural gas operating costs in Q3/21 averaged $1.14/Mcf, comparable with Q2/21 levels.

▪ As part of the 2021 budget, in the liquids-rich Montney area, the Company targets to utilize facility capacity through its drill-to-fill strategy adding low cost, high value liquids rich natural gas production volumes.

- At Septimus, production additions from the 5 net well pad completed in June 2021, brought the facility to full capacity of 150 MMcf/d of natural gas and 9,000 bbl/d of liquids. As a result of the strong performance of this pad, the facility is targeted to remain at full capacity into early 2022.
    - Operating costs at Septimus remained strong in Q3/21, averaging $0.25/Mcfe, a decrease of 22% from Q2/21 levels. The decrease in operating costs was primarily the result of the Company's drill to fill strategy and maximizing operational and cost efficiencies in the quarter.

▪ Production at Townsend of 284 MMcf/d of natural gas was achieved in Q3/21, an increase of 7% over Q2/21 levels.

- Due to a recent BC court decision, all development activities at Townsend have been temporarily suspended with 9 wells that are awaiting facilities and pipeline permit approvals. Capital has been redeployed into our deep inventory of natural gas opportunities in northwest Alberta with similar strong drill-to-fill capital efficiencies and production volume profiles.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Crude oil production (bbl/d)					
North Sea	**16,294**	16,458	21,220	**17,557**	25,186
Offshore Africa	**13,531**	16,239	17,537	**13,882**	16,977
Natural gas production (MMcf/d)					
North Sea	**2**	4	5	**3**	14
Offshore Africa	**8**	16	17	**11**	14
Net wells targeting crude oil	**1.9**	1.0	—	**4.9**	1.0
Net successful wells drilled	**1.9**	1.0	—	**4.9**	1.0
Success rate	**100%**	100%	—%	**100%**	100%

- International E&P crude oil production volumes averaged 29,825 bbl/d in Q3/21, decreases of 23% and 9% from Q3/20 and Q2/21 levels respectively. The fluctuations in production from prior periods primarily reflects planned maintenance activities and natural field declines.
  - Crude oil operating costs increased from prior periods primarily due to lower production volumes as a result of planned maintenance activities in the North Sea and Offshore Africa. Increased costs from prior periods also reflects the timing of liftings from various fields that have different cost structures in addition to fluctuations in the Canadian dollar.
  - During Q3/21 the Company completed the planned turnaround at the Ninian Central platform in the North Sea. The planned maintenance activities at Espoir in Offshore Africa were completed subsequent to quarter end. Targeted production impacts are included in the Company's annual 2021 budgeted production volume range.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Nine Months Ended	
	Sep 30 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Synthetic crude oil production (bbl/d) (1) (2)	**468,126**	361,707	350,633	**432,876**	417,439

(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 averaged strong quarterly production of 468,126 bbl/d of SCO in Q3/21, increases of 34% and 29% from Q3/20 and Q2/21 levels respectively and comparable to the record average quarterly production volumes achieved in Q1/21. Strong Q3/21 production performance was due to the Company's focus on continuous improvement, effective and efficient operations as well as planned turnaround activities completed during prior periods.
  - Following recently completed maintenance and turnaround activities across the Oil Sands Mining and Upgrading assets, top tier performance and utilization resulted in industry leading operating costs. During the first nine months of 2021, as a result of the successful completion of the Scotford turnaround and expansion in 2020, the Company has increased sales volumes by over 20,000 bbl/d of SCO.
  - Operating costs from the Company's Oil Sands Mining and Upgrading assets were strong and remain top tier averaging $19.86/bbl (US$15.76/bbl) of SCO during Q3/21, a decrease of 22% from Q2/21 levels. The decrease from Q2/21 was primarily due to strong production volumes, the Company's culture of continuous improvement and planned turnaround activities completed during the prior period.
  - Oil Sands Mining and Upgrading continue to be top tier with production volumes for October 2021 of approximately 477,000 bbl/d of SCO.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) [1]	**$ 70.55**	$ 66.06	$ 40.94	**$ 64.85**	$ 38.30
WCS heavy differential as a percentage of WTI (%) [2]	**19%**	17%	22%	**19%**	36%
SCO price (US$/bbl)	**$ 68.98**	$ 66.49	$ 38.61	**$ 63.31**	$ 35.11
Condensate benchmark pricing (US$/bbl)	**$ 69.22**	$ 66.39	$ 37.55	**$ 64.58**	$ 35.10
Average realized pricing before risk management (C$/bbl) [3]	**$ 68.06**	$ 61.20	$ 40.14	**$ 60.53**	$ 28.91
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 3.36**	$ 2.70	$ 2.03	**$ 2.95**	$ 1.96
Average realized pricing before risk management (C$/Mcf)	**$ 4.13**	$ 3.17	$ 2.31	**$ 3.59**	$ 2.19

(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.

- Crude oil prices continue to improve with WTI averaging US$70.55/bbl in Q3/21, increases of 72% and 7% from Q3/20 and Q2/21 levels respectively. The increase in WTI from comparable periods primarily reflects increased demand, the continuation of agreements by OPEC+ to maintain the majority of production cuts implemented in 2020 and the strengthening of the global economy.
  - As at November 2, 2021 for crude oil, annual WTI pricing of US$69.22/bbl is currently 76% higher than 2020 levels and the annual WCS heavy oil differential, currently at approximately a 19% discount to WTI, is in line with average historical levels.
- Natural gas prices continue to improve with AECO averaging $3.36/GJ in Q3/21, increases of 66% and 24% from Q3/20 and Q2/21 levels respectively. The increase in natural gas prices from the comparable periods primarily reflects lower storage levels and increased NYMEX benchmark pricing.
- Market egress has improved as Enbridge's Line 3 pipeline replacement began operations on October 1, 2021, increasing incremental transportation throughout the month of October.
  - November 2021 is expected to be the first full month of incremental crude oil transportation of approximately 370,000 bbl/d on Enbridge's Line 3 pipeline, increasing crude oil egress from western Canada.
- Improved performance at the North West Redwater ("NWR") Refinery continues to increase local demand for heavy crude oil.
- Construction on the 590,000 bbl/d Trans Mountain Expansion targets an on stream date in early 2023, on which Canadian Natural has committed 94,000 bbl/d.

FINANCIAL REVIEW

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

- The Company’s strategy to maintain a diverse portfolio, balanced across various commodity types, averaged quarterly production of 1,237,503 BOE/d in Q3/21, with approximately 99% of total production located in G7 countries.

- In Q3/21, reflecting the strength of our effective and efficient operations and our high quality, long life low decline asset base, Canadian Natural generated robust quarterly free cash flow of $2,195 million, after dividend payments of $558 million and net capital expenditures of $881 million, excluding acquisitions.
- Returns to shareholders year to date in 2021 have been significant, as Canadian Natural has returned approximately $3.1 billion by way of dividends and share repurchases up to and including November 3, 2021.
    - Share repurchases for cancellation during Q3/21 per the free cash flow allocation policy, totaled 11,984,400 shares or 1% of common shares outstanding at a weighted average price of $42.26 per share. Share repurchases for cancellation in 2021 up to and including November 3, 2021 total 21,464,400 common shares at a weighted average price of $43.77 per share.
    - Subsequent to quarter end the Board of Directors has approved a 25% increase to our quarterly dividend to $0.5875 per share, payable on January 5, 2022. The increased dividend clearly demonstrates the confidence that the Board of Directors have in the sustainability of our business model, the strength of our balance sheet and the Company's effective and efficient operations supported by our robust, long life low decline asset base and associated low maintenance capital requirements.
        - With this increase, 2022 will mark the 22nd consecutive year of dividend increases for the Company, and this 25% increase from our previous quarterly dividend is in excess of our historical dividend compound annual growth rate of 20% over the last 22 years.
- Canadian Natural executed on our commitment to further strengthen our balance sheet with strong financial results in Q3/21, reducing net debt by approximately $2.3 billion from Q2/21 levels, while net debt has decreased by approximately $5.8 billion over the last 12 months ended September 30, 2021.
    - On August 16, 2021 the Company repaid the US$500 million 3.45% notes originally due November 15, 2021.
    - During Q3/21 the Company repaid $500 million on its' $2,650 million term credit facility due February 2023.
        - Subsequent to quarter end the Company repaid an additional $1,000 million, which reduced the facility balance to $1,150 million as at November 3, 2021.
- As at September 30, 2021, the Company had undrawn revolving bank credit facilities of approximately $5.0 billion. Including cash and cash equivalents and short-term investments, the Company had significant liquidity of approximately $6.2 billion. At September 30, 2021, the Company did not have any funds drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
- Effective July 1, 2021 our free cash flow allocation policy authorized management to increase returns to shareholders through accelerated share repurchases under the Company's NCIB by targeting the repurchase of approximately 1% of shares outstanding per quarter. This policy further states that once the Company reaches an absolute debt level of $15 billion, currently targeted to occur in Q4/21, 50% of free cash flow will be targeted to share repurchases, with the remaining 50% of free cash flow allocated to further strengthen our balance sheet. Per this policy, the Company repurchased approximately 12 million shares in the quarter and year-to-date as of November 3, 2021 we have repurchased a total of approximately 21.5 million shares for approximately $940 million. Subsequent to quarter end, and as an enhancement to the free cash flow allocation policy, the Board of Directors has authorized management to target absolute debt at levels below $15 billion (approximately 1.0 times debt to EBITDA in the current price environment). To the extent debt is below $15 billion, such amount will be available for strategic growth/acquisition opportunities.
- During Q3/21, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, which expire August 2023, replacing the Company's previous base shelf prospectuses which would have expired in August 2021. 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.

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 continued improvement in the Company's environmental performance.

2020 Stewardship Report

Canadian Natural published its 2020 Stewardship Report to Stakeholders in August 2021, which is available on the Company's website at https://www.cnrl.com/report-to-stakeholders. The report displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing its environmental footprint. Canadian Natural outlined its pathway to lower carbon emissions and its journey to achieve its goal of net zero GHG emissions in the oil sands. Highlights from the Company's 2020 report are as follows:

- Canadian Natural's corporate GHG emissions intensity continues to improve, decreasing by 18% from 2016 to 2020, a material reduction in emissions intensity.
- The Company reduced methane emissions in its North American E&P segment by 28% from 2016 to 2020.
- The Company continues to improve corporate total recordable injury frequency ("TRIF") in 2020, with a TRIF of 0.21 in 2020 compared to 0.50 in 2016. The Company's TRIF is down 58% since 2016, while man-hours have increased over this time period.
- Canadian Natural is one of the largest owners of Carbon Capture and Storage ("CCS") and sequestration capacity in the oil and natural gas sector globally through projects at Horizon, the Company’s 70% owned Quest CCS facility located at Scotford, and its 50% working interest in the NWR Refinery. As part of our comprehensive GHG emissions reduction strategy, our CCS projects include carbon dioxide ("CO_2") storage in geological formations, the use of CO_2 in enhanced oil recovery techniques and injection of CO_2 into tailings. Gross carbon capture capacity through these projects combined is approximately 2.7 million tonnes of CO_2 annually, equivalent to taking approximately 576,000 cars off the road per year.
- The Quest Carbon Capture, Utilization and Storage ("CCUS") (70% Company ownership) facility captures and stores approximately 1.1 million tonnes of CO_2 per year, the equivalent of removing approximately 235,000 cars off the road annually. In May 2020 Quest reached the milestone of 5 million tonnes of stored carbon dioxide, equal to the emissions from approximately 1.25 million cars.
  - At Horizon, annual capture capacity is approximately 0.4 million tonnes of CO_2 from the hydrogen plant, the equivalent of removing approximately 85,000 cars off the road annually.
  - At the NWR Refinery, captured CO_2 is delivered to the Alberta Carbon Truck Line for enhanced oil recovery and permanent storage in central Alberta. At full capacity, approximately 1.2 million tonnes of CO_2 per year is targeted to be captured, the equivalent of removing approximately 256,000 cars off the road annually.
- The Company continues to increase the level of third party verified direct GHG emissions and indirect energy use.
  - The Company targets to increase the total corporate level of third party verification of GHG emissions to 95% in 2021, an increase of 9% from 2020 levels of 87%.
- In 2020 the Company planted its one millionth tree at AOSP and its one and a half millionth tree at Horizon, reclaiming land and contributing to increased carbon capture.

Oil Sands Pathway to Net Zero Initiative

On June 9, 2021 Canadian Natural together with oil sands industry participants formally announced the Oil Sands Pathways to Net Zero initiative. Canadian Natural and these companies operate approximately 90% of Canada’s oil sands production. The goal of this unique alliance, working collectively with the federal and Alberta governments, is to achieve net zero GHG emissions from oil sands operations by 2050 to help Canada meet its climate goals, including its Paris Agreement commitments and 2050 net zero aspirations.

- This collaborative effort follows welcome announcements from the Government of Canada and the Government of Alberta of important support programs for emissions-reduction projects and infrastructure. Collaboration between industry and government will be critical to progressing the Oil Sands Pathways to Net Zero vision and achieving Canada’s climate goals.
- The Pathways vision is anchored by a major CCUS trunkline connected to a carbon sequestration hub to enable multi-sector ‘tie-in’ projects for expanded emissions reductions. The proposed CCUS system will involve significant

collaboration between industry and government, which is similar to the Longship/Northern Lights project in Norway as well as other CCUS projects in the Netherlands, UK and USA.

- The Pathways initiative is ambitious and will require significant investment on the part of both industry and government to advance the research and development of new and emerging technologies.
- The companies involved look forward to continuing to work with governments and to engage with Indigenous and local communities in northern Alberta, to make this ambitious, major emissions-reduction vision a reality so those communities can continue to benefit from Canadian resource development.

Government Support for Carbon Capture, Utilization and Storage

The Government of Canada has recognized the important role of carbon capture, utilization and storage projects for the oil sands sector to continue contributing to Canada's economic growth while working towards climate objectives. Canadian Natural is a leader in CCUS and GHG reduction projects and sees many opportunities for industry to advance investments in CCUS projects. Details of the proposed government programs to support CCUS are important and the Company looks forward to continuing to provide input as government finalizes its plans.

ENVIRONMENTAL TARGETS

- As previously announced in August 2021, Canadian Natural has committed to new environmental targets as follows:
  - 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.
- In 2018, Canadian Natural was one of the first oil companies to announce an aspirational goal of achieving net zero emissions in its oil sands operations.
- Through the Company's participation in the Oil Sands Pathways to Net Zero Initiative with our industry partners and collaboration with the federal and Alberta governments, the Company is further refining its goal by targeting to achieve net zero emissions in its oil sands operations by 2050.
- The Company is currently working through the details with members of the net zero initiative alliance to advance key milestones to be achieved over the next decade as we accelerate related projects through the Pathways initiative.

ADVISORY

Special Note Regarding non-GAAP Financial Measures

This press release includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings (loss) from operations, adjusted funds flow and net capital expenditures. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP financial measures. The non-GAAP financial measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP financial measures to evaluate its performance. The non-GAAP financial measures should not be considered an alternative to or more meaningful than net earnings (loss), cash flows from operating activities, and cash flows used in investing activities as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP financial measure adjusted net earnings (loss) from operations is reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Financial Highlights" section of this press release and the Company's MD&A. Additionally, the non-GAAP financial measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial Highlights" section of the Company's MD&A. The non-GAAP financial measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of the Company's MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of the Company's MD&A.

Adjusted net earnings (loss) from operations is a non-GAAP financial measure that represents net earnings (loss), as determined in accordance with IFRS, as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings (loss) 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. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

Adjusted funds flow is a non-GAAP financial measure that represents cash flows from (used in) operating activities, as determined in accordance with IFRS, 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, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to North West Redwater Partnership ("NWRP"), and prepaid cost of service tolls. 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. Adjusted funds flow may not be comparable to similar measures presented by other companies.

Net capital expenditures is a non-GAAP financial measure, as determined in accordance with IFRS, that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, the repayment of NWRP subordinated debt advances, abandonment expenditures including the impact of government grant income under the provincial well-site rehabilitation programs, and the settlement of long-term debt assumed in acquisitions. 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. Net capital expenditures may not be comparable to similar measures presented by other companies.

Free cash 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 from operating activities, abandonment, certain movements in other long-term assets, less net 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.

Adjusted EBITDA is a non-GAAP financial measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for interest, taxes, depletion, depreciation and amortization, stock based compensation expense (recovery), unrealized risk management gains (losses), unrealized foreign exchange gains (losses), and accretion of the Company’s asset retirement obligation. The Company considers adjusted EBITDA a key measure in evaluating its operating profitability by excluding non-cash items.

Debt to adjusted EBITDA is a non-GAAP ratio that is derived as the current and long-term portions of long-term debt, divided by the 12 month trailing Adjusted EBITDA, as defined above. The Company considers this ratio to be a key measure in evaluating the Company's ability to pay off its debt.

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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 Oil Sands Pathway to Net Zero Initiative, 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, 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, and the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long-term 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 and the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+")) which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil and natural gas and NGLs prices including due to actions of OPEC+ taken in response to COVID-19 or otherwise; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities (including production curtailments mandated by the Government of Alberta); government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short, medium, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial, state and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this MD&A could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements in this MD&A, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

Special Note Regarding non-GAAP Financial Measures

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings (loss) from operations, adjusted funds flow and net capital expenditures. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP financial measures. The non-GAAP financial measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP financial measures to evaluate its performance. The non-GAAP financial measures should not be considered an alternative to or more meaningful than net earnings (loss), cash flows from operating activities, and cash flows used in investing activities as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP financial measure adjusted net earnings (loss) from operations is reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. Additionally, the non-GAAP financial measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP financial measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three and nine months ended September 30, 2021 and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2020. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2021 and this MD&A have been prepared in accordance with 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, 2021 in relation to the comparable periods in 2020 and the second quarter of 2021. 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, 2020, 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 3, 2021.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Sep 30 2021	Jun 30 2021	Sep 30 2020	Nine Months Ended Sep 30 2021	Sep 30 2020
Product sales [1]	**$ 8,521**	$ 7,124	$ 4,676	**$ 22,664**	$ 12,272
Crude oil and NGLs	**$ 7,607**	$ 6,382	$ 4,202	**$ 20,277**	$ 10,987
Natural gas	**$ 694**	$ 509	$ 338	**$ 1,758**	$ 982
Net earnings (loss)	**$ 2,202**	$ 1,551	$ 408	**$ 5,130**	$ (1,184)
Per common share – basic	**$ 1.87**	$ 1.31	$ 0.35	**$ 4.33**	$ (1.00)
– diluted	**$ 1.86**	$ 1.30	$ 0.35	**$ 4.32**	$ (1.00)
Adjusted net earnings (loss) from operations [2]	**$ 2,095**	$ 1,480	$ 135	**$ 4,794**	$ (932)
Per common share – basic	**$ 1.78**	$ 1.25	$ 0.11	**$ 4.05**	$ (0.79)
– diluted	**$ 1.77**	$ 1.24	$ 0.11	**$ 4.04**	$ (0.79)
Cash flows from operating activities	**$ 4,290**	$ 2,940	$ 2,070	**$ 9,766**	$ 3,444
Adjusted funds flow [3]	**$ 3,634**	$ 3,049	$ 1,740	**$ 9,395**	$ 3,492
Per common share – basic	**$ 3.08**	$ 2.57	$ 1.47	**$ 7.94**	$ 2.96
– diluted	**$ 3.07**	$ 2.56	$ 1.47	**$ 7.91**	$ 2.96
Cash flows used in investing activities	**$ 721**	$ 719	$ 643	**$ 2,088**	$ 2,195
Net capital expenditures [4]	**$ 1,011**	$ 1,285	$ 771	**$ 3,104**	$ 2,030

(1) Further details related to product sales are disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

(2) Adjusted net earnings (loss) from operations is a non-GAAP financial measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings (loss) 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. The reconciliation "Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)" is presented in this MD&A. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

(3) 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, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to North West Redwater Partnership ("NWRP"), and prepaid cost of service tolls. 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. The reconciliation "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" is presented in this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.

(4) 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. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the "Net Capital Expenditures" section of this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)

($ millions)	Three Months Ended Sep 30 2021	Three Months Ended Jun 30 2021	Three Months Ended Sep 30 2020	Nine Months Ended Sep 30 2021	Nine Months Ended Sep 30 2020
Net earnings (loss)	***$ 2,202***	*$ 1,551*	*$ 408*	***$ 5,130***	*$ (1,184)*
Share-based compensation, net of tax [1]	***54***	*132*	*(5)*	***312***	*(203)*
Unrealized risk management (gain) loss, net of tax [2]	***(15)***	*6*	*(1)*	***6***	*(15)*
Unrealized foreign exchange loss (gain), net of tax [3]	***197***	*(151)*	*(270)*	***(126)***	*418*
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax [4]	***118***	*—*	*—*	***118***	*—*
Realized foreign exchange gain on settlement of cross currency swaps, net of tax [5]	***—***	*—*	*—*	***—***	*(166)*
Gain on acquisitions, net of tax [6]	***(478)***	*—*	*—*	***(478)***	*—*
Loss (gain) from investments, net of tax [7]	***35***	*(47)*	*3*	***(129)***	*218*
Other, net of tax [8]	***(18)***	*(11)*	*—*	***(39)***	*—*
Adjusted net earnings (loss) from operations	***$ 2,095***	*$ 1,480*	*$ 135*	***$ 4,794***	*$ (932)*

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("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 (loss).

(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 (loss). 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.

(3) Unrealized foreign exchange gains and losses 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 (loss).

(4) During the third quarter of 2021, the Company repaid US$500 million of 3.45% debt securities, originally due November 2021, resulting in a pre- and after-tax foreign exchange loss of $118 million.

(5) During the first quarter of 2020, the Company settled the US$500 million cross currency swaps designated as cash flow hedges of the US$500 million 3.45% US dollar debt securities due November 2021. The Company realized cash proceeds of $166 million on settlement.

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

(7) The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("IPL") have been accounted for at fair value through profit and loss and are measured each period with (gains) losses recognized in net earnings (loss).

(8) "Other" reflects the after-tax impact of government grant income under the provincial well-site rehabilitation programs.

Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities

($ millions)	Three Months Ended Sep 30 2021	Three Months Ended Jun 30 2021	Three Months Ended Sep 30 2020	Nine Months Ended Sep 30 2021	Nine Months Ended Sep 30 2020
Cash flows from operating activities	***$ 4,290***	*$ 2,940*	*$ 2,070*	***$ 9,766***	*$ 3,444*
Net change in non-cash working capital	***(691)***	*137*	*(372)*	***(544)***	*(228)*
Abandonment expenditures [1]	***54***	*44*	*68*	***165***	*197*
Other [2]	***(19)***	*(72)*	*(26)*	***8***	*79*
Adjusted funds flow	***$ 3,634***	*$ 3,049*	*$ 1,740*	***$ 9,395***	*$ 3,492*

(1) The Company includes abandonment expenditures in "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" in the "Net Capital Expenditures" section of this MD&A and excludes the impact of government grant income under the provincial well-site rehabilitation programs.

(2) Movements in other long-term assets, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to NWRP and prepaid cost of service tolls.

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings (Loss) and Adjusted Net Earnings (Loss) from Operations

Net earnings for the nine months ended September 30, 2021 were $5,130 million compared with a net loss of $1,184 million for the nine months ended September 30, 2020. Net earnings for the nine months ended September 30, 2021 included net after-tax income of $336 million compared with net after-tax expenses of $252 million for the nine months ended September 30, 2020 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange loss on repayment of US dollar debt securities, the foreign exchange gain on the settlement of the cross currency swaps, the gain on acquisitions, the loss (gain) 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, 2021 were $4,794 million compared with an adjusted net loss from operations of $932 million for the nine months ended September 30, 2020.

Net earnings for the third quarter of 2021 were $2,202 million compared with $408 million for the third quarter of 2020 and $1,551 million for the second quarter of 2021. Net earnings for the third quarter of 2021 included net after-tax income of $107 million compared with net after-tax income of $273 million for the third quarter of 2020 and net after-tax income of $71 million for the second quarter of 2021 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange loss on repayment of US dollar debt securities, the gain on acquisitions, the loss (gain) 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 2021 were $2,095 million compared with $135 million for the third quarter of 2020 and $1,480 million for the second quarter of 2021.

Net earnings and adjusted net earnings from operations for the nine months ended September 30, 2021 compared with a net loss and an adjusted net loss from operations for the nine months ended September 30, 2020 primarily reflected:

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

partially offset by:

- higher production costs in the Oil Sands Mining and Upgrading segment; and
- higher realized foreign exchange losses.

Net earnings and adjusted net earnings from operations for the third quarter of 2021 compared with net earnings and adjusted net earnings from operations for the third quarter of 2020 and the second quarter of 2021 primarily reflected:

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

partially offset by:

- lower crude oil and NGLs sales volumes in the Exploration and Production segments.

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

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the nine months ended September 30, 2021 were $9,766 million compared with $3,444 million for the nine months ended September 30, 2020. Cash flows from operating activities for the third quarter of 2021 were $4,290 million compared with $2,070 million for the third quarter of 2020 and $2,940 million for the second quarter of 2021. 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 net earnings (loss) from operations, as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the nine months ended September 30, 2021 was $9,395 million compared with $3,492 million for the nine months ended September 30, 2020. Adjusted funds flow for the third quarter of 2021 was $3,634 million compared with $1,740 million for the third quarter of 2020 and $3,049 million for the second quarter of 2021. 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, accrued interest on subordinated debt advances to NWRP, and prepaid cost of service tolls.

Production Volumes

Crude oil and NGLs production before royalties for the third quarter of 2021 increased 8% to 952,839 bbl/d, from 884,342 bbl/d for the third quarter of 2020 and increased 9% from 872,718 bbl/d for the second quarter of 2021. Natural gas production before royalties for the third quarter of 2021 increased 25% to 1,708 MMcf/d from 1,362 MMcf/d for the third quarter of 2020 and increased 6% from 1,614 MMcf/d for the second quarter of 2021. Total production before royalties for the third quarter of 2021 of 1,237,503 BOE/d increased 11% from 1,111,286 BOE/d for the third quarter of 2020 and increased 8% from 1,141,739 BOE/d for the second quarter of 2021. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

Product Prices

In the Company's Exploration and Production segments, crude oil and NGLs realized prices averaged $68.06 per bbl for the third quarter of 2021, an increase of 70% compared with $40.14 per bbl for the third quarter of 2020, and an increase of 11% from $61.20 per bbl for the second quarter of 2021. The natural gas realized price increased 79% to average $4.13 per Mcf for the third quarter of 2021 from $2.31 per Mcf for the third quarter of 2020, and increased 30% from $3.17 per Mcf for the second quarter of 2021. In the Oil Sands Mining and Upgrading segment, the Company's SCO realized price increased 67% to average $81.54 per bbl for the third quarter of 2021 from $48.92 per bbl for the third quarter of 2020, and increased 7% from $76.19 per bbl for the second quarter of 2021. The Company's realized pricing reflects prevailing benchmark pricing. Crude oil and NGLs and natural gas prices are discussed in detail in the "Business Environment", "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 averaged $14.78 per bbl for the third quarter of 2021, an increase of 34% from $11.03 per bbl for the third quarter of 2020, and an increase of 7% from $13.75 per bbl for the second quarter of 2021. Natural gas production expense averaged $1.17 per Mcf for the third quarter of 2021, comparable with $1.18 per Mcf for the third quarter of 2020 and $1.19 per Mcf for the second quarter of 2021. In the Oil Sands Mining and Upgrading segment, production costs averaged $19.86 per bbl for the third quarter of 2021, a decrease of 17% from $23.81 per bbl for the third quarter of 2020, and a decrease of 22% from $25.46 per bbl for the second quarter of 2021. 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 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 (loss)	**$ 2,202**	$ 1,551	$ 1,377	$ 749
Net earnings (loss) per common share				
– basic	**$ 1.87**	$ 1.31	$ 1.16	$ 0.63
– diluted	**$ 1.86**	$ 1.30	$ 1.16	$ 0.63

($ millions, except per common share amounts)	Sep 30 2020	Jun 30 2020	Mar 31 2020	Dec 31 2019
Product sales [(1)]	$ 4,676	$ 2,944	$ 4,652	$ 6,335
Crude oil and NGLs	$ 4,202	$ 2,462	$ 4,323	$ 5,947
Natural gas	$ 338	$ 307	$ 337	$ 382
Net earnings (loss)	$ 408	$ (310)	$ (1,282)	$ 597
Net earnings (loss) per common share				
– basic	$ 0.35	$ (0.26)	$ (1.08)	$ 0.50
– diluted	$ 0.35	$ (0.26)	$ (1.08)	$ 0.50

(1) Further details related to product sales for the three months ended September 30, 2021 and 2020 are disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

Volatility in the quarterly net earnings (loss) 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, 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 North Sea and Offshore Africa; and the impact of production curtailments mandated by the Government of Alberta that came into effect on January 1, 2019 and 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, 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 Company's 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 came into effect January 1, 2019 and 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 allocation of capital to high return projects, drilling results, natural decline rates, the temporary shut-down and subsequent reinstatement of the Pine River Gas Plant, 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 seasonality, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Transportation, blending, and feedstock expense** – Fluctuations due to the provision recognized relating to the cancellation of the Keystone XL pipeline project in the fourth quarter of 2020.
- **Depletion, depreciation and amortization expense** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, and the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment.
- **Share-based compensation** – Fluctuations due to the measurement of fair market value of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Interest expense** – Fluctuations due to changing long-term debt levels, and the impact of movements in benchmark interest rates on outstanding floating rate long-term debt.
- **Foreign exchange** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Gain on acquisitions, loss (gain) from investments and income from NWRP** – Fluctuations due to the recognition of gains on acquisitions, loss (gain) from the investments in PrairieSky and IPL shares, equity income and losses on the Company's interest in NWRP, and the distribution from NWRP in the second quarter of 2021.
- **Income taxes** – Fluctuations due to statutory tax rate and other legislative changes substantively enacted in the various periods.

BUSINESS ENVIRONMENT

Global benchmark crude oil prices increased significantly through the third quarter of 2021, partially in response to the OPEC+ decision to maintain substantially all of the production cut agreements implemented in the first half of 2020. Additionally, global demand for crude oil increased due to improved economic conditions, as the effects of COVID-19 became less impactful to the global economy. Improved economic conditions continue to positively impact the outlook for crude oil prices, although market conditions remain uncertain.

During the third quarter of 2021, the Company continued to utilize federal and provincial government programs to support employment during the COVID-19 pandemic, including in Canada, the provincial well-site rehabilitation program.

Liquidity

As at September 30, 2021, the Company had undrawn revolving bank credit facilities of $4,959 million. Including cash and cash equivalents and short-term investments, the Company had approximately $6,159 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Refer to the "Liquidity and Capital Resources" section of this MD&A for further details.

Capital Spending

Safe, reliable, effective and efficient operations continue to be a focus for the Company. On December 9, 2020, the Company announced its 2021 capital budget targeted at approximately $3,205 million, of which $1,345 million was related to conventional and unconventional assets and $1,860 million was allocated to long-life low decline assets. On August 5, 2021, the 2021 capital budget was increased by $275 million to $3,480 million, excluding acquisitions. The increase included $120 million for conventional and unconventional assets, $110 million for long-life low decline assets, and $45 million for additional well abandonment activities. Production for 2021 is targeted between 1,220,000 BOE/d and 1,267,000 BOE/d. Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns and the balancing of project risks and time horizons. The 2021 capital budget and production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

During the nine months ended September 30, 2021, the Company completed three opportunistic acquisitions. The first two acquisitions consisted of natural gas assets located in the Montney region of British Columbia, with aggregate production of approximately 11,100 BOE/d, consisting of 63 MMcf/d and 600 bbl/d of NGLs, approximately 107,000 acres of Montney lands, and related processing infrastructure with approximately 140 MMcf/d of capacity. These two acquisitions build on the Company’s expansive natural gas operations in northeastern British Columbia, increasing the Company's total Montney lands to approximately 1.3 million acres. The third acquisition consisted of a net carried interest on an existing Canadian Natural oil sands lease, from which all of the Company's current Horizon volumes are derived. Total cash consideration paid for these acquisitions was approximately $450 million.

During the third quarter of 2021, in accordance with a third-party offer to purchase, the Company elected to take total cash proceeds of $128 million, or $20.00 per common share, in exchange for its 6.4 million common share investment in IPL.

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 resulting from quarantines that affect the Company’s labour pools in their local communities, workforce camps or operating sites or that are instituted by local health authorities as a precautionary measure, any of which may require the Company to temporarily reduce or shutdown its operations depending on their extent and severity.

Benchmark Commodity Prices

(Average for the period)	Three Months Ended **Sep 30 2021**	Jun 30 2021	Sep 30 2020	Nine Months Ended **Sep 30 2021**	Sep 30 2020
WTI benchmark price (US$/bbl)	**$ 70.55**	$ 66.06	$ 40.94	**$ 64.85**	$ 38.30
Dated Brent benchmark price (US$/bbl)	**$ 72.98**	$ 68.63	$ 42.74	**$ 67.44**	$ 41.51
WCS Heavy Differential from WTI (US$/bbl)	**$ 13.58**	$ 11.47	$ 9.06	**$ 12.50**	$ 13.67
SCO price (US$/bbl)	**$ 68.98**	$ 66.49	$ 38.61	**$ 63.31**	$ 35.11
Condensate benchmark price (US$/bbl)	**$ 69.22**	$ 66.39	$ 37.55	**$ 64.58**	$ 35.10
Condensate Differential from WTI (US$/bbl)	**$ 1.33**	$ (0.33)	$ 3.39	**$ 0.27**	$ 3.20
NYMEX benchmark price (US$/MMBtu)	**$ 4.01**	$ 2.83	$ 1.97	**$ 3.18**	$ 1.88
AECO benchmark price (C$/GJ)	**$ 3.36**	$ 2.70	$ 2.03	**$ 2.95**	$ 1.96
US/Canadian dollar average exchange rate (US$)	**$ 0.7936**	$ 0.8143	$ 0.7507	**$ 0.7992**	$ 0.7384

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 highly sensitive to 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$64.85 per bbl for the nine months ended September 30, 2021, an increase of 69% from US$38.30 per bbl for the nine months ended September 30, 2020. WTI averaged US$70.55 per bbl for the third quarter of 2021, an increase of 72% from US$40.94 per bbl for the third quarter of 2020, and an increase of 7% from US$66.06 per bbl for the second quarter of 2021.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$67.44 per bbl for the nine months ended September 30, 2021, an increase of 62% from US$41.51 per bbl for the nine months ended September 30, 2020. Brent averaged US$72.98 per bbl for the third quarter of 2021, an increase of 71% from US$42.74 per bbl for the third quarter of 2020, and an increase of 6% from US$68.63 per bbl for the second quarter of 2021.

The increase in WTI and Brent pricing for the three and nine months ended September 30, 2021 from the comparable periods in 2020 primarily reflected the OPEC+ decision to maintain substantially all of the production cut agreements that were implemented in the first half of 2020. Additionally, global demand for crude oil increased due to improved economic conditions. The increase in WTI and Brent pricing for the third quarter of 2021 from the second quarter of 2021 primarily reflected the continued recovery of global demand.

The WCS Heavy Differential averaged US$12.50 per bbl for the nine months ended September 30, 2021, a narrowing of 9% from US$13.67 per bbl for the nine months ended September 30, 2020. The WCS Heavy Differential averaged US$13.58 per bbl for the third quarter of 2021, a widening of 50% from US$9.06 per bbl for the third quarter of 2020, and a widening of 18% from US$11.47 per bbl for the second quarter of 2021. The widening of the WCS Heavy Differential for the third quarter of 2021 from the comparable periods primarily reflected increases in WTI benchmark pricing and the widening of the US Gulf Coast heavy oil pricing.

The SCO price averaged US$63.31 per bbl for the nine months ended September 30, 2021, an increase of 80% from US$35.11 per bbl for the nine months ended September 30, 2020. The SCO price averaged US$68.98 per bbl for the third quarter of 2021, an increase of 79% from US$38.61 per bbl for the third quarter of 2020, and an increase of 4% from US$66.49 per bbl for the second quarter of 2021. The increase in SCO pricing for the three and nine months ended September 30, 2021 from the comparable periods primarily reflected increases in WTI benchmark pricing.

NYMEX natural gas prices averaged US$3.18 per MMBtu for the nine months ended September 30, 2021, an increase of 69% from US$1.88 per MMBtu for the nine months ended September 30, 2020. NYMEX natural gas prices averaged US$4.01 per MMBtu for the third quarter of 2021, an increase of 104% from US$1.97 per MMBtu for the third quarter of 2020, and an increase of 42% from US$2.83 per MMBtu for the second quarter of 2021. The increase in NYMEX natural gas prices for the three and nine months ended September 30, 2021 from the comparable periods in 2020 primarily reflected increased North American demand in 2021, following the impact of COVID-19 in 2020, as well as lower storage levels. The increase in NYMEX natural gas prices for the third quarter of 2021 from the second quarter of 2021 primarily reflected increased international Liquefied Natural Gas prices, together with low storage levels.

AECO natural gas prices averaged $2.95 per GJ for the nine months ended September 30, 2021, an increase of 51% from $1.96 per GJ for the nine months ended September 30, 2020. AECO natural gas prices averaged $3.36 per GJ for the third quarter of 2021, an increase of 66% from $2.03 per GJ for the third quarter of 2020, and an increase of 24% from $2.70 per GJ for the second quarter of 2021. The increase in AECO natural gas prices for the three and nine months ended September 30, 2021 from the comparable periods primarily reflected lower storage levels and increased NYMEX benchmark pricing.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**454,888**	478,314	494,952	**470,558**	455,257
North America – Oil Sands Mining and Upgrading [1]	**468,126**	361,707	350,633	**432,876**	417,439
North Sea	**16,294**	16,458	21,220	**17,557**	25,186
Offshore Africa	**13,531**	16,239	17,537	**13,882**	16,977
	952,839	872,718	884,342	**934,873**	914,859
Natural gas (MMcf/d)					
North America	**1,698**	1,594	1,340	**1,626**	1,393
North Sea	**2**	4	5	**3**	14
Offshore Africa	**8**	16	17	**11**	14
	1,708	1,614	1,362	**1,640**	1,421
Total barrels of oil equivalent (BOE/d)	**1,237,503**	1,141,739	1,111,286	**1,208,285**	1,151,693
Product mix					
Light and medium crude oil and NGLs	**10%**	11%	11%	**10%**	11%
Pelican Lake heavy crude oil	**4%**	5%	5%	**5%**	5%
Primary heavy crude oil	**5%**	6%	6%	**5%**	6%
Bitumen (thermal oil)	**20%**	23%	26%	**21%**	21%
Synthetic crude oil [1]	**38%**	32%	32%	**36%**	36%
Natural gas	**23%**	23%	20%	**23%**	21%
Percentage of gross revenue [1] [2] (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**91%**	92%	93%	**92%**	92%
Natural gas	**9%**	8%	7%	**8%**	8%

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

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**386,416**	407,111	455,393	**405,086**	416,611
North America – Oil Sands Mining and Upgrading	**421,483**	331,214	347,475	**400,239**	413,941
North Sea	**16,256**	16,380	21,150	**17,508**	25,122
Offshore Africa	**12,901**	15,531	16,767	**13,258**	16,269
	837,056	770,236	840,785	**836,091**	871,943
Natural gas (MMcf/d)					
North America	**1,609**	1,532	1,298	**1,550**	1,357
North Sea	**2**	4	5	**3**	14
Offshore Africa	**7**	16	16	**11**	14
	1,618	1,552	1,319	**1,564**	1,385
Total barrels of oil equivalent (BOE/d)	**1,106,743**	1,028,908	1,060,629	**1,096,779**	1,102,742

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, 2021 averaged 934,873 bbl/d, an increase of 2% from 914,859 bbl/d for the nine months ended September 30, 2020. Crude oil and NGLs production for the third quarter of 2021 averaged 952,839 bbl/d, an increase of 8% from 884,342 bbl/d for the third quarter of 2020, and an increase of 9% from 872,718 bbl/d for the second quarter of 2021. The increase in crude oil and NGLs production for the nine months ended September 30, 2021 from the comparable period in 2020 primarily reflected the completion of expansion activities at the Scotford Upgrader ("Scotford") in the prior year, and high utilization at Jackfish. The increase in crude oil and NGLs production for the third quarter of 2021 from the comparable periods primarily reflected the timing of turnaround activities in the Oil Sands Mining and Upgrading segment, partially offset by planned turnaround activities at Jackfish in the third quarter of 2021. Crude oil and NGLs production in North America Exploration and Production and Oil Sands Mining and Upgrading segments for the comparable periods in 2020 reflected the impact of the Company's curtailment optimization strategy during mandatory Government of Alberta curtailment.

Natural gas production before royalties for the nine months ended September 30, 2021 of 1,640 MMcf/d increased 15% from 1,421 MMcf/d for the nine months ended September 30, 2020. Natural gas production for the third quarter of 2021 of 1,708 MMcf/d increased 25% from 1,362 MMcf/d for the third quarter of 2020, and increased 6% from 1,614 MMcf/d for the second quarter of 2021. The increase in natural gas production for the three and nine months ended September 30, 2021 from the comparable periods in 2020 primarily reflected production volumes from the acquisition in 2020, and strong drilling results, partially offset by natural field declines. The increase in natural gas production for the third quarter of 2021 from the second quarter of 2021 primarily reflected reinstated volumes from the Pine River Gas Plant, acquisitions, and strong drilling results, partially offset by natural field declines.

Annual crude oil and NGLs production for 2021 is targeted to average between 940,000 bbl/d and 980,000 bbl/d. Annual natural gas production for 2021 is targeted to average between 1,680 MMcf/d and 1,720 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, 2021 averaged 470,558 bbl/d, an increase of 3% from 455,257 bbl/d for the nine months ended September 30, 2020. North America crude oil and NGLs production for the third quarter of 2021 of 454,888 bbl/d decreased 8% from 494,952 bbl/d for the third quarter of 2020, and decreased 5% from 478,314 bbl/d for the second quarter of 2021. The increase in crude oil and NGLs production for the nine months ended September 30, 2021 from the comparable period in 2020 primarily reflected the impact of the suspension of mandatory Government of Alberta curtailment on December 1, 2020. The decrease in production for the third quarter of 2021 from the comparable periods primarily reflected decreased thermal oil production due to planned turnaround activities at Jackfish in the third quarter of 2021 and natural field declines. The decrease in production for the third quarter of 2021 from the second quarter of 2021 also reflected decreased NGLs production primarily due to third-party outages.

Thermal oil production before royalties for the third quarter of 2021 averaged 248,113 bbl/d, a decrease of 14% from 287,978 bbl/d for the third quarter of 2020, and a decrease of 4% from 258,551 bbl/d for the second quarter of 2021. The decrease in thermal oil production for the third quarter of 2021 from the comparable periods primarily reflected planned turnaround activities at Jackfish in the third quarter of 2021 and natural field declines.

Pelican Lake heavy crude oil production before royalties averaged 53,923 bbl/d for the third quarter of 2021, a decrease of 4% from 56,392 bbl/d for the third quarter of 2020, and comparable with 55,212 bbl/d for the second quarter of 2021, demonstrating Pelican Lake's long-life low decline production.

Natural gas production before royalties for the nine months ended September 30, 2021 averaged 1,626 MMcf/d, an increase of 17% from 1,393 MMcf/d for the nine months ended September 30, 2020. Natural gas production for the third quarter of 2021 averaged 1,698 MMcf/d, an increase of 27% from 1,340 MMcf/d for the third quarter of 2020, and an increase of 7% from 1,594 MMcf/d for the second quarter of 2021. The increase in natural gas production for the three and nine months ended September 30, 2021 from the comparable periods in 2020 primarily reflected production volumes from the acquisition in 2020 and strong drilling results, partially offset by natural field declines. The increase in natural gas production for the third quarter of 2021 from the second quarter of 2021 primarily reflected reinstated volumes from the Pine River Gas Plant, acquisitions, and strong drilling results, partially offset by natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the nine months ended September 30, 2021 of 432,876 bbl/d increased 4% from 417,439 bbl/d for the nine months ended September 30, 2020. SCO production for the third quarter of 2021 of 468,126 bbl/d increased 34% from 350,633 bbl/d for the third quarter of 2020 and increased 29% from 361,707 bbl/d for the second quarter of 2021. The increase in SCO production for the nine months ended September 30, 2021 from the comparable period primarily reflected the completion of expansion activities at Scotford in the prior year. The increase in the third quarter of 2021 from the comparable periods primarily reflected the timing of planned turnaround activities.

North Sea

North Sea crude oil production before royalties for the nine months ended September 30, 2021 of 17,557 bbl/d decreased 30% from 25,186 bbl/d for the nine months ended September 30, 2020. North Sea crude oil production for the third quarter of 2021 of 16,294 bbl/d decreased 23% from 21,220 bbl/d for the third quarter of 2020 and was comparable with 16,458 bbl/d for the second quarter of 2021. The decrease in production for the three and nine months ended September 30, 2021 from the comparable periods in 2020 primarily reflected planned maintenance activities and natural field declines.

Offshore Africa

Offshore Africa crude oil production before royalties for the nine months ended September 30, 2021 decreased 18% to 13,882 bbl/d from 16,977 bbl/d for the nine months ended September 30, 2020. Offshore Africa crude oil production for the third quarter of 2021 of 13,531 bbl/d decreased 23% from 17,537 bbl/d for the third quarter of 2020 and decreased 17% from 16,239 bbl/d for the second quarter of 2021. The decrease in production for the three and nine months ended September 30, 2021 from the comparable periods primarily reflected planned maintenance activities at Espoir, which were completed subsequent to the third quarter of 2021.

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 2021**	Jun 30 2021	Sep 30 2020
North Sea	**295,014**	270,524	730,801
Offshore Africa	**—**	458,208	779,347
	295,014	728,732	1,510,148

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Crude oil and NGLs ($/bbl) [1]					
Sales price [2]	**$ 68.06**	$ 61.20	$ 40.14	**$ 60.53**	$ 28.91
Transportation	**4.00**	3.98	3.60	**3.84**	3.87
Realized sales price, net of transportation	**64.06**	57.22	36.54	**56.69**	25.04
Royalties	**9.46**	8.50	3.03	**7.86**	2.33
Production expense	**14.78**	13.75	11.03	**14.36**	12.41
Netback	**$ 39.82**	$ 34.97	$ 22.48	**$ 34.47**	$ 10.30
Natural gas ($/Mcf) [1]					
Sales price [2]	**$ 4.13**	$ 3.17	$ 2.31	**$ 3.59**	$ 2.19
Transportation	**0.44**	0.48	0.42	**0.46**	0.44
Realized sales price, net of transportation	**3.69**	2.69	1.89	**3.13**	1.75
Royalties	**0.22**	0.12	0.07	**0.17**	0.06
Production expense	**1.17**	1.19	1.18	**1.21**	1.21
Netback	**$ 2.30**	$ 1.38	$ 0.64	**$ 1.75**	$ 0.48
Barrels of oil equivalent ($/BOE) [1]					
Sales price [2]	**$ 52.09**	$ 46.40	$ 32.28	**$ 46.77**	$ 23.82
Transportation	**3.50**	3.58	3.28	**3.45**	3.46
Realized sales price, net of transportation	**48.59**	42.82	29.00	**43.32**	20.36
Royalties	**6.45**	5.77	2.25	**5.44**	1.69
Production expense	**11.91**	11.42	9.84	**11.85**	10.76
Netback	**$ 30.23**	$ 25.63	$ 16.91	**$ 26.03**	$ 7.91

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 66.03**	$ 59.80	$ 38.86	**$ 58.74**	$ 27.11
North Sea	**$ 96.11**	$ 85.09	$ 57.84	**$ 83.03**	$ 48.36
Offshore Africa	**$ 91.73**	$ 85.78	$ 55.11	**$ 86.92**	$ 51.74
Average	**$ 68.06**	$ 61.20	$ 40.14	**$ 60.53**	$ 28.91
Natural gas ($/Mcf) (1) (2)					
North America	**$ 4.12**	$ 3.13	$ 2.25	**$ 3.57**	$ 2.12
North Sea	**$ 3.75**	$ 2.58	$ 3.44	**$ 2.86**	$ 2.87
Offshore Africa	**$ 6.83**	$ 6.50	$ 7.32	**$ 6.46**	$ 8.22
Average	**$ 4.13**	$ 3.17	$ 2.31	**$ 3.59**	$ 2.19
Average ($/BOE) (1) (2)	**$ 52.09**	$ 46.40	$ 32.28	**$ 46.77**	$ 23.82

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

North America

North America realized crude oil and NGLs prices increased 117% to average $58.74 per bbl for the nine months ended September 30, 2021 from $27.11 per bbl for the nine months ended September 30, 2020. North America realized crude oil and NGLs prices increased 70% to average $66.03 per bbl for the third quarter of 2021 from $38.86 per bbl for the third quarter of 2020, and increased 10% from $59.80 per bbl for the second quarter of 2021. The increase in realized crude oil and NGLs prices for the three and nine months ended September 30, 2021 from the comparable periods was primarily due to higher WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and in the third quarter of 2021 contributed approximately 163,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 68% to average $3.57 per Mcf for the nine months ended September 30, 2021 from $2.12 per Mcf for the nine months ended September 30, 2020. North America realized natural gas prices increased 83% to average $4.12 per Mcf for the third quarter of 2021 from $2.25 per Mcf for the third quarter of 2020, and increased 32% from $3.13 per Mcf for the second quarter of 2021. The increase in realized natural gas prices for the three and nine months ended September 30, 2021 from the comparable periods primarily reflected lower storage levels and increased benchmark pricing.

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

	Three Months Ended		
(Quarterly average)	**Sep 30 2021**	Jun 30 2021	Sep 30 2020
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 63.88**	$ 55.81	$ 36.48
Pelican Lake heavy crude oil ($/bbl)	**$ 71.92**	$ 67.75	$ 42.97
Primary heavy crude oil ($/bbl)	**$ 68.72**	$ 64.24	$ 42.63
Bitumen (thermal oil) ($/bbl)	**$ 64.81**	$ 58.50	$ 37.78
Natural gas ($/Mcf)	**$ 4.12**	$ 3.13	$ 2.25

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

North Sea

North Sea realized crude oil and NGLs prices increased 72% to average $83.03 per bbl for the nine months ended September 30, 2021 from $48.36 per bbl for the nine months ended September 30, 2020. North Sea realized crude oil and NGLs prices increased 66% to average $96.11 per bbl for the third quarter of 2021 from $57.84 per bbl for the third quarter of 2020 and increased 13% from $85.09 per bbl for the second quarter of 2021. 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, 2021 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil and NGLs prices increased 68% to average $86.92 per bbl for the nine months ended September 30, 2021 from $51.74 per bbl for the nine months ended September 30, 2020. Offshore Africa realized crude oil and NGLs prices increased 66% to average $91.73 per bbl for the third quarter of 2021 from $55.11 per bbl for the third quarter of 2020 and increased 7% from $85.78 per bbl for the second quarter of 2021. 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, 2021 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 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 10.02**	$ 8.84	$ 3.15	**$ 8.29**	$ 2.45
North Sea	**$ 0.22**	$ 0.39	$ 0.19	**$ 0.19**	$ 0.12
Offshore Africa	**$ 4.27**	$ 3.74	$ 2.42	**$ 3.92**	$ 2.19
Average	**$ 9.46**	$ 8.50	$ 3.03	**$ 7.86**	$ 2.33
Natural gas ($/Mcf) [1]					
North America	**$ 0.22**	$ 0.12	$ 0.07	**$ 0.17**	$ 0.05
Offshore Africa	**$ 0.31**	$ 0.30	$ 0.34	**$ 0.29**	$ 0.40
Average	**$ 0.22**	$ 0.12	$ 0.07	**$ 0.17**	$ 0.06
Average ($/BOE) [1]	**$ 6.45**	$ 5.77	$ 2.25	**$ 5.44**	$ 1.69

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and natural gas royalties for the three and nine months ended September 30, 2021 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates averaged approximately 14% of product sales for the nine months ended September 30, 2021 compared with 9% of product sales for the nine months ended September 30, 2020. Crude oil and NGLs royalty rates averaged approximately 15% of product sales for the third quarter of 2021 compared with 8% for the third quarter of 2020 and 15% for the second quarter of 2021. The increase in royalty rates for the three and nine months ended September 30, 2021 from the comparable periods in 2020 was primarily due to higher benchmark prices together with fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 5% of product sales for the nine months ended September 30, 2021 compared with 3% of product sales for the nine months ended September 30, 2020. Natural gas royalty rates averaged approximately 5% of product sales for the third quarter of 2021 compared with 3% for the third quarter of 2020 and 4% for the second quarter of 2021. The increase in royalty rates for the three and nine months ended September 30, 2021 from the comparable periods was primarily due to higher benchmark prices.

Offshore Africa

Under the terms of the various Production Sharing Contracts royalty rates fluctuate based on realized commodity pricing, capital expenditures and production expenses, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 5% for the nine months ended September 30, 2021, compared with 4% of product sales for the nine months ended September 30, 2020. Royalty rates as a percentage of product sales averaged approximately 5% for the third quarter of 2021 compared with 4% of product sales for the third quarter of 2020 and 4% for the second quarter of 2021. 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 2021	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 13.33**	$ 12.82	$ 9.80	**$ 12.98**	$ 11.34
North Sea	**$ 55.90**	$ 63.65	$ 42.10	**$ 49.83**	$ 31.99
Offshore Africa	**$ 14.53**	$ 13.20	$ 16.41	**$ 14.49**	$ 13.94
Average	**$ 14.78**	$ 13.75	$ 11.03	**$ 14.36**	$ 12.41
Natural gas ($/Mcf) (1)					
North America	**$ 1.14**	$ 1.15	$ 1.14	**$ 1.18**	$ 1.16
North Sea	**$ 8.86**	$ 6.96	$ 5.38	**$ 6.66**	$ 3.56
Offshore Africa	**$ 5.76**	$ 3.37	$ 3.03	**$ 4.37**	$ 3.79
Average	**$ 1.17**	$ 1.19	$ 1.18	**$ 1.21**	$ 1.21
Average ($/BOE) (1)	**$ 11.91**	$ 11.42	$ 9.84	**$ 11.85**	$ 10.76

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and NGLs production expense for the nine months ended September 30, 2021 averaged $12.98 per bbl, an increase of 14% from $11.34 per bbl for the nine months ended September 30, 2020. North America crude oil and NGLs production expense for the third quarter of 2021 of $13.33 per bbl increased 36% from $9.80 per bbl for the third quarter of 2020 and increased 4% from $12.82 per bbl for the second quarter of 2021. The increase in crude oil and NGLs production expense per bbl for the nine months ended September 30, 2021 from the comparable period in 2020 primarily reflected an increase in energy costs in 2021. The increase in crude oil and NGLs production expense per bbl for the third quarter of 2021 from the comparable periods primarily reflected lower production volumes in the third quarter of 2021 and higher energy costs.

North America natural gas production expense for the nine months ended September 30, 2021 averaged $1.18 per Mcf, comparable with $1.16 per Mcf for the nine months ended September 30, 2020. North America natural gas production expense for the third quarter of 2021 of $1.14 per Mcf was comparable with $1.14 per Mcf for the third quarter of 2020 and $1.15 per Mcf for the second quarter of 2021, reflecting the Company's continuous focus on cost control.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2021 averaged $49.83 per bbl, an increase of 56% from $31.99 per bbl for the nine months ended September 30, 2020. North Sea crude oil production expense for the third quarter of 2021 of $55.90 per bbl increased 33% from $42.10 per bbl for the third quarter of 2020 and decreased 12% from $63.65 per bbl for the second quarter of 2021. The increase in crude oil production expense per bbl for the three and nine months ended September 30, 2021 from the comparable periods in 2020 primarily reflected lower volumes due to planned maintenance activities, on a relatively fixed cost base, together with higher energy costs. The decrease in crude oil production expense per bbl for the third quarter of 2021 from the second quarter of 2021 reflected the timing of liftings from various fields that have different cost structures. North Sea production expense also reflected fluctuations in the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the nine months ended September 30, 2021 averaged $14.49 per bbl, an increase of 4% from $13.94 per bbl for the nine months ended September 30, 2020. Offshore Africa crude oil production expense for the third quarter of 2021 of $14.53 per bbl decreased 11% from $16.41 per bbl for the third quarter of 2020 and increased 10% from $13.20 per bbl for the second quarter of 2021. The fluctuations in crude oil production expense per bbl from the comparable periods reflected the timing of liftings from various fields that have different cost structures. Offshore Africa production expense also reflected fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2021**	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
North America	**$ 881**	$ 881	$ 937	**$ 2,630**	$ 2,763
North Sea	**40**	19	41	**127**	216
Offshore Africa	**48**	44	68	**123**	136
Expense	**$ 969**	$ 944	$ 1,046	**$ 2,880**	$ 3,115
$/BOE (1)	**$ 13.70**	$ 13.57	$ 15.01	**$ 13.66**	$ 15.41

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, depreciation and amortization expense for the nine months ended September 30, 2021 of $13.66 per BOE decreased 11% from $15.41 per BOE for the nine months ended September 30, 2020. Depletion, depreciation and amortization expense for the third quarter of 2021 of $13.70 per BOE decreased 9% from $15.01 per BOE for the third quarter of 2020 and was comparable with $13.57 per BOE for the second quarter of 2021. The decrease in depletion, depreciation and amortization expense per BOE for the three and nine months ended September 30, 2021 from the comparable periods in 2020 primarily reflected lower depletion rates in the North America Exploration and Production segment.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2021**	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
North America	**$ 26**	$ 25	$ 23	**$ 76**	$ 73
North Sea	**6**	5	7	**16**	22
Offshore Africa	**1**	2	2	**4**	5
Expense	**$ 33**	$ 32	$ 32	**$ 96**	$ 100
$/BOE (1)	**$ 0.45**	$ 0.46	$ 0.47	**$ 0.45**	$ 0.50

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

Asset retirement obligation accretion expense for the nine months ended September 30, 2021 of $0.45 per BOE decreased 10% from $0.50 per BOE for the nine months ended September 30, 2020. Asset retirement obligation accretion expense for the third quarter of 2021 of $0.45 per BOE decreased 4% from $0.47 per BOE for the third quarter of 2020 and was comparable with $0.46 per BOE for the second quarter of 2021. Fluctuations in asset retirement obligation accretion expense on a per BOE basis primarily reflect fluctuating sales volumes.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. SCO production in the third quarter of 2021 of 468,126 bbl/d primarily reflected the completion of expansion activities at Scotford in the prior year and the completion of planned turnaround activities in the second quarter of 2021.

The Company incurred production costs, excluding natural gas costs, of $802 million ($18.63 per bbl) for the third quarter of 2021, a 22% decrease per bbl from the second quarter of 2021.

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

	Three Months Ended			Nine Months Ended	
($/bbl) [1]	**Sep 30 2021**	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
SCO realized sales price [2]	**$ 81.54**	$ 76.19	$ 48.92	**$ 74.00**	$ 42.40
Bitumen value for royalty purposes [3]	**$ 62.28**	$ 58.46	$ 36.26	**$ 55.54**	$ 22.77
Bitumen royalties [4]	**$ 8.21**	$ 5.92	$ 0.46	**$ 5.67**	$ 0.49
Transportation	**$ 1.14**	$ 1.26	$ 1.30	**$ 1.16**	$ 1.17

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending and feedstock costs.

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

(4) Calculated based on bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

The realized SCO sales price averaged $74.00 per bbl for the nine months ended September 30, 2021, an increase of 75% from $42.40 per bbl for the nine months ended September 30, 2020. The realized SCO sales price averaged $81.54 per bbl for the third quarter of 2021, an increase of 67% from $48.92 per bbl for the third quarter of 2020 and an increase of 7% from $76.19 per bbl for the second quarter of 2021. The increase in the realized SCO sales price for the three and nine months ended September 30, 2021 from the comparable periods primarily reflected increases in WTI benchmark pricing.

The increase in bitumen royalties per bbl for the three and nine months ended September 30, 2021 from the comparable periods primarily reflected the impact of higher prevailing bitumen pricing and AOSP reaching full payout.

Transportation expense averaged $1.16 per bbl for the nine months ended September 30, 2021, comparable with $1.17 per bbl for the nine months ended September 30, 2020. For the third quarter of 2021, transportation expense of $1.14 per bbl decreased 12% from $1.30 per bbl for the third quarter of 2020 and decreased 10% from $1.26 per bbl for the second quarter of 2021. The decrease in transportation expense per bbl for the third quarter of 2021 from the comparable periods primarily reflected the impact of higher sales volumes during the third quarter of 2021.

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 Company's unaudited interim consolidated financial statements.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2021**	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Production costs, excluding natural gas costs	**$ 802**	$ 799	$ 760	**$ 2,380**	$ 2,232
Natural gas costs	**53**	51	28	**163**	95
Production costs	**$ 855**	$ 850	$ 788	**$ 2,543**	$ 2,327

($/bbl) (1)	Three Months Ended **Sep 30 2021**	 Jun 30 2021	 Sep 30 2020	Nine Months Ended **Sep 30 2021**	 Sep 30 2020
Production costs, excluding natural gas costs	**$ 18.63**	$ 23.94	$ 22.96	**$ 20.05**	$ 19.71
Natural gas costs	**1.23**	1.52	0.85	**1.37**	0.84
Production costs	**$ 19.86**	$ 25.46	$ 23.81	**$ 21.42**	$ 20.55
Sales (bbl/d)	**467,772**	366,843	359,479	**434,848**	413,157

(1) Amounts expressed on a per unit basis are based on sales volumes.

Production costs for the nine months ended September 30, 2021 increased 4% to $21.42 per bbl from $20.55 per bbl for the nine months ended September 30, 2020. Production costs for the third quarter of 2021 averaged $19.86 per bbl, a decrease of 17% from $23.81 per bbl for the third quarter of 2020 and a decrease of 22% from $25.46 per bbl for the second quarter of 2021. The increase in production costs per bbl for the nine months ended September 30, 2021 from the comparable period in 2020 primarily reflected the impact of higher energy costs, including natural gas and diesel. The decrease in production costs per bbl for the third quarter of 2021 from the comparable periods primarily reflected the timing of planned turnaround activities. The Company continued to focus on cost control and efficiencies across the entire asset base.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended **Sep 30 2021**	 Jun 30 2021	 Sep 30 2020	Nine Months Ended **Sep 30 2021**	 Sep 30 2020
Expense	**$ 469**	$ 441	$ 414	**$ 1,360**	$ 1,305
$/bbl (1)	**$ 10.90**	$ 13.20	$ 12.51	**$ 11.45**	$ 11.53

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, depreciation and amortization expense for the nine months ended September 30, 2021 of $11.45 per bbl was comparable with $11.53 per bbl for the nine months ended September 30, 2020. Depletion, depreciation and amortization expense for the third quarter of 2021 of $10.90 per bbl decreased 13% from $12.51 per bbl for the third quarter of 2020, and decreased 17% from $13.20 per bbl for the second quarter of 2021. The decrease in depletion, depreciation and amortization on a per barrel basis for the third quarter of 2021 from the comparable periods primarily reflected the impact of higher sales volumes in the third quarter of 2021 and minor asset derecognitions in the comparable periods.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended **Sep 30 2021**	 Jun 30 2021	 Sep 30 2020	Nine Months Ended **Sep 30 2021**	 Sep 30 2020
Expense	**$ 14**	$ 14	$ 19	**$ 43**	$ 54
$/bbl (1)	**$ 0.33**	$ 0.43	$ 0.55	**$ 0.36**	$ 0.47

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

Asset retirement obligation accretion expense for the nine months ended September 30, 2021 of $0.36 per bbl decreased 23% from $0.47 per bbl for the nine months ended September 30, 2020. Asset retirement obligation accretion expense of $0.33 per bbl for the third quarter of 2021 decreased 40% from $0.55 per bbl for the third quarter of 2020 and decreased 23% from $0.43 per bbl for the second quarter of 2021. Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended Sep 30 2021	Jun 30 2021	Sep 30 2020	Nine Months Ended Sep 30 2021	Sep 30 2020
Product sales					
Midstream activities	**$ 21**	$ 21	$ 21	**$ 61**	$ 62
NWRP, refined product sales and other	**179**	171	78	**481**	103
Segmented revenue	**200**	192	99	**542**	165
Less:					
NWRP, refining toll	**46**	72	70	**176**	94
Midstream activities	**4**	7	4	**16**	15
Production expense	**50**	79	74	**192**	109
NWRP, transportation and feedstock costs	**146**	134	76	**385**	98
Depreciation	**4**	3	4	**11**	11
Income from NWRP	**—**	(400)	—	**(400)**	—
Segmented earnings (loss) before taxes	**$ —**	$ 376	$ (55)	**$ 354**	$ (53)

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 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. Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment. For the third quarter of 2021, production of ultra-low sulphur diesel and other refined products averaged 77,387 BOE/d (19,347 BOE/d to the Company), (three months ended September 30, 2020 – 52,678 BOE/d; 13,169 BOE/d to the Company), reflecting the 25% toll payer commitment.

On June 30, 2021, the equity partners together with the toll payers, agreed to optimize the structure of NWRP to better align the commercial interests of the equity partners and the toll payers (the "Optimization Transaction"). As a result, North West Refining Inc. transferred its entire 50% partnership interest in NWRP to APMC. The Company's 50% equity interest remained unchanged.

Under the Optimization Transaction, the original term of the processing agreements was extended by 10 years from 2048 to 2058. NWRP retired higher cost subordinated debt, which carried interest rates of prime plus 6%, with lower cost senior secured bonds at an average rate of approximately 2.55%, reducing interest costs to NWRP and associated tolls to the toll payers. As such, NWRP repaid the Company's and APMC's subordinated debt advances of $555 million each. In addition, the Company received a $400 million distribution from NWRP during the second quarter of 2021.

As at September 30, 2021, the cumulative unrecognized share of the equity loss from NWRP of $150 million and total partnership distributions in excess of the cumulative share of equity loss, was $550 million (December 31, 2020 – $153 million; September 30, 2020 – $159 million). For the three months ended September 30, 2021, unrecognized equity loss was $21 million, (nine months ended September 30, 2021 – unrecognized equity income of $3 million; three months ended September 30, 2020 – unrecognized equity income of $16 million; nine months ended September 30, 2020 – unrecognized equity loss of $100 million).

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended Sep 30 2021	Jun 30 2021	Sep 30 2020	Nine Months Ended Sep 30 2021	Sep 30 2020
Expense	**$ 87**	$ 87	$ 88	**$ 269**	$ 284
$/BOE (1)	**$ 0.77**	$ 0.84	$ 0.85	**$ 0.82**	$ 0.90

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for the nine months ended September 30, 2021 of $0.82 per BOE decreased 9% from $0.90 per BOE for the nine months ended September 30, 2020. Administration expense for the third quarter of 2021 of $0.77 per BOE decreased 9% from $0.85 per BOE for the third quarter of 2020 and decreased 8% from $0.84 per BOE for the second quarter of 2021. Administration expense per BOE decreased for the three and nine months ended September 30, 2021 from the comparable periods primarily due to higher sales volumes. The decrease in administration expense per BOE for the nine months ended September 30, 2021 from the comparable period also reflected higher overhead recoveries.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Sep 30 2021	Jun 30 2021	Sep 30 2020	Nine Months Ended Sep 30 2021	Sep 30 2020
Expense (recovery)	**$ 57**	$ 137	$ (5)	**$ 323**	$ (205)

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 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 $323 million share-based compensation expense for the nine months ended September 30, 2021, 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. Included within the share-based compensation expense for the nine months ended September 30, 2021 was an expense of $46 million related to PSUs granted to certain executive employees (September 30, 2020 – $4 million recovery).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Sep 30 2021	Jun 30 2021	Sep 30 2020	Nine Months Ended Sep 30 2021	Sep 30 2020
Expense, gross	**$ 178**	$ 177	$ 180	**$ 540**	$ 600
Less: capitalized interest	**—**	—	6	**—**	21
Expense, net	**$ 178**	$ 177	$ 174	**$ 540**	$ 579
$/BOE (1)	**$ 1.56**	$ 1.73	$ 1.69	**$ 1.64**	$ 1.84
Average effective interest rate	**3.6%**	3.5%	3.4%	**3.5%**	3.6%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Net interest and other financing expense per BOE for the nine months ended September 30, 2021 decreased 11% to $1.64 per BOE from $1.84 per BOE for the nine months ended September 30, 2020. Net interest and other financing expense per BOE for the third quarter of 2021 decreased 8% to $1.56 per BOE from $1.69 per BOE for the third quarter of 2020 and decreased 10% from $1.73 per BOE for the second quarter of 2021. The decrease in interest expense and other financing expense per BOE for the three and nine months ended September 30, 2021 from the comparable periods was primarily due to lower average debt levels in 2021, partially offset by lower interest income.

The Company's average effective interest rate for the third quarter of 2021 was comparable with the second quarter of 2021.

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 2021**	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Foreign currency contracts	**$ (18)**	$ 15	$ 20	**$ 12**	$ (9)
Natural gas financial instruments	**14**	3	5	**11**	18
Net realized (gain) loss	**(4)**	18	25	**23**	9
Foreign currency contracts	**(1)**	(4)	—	**(10)**	(9)
Natural gas financial instruments	**(18)**	14	(2)	**21**	(9)
Net unrealized (gain) loss	**(19)**	10	(2)	**11**	(18)
Net (gain) loss	**$ (23)**	$ 28	$ 23	**$ 34**	$ (9)

During the nine months ended September 30, 2021, net realized risk management losses were related to the settlement of foreign currency contracts and natural gas financial instruments. The Company recorded a net unrealized loss of $11 million ($6 million after-tax) on its risk management activities for the nine months ended September 30, 2021, including an unrealized gain of $19 million ($15 million after-tax) for the third quarter of 2021 (June 30, 2021 – unrealized loss of $10 million, $6 million after-tax; September 30, 2020 – unrealized gain of $2 million, $1 million after-tax).

Further details related to outstanding derivative financial instruments at September 30, 2021 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2021**	Jun 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Net realized loss (gain)	**$ 84**	$ 11	$ 16	**$ 105**	$ (180)
Net unrealized loss (gain)	**197**	(151)	(270)	**(126)**	418
Net loss (gain) [(1)]	**$ 281**	$ (140)	$ (254)	**$ (21)**	$ 238

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

The net realized foreign exchange loss for the nine months ended September 30, 2021 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$500 million of 3.45% debt securities. The net unrealized foreign exchange gain for the nine months ended September 30, 2021 was primarily related to the impact of the reversal of the net unrealized foreign exchange loss on the repayment of US$500 million of 3.45% debt securities. The US/Canadian dollar exchange rate at September 30, 2021 was US$0.7843 (June 30, 2021 – US$0.8062, September 30, 2020 – US$0.7505).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Sep 30 2021**	Jun 30 2021	Sep 30 2020	Nine Months Ended **Sep 30 2021**	Sep 30 2020
North America [1]	**$ 541**	$ 324	$ (59)	**$ 1,150**	$ (287)
North Sea	**4**	(5)	(14)	**10**	(4)
Offshore Africa	**7**	7	6	**18**	12
PRT [2] – North Sea	**(5)**	(12)	(17)	**(22)**	(17)
Other taxes	**4**	3	2	**9**	4
Current income tax expense (recovery)	**551**	317	(82)	**1,165**	(292)
Deferred income tax expense (recovery)	**56**	129	91	**206**	(156)
	$ 607	$ 446	$ 9	**$ 1,371**	$ (448)
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**22%**	24%	15%	**22%**	32%

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

(2) Petroleum Revenue Tax.

(3) Excludes the impact of current and deferred PRT and other current income tax.

The effective income tax rate for the three and nine months ended September 30, 2021 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 (loss).

The current corporate income tax and PRT in the North Sea for the three and nine months ended September 30, 2021 and the prior 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]

($ millions)	Three Months Ended Sep 30 2021	Three Months Ended Jun 30 2021	Three Months Ended Sep 30 2020	Nine Months Ended Sep 30 2021	Nine Months Ended Sep 30 2020
Exploration and Evaluation					
Net property dispositions	**$ (1)**	$ (4)	$ (12)	**$ (5)**	$ (30)
Net expenditures	**5**	1	1	**10**	27
Total Exploration and Evaluation	**4**	(3)	(11)	**5**	(3)
Property, Plant and Equipment					
Net property acquisitions	**131**	7	(1)	**139**	14
Well drilling, completion and equipping	**232**	224	80	**722**	314
Production and related facilities	**244**	186	157	**622**	449
Other	**12**	16	14	**41**	40
Total Property, Plant and Equipment	**619**	433	250	**1,524**	817
Total Exploration and Production	**623**	430	239	**1,529**	814
Oil Sands Mining and Upgrading					
Project costs	**69**	61	67	**171**	172
Sustaining capital	**233**	346	254	**765**	627
Turnaround costs	**19**	74	131	**122**	174
Other [2]	**3**	326	8	**330**	26
Total Oil Sands Mining and Upgrading	**324**	807	460	**1,388**	999
Midstream and Refining	**3**	1	1	**6**	4
Abandonments [3]	**54**	44	68	**165**	197
Head office	**7**	3	3	**16**	16
Total net capital expenditures	**$ 1,011**	$ 1,285	$ 771	**$ 3,104**	$ 2,030
By segment					
North America	**$ 564**	$ 378	$ 170	**$ 1,361**	$ 660
North Sea	**49**	44	45	**125**	88
Offshore Africa	**10**	8	24	**43**	66
Oil Sands Mining and Upgrading	**324**	807	460	**1,388**	999
Midstream and Refining	**3**	1	1	**6**	4
Abandonments [3]	**54**	44	68	**165**	197
Head office	**7**	3	3	**16**	16
Total	**$ 1,011**	$ 1,285	$ 771	**$ 3,104**	$ 2,030

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

(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table and are net of the impact of government grant income under the provincial well-site rehabilitation programs.

Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities

($ millions)	Three Months Ended **Sep 30 2021**	Jun 30 2021	Sep 30 2020	Nine Months Ended **Sep 30 2021**	Sep 30 2020
Cash flows used in investing activities	***$ 721***	*$ 719*	*$ 643*	***$ 2,088***	*$ 2,195*
Net change in non-cash working capital	***108***	*(33)*	*60*	***168***	*(362)*
Proceeds from investment	***128***	—	—	***128***	—
Repayment of NWRP subordinated debt advances	**—**	*555*	—	***555***	—
Abandonment expenditures (1)	***54***	*44*	*68*	***165***	*197*
Net capital expenditures	***$ 1,011***	*$ 1,285*	*$ 771*	***$ 3,104***	*$ 2,030*

(1) The Company excludes abandonment expenditures from "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" in the "Financial Highlights" section of this MD&A and are net of the impact of government grant income under the provincial well-site rehabilitation programs.

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, 2021 were $3,104 million compared with $2,030 million for the nine months ended September 30, 2020. Net capital expenditures for the third quarter of 2021 were $1,011 million compared with $771 million for the third quarter of 2020 and $1,285 million for the second quarter of 2021.

During the nine months ended September 30, 2021, the Company has completed three opportunistic acquisitions. The first two acquisitions consisted of natural gas assets located in the Montney region of British Columbia, with aggregate production of approximately 11,100 BOE/d, consisting of 63 MMcf/d and 600 bbl/d of NGLs, approximately 107,000 acres of Montney lands, and related processing infrastructure with approximately 140 MMcf/d of capacity. These two acquisitions build on the Company’s expansive natural gas operations in northeastern British Columbia, increasing the Company's total Montney lands to approximately 1.3 million acres. The third acquisition consisted of a net carried interest on an existing Canadian Natural oil sands lease, from which all of the Company's current Horizon volumes are derived. Total cash consideration paid for these acquisitions was approximately $450 million.

2021 Capital Budget

On December 9, 2020, the Company announced its 2021 capital budget targeted at approximately $3,205 million, of which $1,345 million was related to conventional and unconventional assets and $1,860 million was allocated to long-life low decline assets. On August 5, 2021, the 2021 capital budget was increased by $275 million to $3,480 million, excluding acquisitions. The increase included $120 million for conventional and unconventional assets, $110 million for long-life low decline assets, and $45 million for additional well abandonment activities.

The 2021 capital budget constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Drilling Activity [1]

(number of net wells)	Three Months Ended Sep 30 2021	Jun 30 2021	Sep 30 2020	Nine Months Ended Sep 30 2021	Sep 30 2020
Net successful natural gas wells	**9**	9	9	**40**	21
Net successful crude oil wells [2]	**56**	27	—	**127**	37
Dry wells	**1**	—	—	**1**	—
Stratigraphic test / service wells	**7**	1	1	**336**	372
Total	**73**	37	10	**504**	430
Success rate (excluding stratigraphic test / service wells)	**98%**	100%	100%	**99%**	100%

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

(2) Includes bitumen wells.

North America

During the third quarter of 2021, the Company targeted 9 net natural gas wells, 49 net primary heavy crude oil wells, and 6 net light crude oil wells.

North Sea

During the third quarter of 2021, the Company targeted 1.9 net light crude oil wells in the North Sea.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	Sep 30 2021	Jun 30 2021	Dec 31 2020	Sep 30 2020
Working capital [1]	**$ 423**	$ 723	$ 626	$ 707
Long-term debt [2] [3]	**$ 16,774**	$ 18,331	$ 21,453	$ 21,876
Less: cash and cash equivalents	**894**	168	184	175
Long-term debt, net	**$ 15,880**	$ 18,163	$ 21,269	$ 21,701
Share capital	**$ 9,857**	$ 9,863	$ 9,606	$ 9,522
Retained earnings	**25,632**	24,390	22,766	22,520
Accumulated other comprehensive income (loss)	**37**	(46)	8	124
Shareholders' equity	**$ 35,526**	$ 34,207	$ 32,380	$ 32,166
Debt to book capitalization [3] [4]	**30.9%**	34.7%	39.6%	40.3%
Debt to market capitalization [3] [5]	**22.5%**	25.4%	37.0%	46.3%
After-tax return on average common shareholders' equity [6]	**17.5%**	12.4%	(1.3)%	(1.8)%
After-tax return on average capital employed [3] [7]	**12.1%**	8.6%	0.2%	0.0%

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

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

(3) Long-term debt is stated at its carrying value, net of original issue discounts and premiums and transaction costs.

(4) Calculated as net current and long-term debt; divided by the book value of common shareholders' equity plus net current and long-term debt.

(5) Calculated as net current and long-term debt; divided by the market value of common shareholders' equity plus net current and long-term debt.

(6) Calculated as net earnings (loss) for the twelve month trailing period; as a percentage of average common shareholders' equity for the twelve month trailing period.

(7) Calculated as net earnings (loss) 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.

As at September 30, 2021, 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, 2020. 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.

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 first quarter of 2021, the $1,000 million non-revolving term credit facility, originally due February 2022, was extended to February 2023.
    - During the third quarter of 2021, the Company repaid $500 million of the $2,650 million non-revolving term credit facility, reducing the outstanding balance to $2,150 million. Subsequent to September 30, 2021, the Company repaid an additional $1,000 million on the facility, reducing the outstanding balance to $1,150 million.
    - During 2019, the Company entered into a $3,250 million non-revolving term credit facility with an original maturity of June 2022, to finance the acquisition of assets from Devon Canada Corporation. During the second quarter of 2021, the outstanding balance of $2,125 million was repaid and the facility was cancelled.
    - 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, replacing the Company's previous base shelf prospectus, which would have expired in August 2021. 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, replacing the Company's previous base shelf prospectus, which would have expired in August 2021. 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 2021, the Company early repaid US$500 million of 3.45% debt securities, originally due November 2021.
    - Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, US base rate or Canadian prime rate. As at September 30, 2021, the non-revolving term credit facilities were fully drawn.
    - Each of the $2,425 million revolving credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. 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, 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.

As at September 30, 2021, the Company had undrawn revolving bank credit facilities of $4,959 million. Including cash and cash equivalents and short-term investments, the Company had approximately $6,159 million in liquidity. Additionally, the Company had in place fully drawn term credit facilities of $3,150 million. The Company also has certain other dedicated credit facilities supporting letters of credit.

As at September 30, 2021, the Company had total US dollar denominated debt with a carrying amount of $13,444 million (US$10,545 million), before transaction costs and original issue discounts. This included $3,627 million (US$2,845 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$2,295 million). The fixed repayment amount of these hedging instruments is $3,560 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $67 million to $13,377 million as at September 30, 2021.

Net long-term debt was $15,880 million at September 30, 2021, resulting in a debt to book capitalization ratio of 30.9% (December 31, 2020 – 39.6%); this ratio is within 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 at September 30, 2021 are discussed in note 8 of the Company's unaudited interim consolidated 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, 2021, 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 at September 30, 2021 are discussed in note 15 of the Company's unaudited interim consolidated financial statements.

As at September 30, 2021, 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]	$ 1,000	$ 4,419	$ 3,167	$ 8,276
Other long-term liabilities [2]	$ 231	$ 180	$ 431	$ 851
Interest and other financing expense [3]	$ 676	$ 606	$ 1,511	$ 4,090

(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, $186 million; one to less than two years, $147 million; two to less than five years, $422 million; and thereafter, $851 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 at September 30, 2021.

Share Capital

As at September 30, 2021, there were 1,175,701,000 common shares outstanding (December 31, 2020 – 1,183,866,000 common shares) and 47,780,000 stock options outstanding. As at November 2, 2021, the Company had 1,176,819,000 common shares outstanding and 42,625,000 stock options outstanding.

On November 3, 2021, the Board of Directors approved an increase in the quarterly dividend to $0.5875 per common share, a 25% increase from the previous quarterly dividend, beginning with the dividend payable on January 5, 2022. On March 3, 2021, the Board of Directors approved an increase in the quarterly dividend to $0.47 per common share (previous quarterly dividend rate of $0.425 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 9, 2021, 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 59,278,474 common shares, over a 12-month period commencing March 11, 2021 and ending March 10, 2022.

For the nine months ended September 30, 2021, the Company purchased 17,624,400 common shares at a weighted average price of $42.14 per common share for a total cost of $743 million. Retained earnings were reduced by $597 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2021, the Company purchased 3,840,000 common shares at a weighted average price of $51.22 per common share for a total cost of $197 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, 2021:

($ millions)	Remaining 2021	2022	2023	2024	2025	Thereafter
Product transportation and processing (1)	$ 221	$ 851	$ 934	$ 853	$ 820	$ 10,478
North West Redwater Partnership service toll (2)	$ 31	$ 123	$ 123	$ 121	$ 119	$ 3,760
Offshore vessels and equipment	$ 19	$ 42	$ —	$ —	$ —	$ —
Field equipment and power	$ 9	$ 21	$ 21	$ 21	$ 21	$ 246
Other	$ 7	$ 21	$ 20	$ 21	$ 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 $1,499 million of interest payable over the 40-year tolling period.

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.

ACCOUNTING POLICIES

Regulatory Developments

On May 27, 2021, the Canadian Securities Administrators (CSA) announced the adoption of National Instrument 52-112 Non-GAAP and Other Financial Measures Disclosure ("NI 52-112") and related amendments. This National Instrument replaces the previous CSA staff notice on Non-GAAP Measures. NI 52-112 governs how entities present non-GAAP and other financial measures and ratios. The requirements will apply to the Company's MD&A and certain other disclosure documents for the three months and year ended December 31, 2021. The Company is in the process of assessing required changes to the MD&A and certain other disclosure documents.

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. For the three and nine months ended September 30, 2021, COVID-19 continued to have an impact on the global economy, including the oil and gas industry. Business conditions in the third quarter of 2021 continued to reflect the market uncertainty associated with COVID-19, with some improvements to global crude oil demand and supply conditions. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions, and judgements in the preparation of the unaudited interim consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. 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, 2020.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the nine months ended September 30, 2021 that have materially affected, or are reasonably likely to materially affect the Company’s ICFR. 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.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Sep 30 2021	Dec 31 2020
ASSETS			
Current assets			
Cash and cash equivalents		**$ 894**	$ 184
Accounts receivable		**3,176**	2,190
Current income taxes receivable		**—**	309
Inventory		**1,235**	1,060
Prepaids and other		**291**	231
Investments	6	**306**	305
Current portion of other long-term assets	7	**56**	82
		5,958	4,361
Exploration and evaluation assets	3	**2,398**	2,436
Property, plant and equipment	4	**64,785**	65,752
Lease assets	5	**1,548**	1,645
Other long-term assets	7	**602**	1,082
		$ 75,291	$ 75,276
LIABILITIES			
Current liabilities			
Accounts payable		**$ 989**	$ 667
Accrued liabilities		**2,863**	2,346
Current income taxes payable		**973**	—
Current portion of long-term debt	8	**1,000**	1,343
Current portion of other long-term liabilities	5,9	**710**	722
		6,535	5,078
Long-term debt	8	**15,774**	20,110
Other long-term liabilities	5,9	**7,564**	7,564
Deferred income taxes		**9,892**	10,144
		39,765	42,896
SHAREHOLDERS' EQUITY			
Share capital	11	**9,857**	9,606
Retained earnings		**25,632**	22,766
Accumulated other comprehensive income	12	**37**	8
		35,526	32,380
		$ 75,291	$ 75,276

Commitments and contingencies (note 16).

Approved by the Board of Directors on November 3, 2021.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Sep 30 2021	Three Months Ended Sep 30 2020	Nine Months Ended Sep 30 2021	Nine Months Ended Sep 30 2020
Product sales	17	**$ 8,521**	$ 4,676	**$ 22,664**	$ 12,272
Less: royalties		**(810)**	(172)	**(1,820)**	(397)
Revenue		**7,711**	4,504	**20,844**	11,875
Expenses					
Production		**1,762**	1,556	**5,283**	4,649
Transportation, blending and feedstock		**1,516**	989	**4,539**	3,180
Depletion, depreciation and amortization	4,5	**1,442**	1,464	**4,251**	4,431
Administration		**87**	88	**269**	284
Share-based compensation	9	**57**	(5)	**323**	(205)
Asset retirement obligation accretion	9	**47**	51	**139**	154
Interest and other financing expense		**178**	174	**540**	579
Risk management activities	15	**(23)**	23	**34**	(9)
Foreign exchange loss (gain)		**281**	(254)	**(21)**	238
Gain on acquisitions	4	**(478)**	—	**(478)**	—
Income from North West Redwater Partnership	7	**—**	—	**(400)**	—
Loss (gain) from investments	6	**33**	1	**(136)**	206
		4,902	4,087	**14,343**	13,507
Earnings (loss) before taxes		**2,809**	417	**6,501**	(1,632)
Current income tax expense (recovery)	10	**551**	(82)	**1,165**	(292)
Deferred income tax expense (recovery)	10	**56**	91	**206**	(156)
Net earnings (loss)		**$ 2,202**	$ 408	**$ 5,130**	$ (1,184)
Net earnings (loss) per common share					
Basic	14	**$ 1.87**	$ 0.35	**$ 4.33**	$ (1.00)
Diluted	14	**$ 1.86**	$ 0.35	**$ 4.32**	$ (1.00)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2021	Three Months Ended Sep 30 2020	Nine Months Ended Sep 30 2021	Nine Months Ended Sep 30 2020
Net earnings (loss)	**$ 2,202**	$ 408	**$ 5,130**	$ (1,184)
Items that may be reclassified subsequently to net earnings (loss)				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $1 million (2020 – $1 million) – three months ended; $3 million (2020 – $2 million) – nine months ended	**16**	(9)	**34**	17
Reclassification to net earnings (loss), net of taxes of $nil (2020 – $1 million) – three months ended; $1 million (2020 – $2 million) – nine months ended	**(3)**	(4)	**(8)**	(13)
	13	(13)	**26**	4
Foreign currency translation adjustment				
Translation of net investment	**70**	(61)	**3**	86
Other comprehensive income (loss), net of taxes	**83**	(74)	**29**	90
Comprehensive income (loss)	**$ 2,285**	$ 334	**$ 5,159**	$ (1,094)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended Sep 30 2021	Sep 30 2020
Share capital	11		
Balance – beginning of period		**$ 9,606**	$ 9,533
Issued upon exercise of stock options		**347**	36
Previously recognized liability on stock options exercised for common shares		**50**	9
Purchase of common shares under Normal Course Issuer Bid		**(146)**	(56)
Balance – end of period		**9,857**	9,522
Retained earnings			
Balance – beginning of period		**22,766**	25,424
Net earnings (loss)		**5,130**	(1,184)
Dividends on common shares	11	**(1,667)**	(1,505)
Purchase of common shares under Normal Course Issuer Bid	11	**(597)**	(215)
Balance – end of period		**25,632**	22,520
Accumulated other comprehensive income	12		
Balance – beginning of period		**8**	34
Other comprehensive income, net of taxes		**29**	90
Balance – end of period		**37**	124
Shareholders' equity		**$ 35,526**	$ 32,166

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Sep 30 2021**	Three Months Ended Sep 30 2020	Nine Months Ended **Sep 30 2021**	Nine Months Ended Sep 30 2020
Operating activities					
Net earnings (loss)		**$ 2,202**	$ 408	**$ 5,130**	$ (1,184)
Non-cash items					
Depletion, depreciation and amortization		**1,442**	1,464	**4,251**	4,431
Share-based compensation		**57**	(5)	**323**	(205)
Asset retirement obligation accretion		**47**	51	**139**	154
Unrealized risk management (gain) loss		**(19)**	(2)	**11**	(18)
Unrealized foreign exchange loss (gain)		**197**	(270)	**(126)**	418
Realized foreign exchange loss on repayment of US dollar debt securities	8	**118**	—	**118**	—
Realized foreign exchange gain on settlement of cross currency swaps		**—**	—	**—**	(166)
Gain on acquisitions	4	**(478)**	—	**(478)**	—
Loss (gain) from investments	6	**35**	3	**(129)**	218
Deferred income tax expense (recovery)		**56**	91	**206**	(156)
Other		**19**	26	**(8)**	(79)
Abandonment expenditures		**(77)**	(68)	**(215)**	(197)
Net change in non-cash working capital		**691**	372	**544**	228
Cash flows from operating activities		**4,290**	2,070	**9,766**	3,444
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net	8	**(1,184)**	68	**(4,172)**	901
Repayment of medium-term notes	8	**—**	(1,000)	**—**	(1,900)
(Repayment) issue of US dollar debt securities	8	**(628)**	—	**(628)**	1,481
Proceeds on settlement of cross currency swaps		**—**	—	**—**	166
Payment of lease liabilities	5,9	**(49)**	(52)	**(154)**	(178)
Issue of common shares on exercise of stock options		**83**	1	**347**	36
Dividends on common shares		**(558)**	(502)	**(1,618)**	(1,448)
Purchase of common shares under Normal Course Issuer Bid	11	**(507)**	—	**(743)**	(271)
Cash flows used in financing activities		**(2,843)**	(1,485)	**(6,968)**	(1,213)
Investing activities					
Net (expenditures) proceeds on exploration and evaluation assets	3,17	**(4)**	11	**(5)**	3
Net expenditures on property, plant and equipment	4,17	**(953)**	(714)	**(2,934)**	(1,836)
Proceeds from investment	6	**128**	—	**128**	—
Repayment of North West Redwater Partnership subordinated debt advances	7	**—**	—	**555**	—
Net change in non-cash working capital		**108**	60	**168**	(362)
Cash flows used in investing activities		**(721)**	(643)	**(2,088)**	(2,195)
Increase (decrease) in cash and cash equivalents		**726**	(58)	**710**	36
Cash and cash equivalents – beginning of period		**168**	233	**184**	139
Cash and cash equivalents – end of period		**$ 894**	$ 175	**$ 894**	$ 175
Interest paid on long-term debt, net		**$ 196**	$ 211	**$ 550**	$ 598
Income taxes received, net		**$ (11)**	$ (101)	**$ (94)**	$ (29)

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, 2020, 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, 2020.

Critical Accounting Estimates and Judgements

For the three and nine months ended September 30, 2021, the novel coronavirus ("COVID-19") continued to have an impact on the global economy, including the oil and gas industry. Business conditions in the third quarter of 2021 continued to reflect the market uncertainty associated with COVID-19, with some improvements to global crude oil demand and supply conditions. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions and judgements in the preparation of the unaudited interim consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Actual results may differ from estimated amounts, and those differences may be material.

2. CHANGES IN ACCOUNTING POLICIES

In August 2020, the IASB issued Interest Rate Benchmark Reform (Phase 2) in response to the Financial Stability Board's mandated reforms to InterBank Offered Rates ("IBORs"), with financial regulators proposing that current IBOR benchmark rates be replaced by a number of new local currency denominated alternative benchmark rates. The Company retrospectively adopted the amendments on January 1, 2021. Adoption of these amendments did not have a significant impact on the Company's 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, 2020	$ 2,101	$ —	$ 83	$ 252	$ 2,436
Additions	**16**	**—**	**6**	**—**	**22**
Transfers to property, plant and equipment	**(60)**	**—**	**—**	**—**	**(60)**
At September 30, 2021	**$ 2,057**	**$ —**	**$ 89**	**$ 252**	**$ 2,398**

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, 2020	$ 73,997	$ 7,283	$ 3,963	$ 45,710	$ 457	$ 485	$ 131,895
Additions	**1,491**	**119**	**39**	**1,388**	**6**	**16**	**3,059**
Transfers from E&E assets	**60**	**—**	**—**	**—**	**—**	**—**	**60**
Derecognitions and other (1)	**(285)**	**—**	**—**	**(322)**	**—**	**—**	**(607)**
Foreign exchange adjustments and other	**—**	**(1)**	**(1)**	**—**	**—**	**—**	**(2)**
At September 30, 2021	**$ 75,263**	**$ 7,401**	**$ 4,001**	**$ 46,776**	**$ 463**	**$ 501**	**$ 134,405**
Accumulated depletion and depreciation							
At December 31, 2020	$ 49,641	$ 5,853	$ 2,822	$ 7,289	$ 168	$ 370	$ 66,143
Expense	**2,555**	**118**	**103**	**1,280**	**11**	**18**	**4,085**
Derecognitions and other (1)	**(285)**	**—**	**—**	**(322)**	**—**	**—**	**(607)**
Foreign exchange adjustments and other	**19**	**(4)**	**(13)**	**(3)**	**—**	**—**	**(1)**
At September 30, 2021	**$ 51,930**	**$ 5,967**	**$ 2,912**	**$ 8,244**	**$ 179**	**$ 388**	**$ 69,620**
Net book value							
- at September 30, 2021	**$ 23,333**	**$ 1,434**	**$ 1,089**	**$ 38,532**	**$ 284**	**$ 113**	**$ 64,785**
- at December 31, 2020	$ 24,356	$ 1,430	$ 1,141	$ 38,421	$ 289	$ 115	$ 65,752

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

On July 29, 2021, the Company completed two acquisitions, including property, plant and equipment assets of $257 million and exploration and evaluation assets of $13 million, for cash consideration of $131 million. In connection with the acquisitions, the Company assumed asset retirement obligations of $58 million, other liabilities of $65 million, and recognized a deferred tax asset of $462 million. A gain of $478 million was recognized as a result of the acquisitions, representing the excess of the fair value of the net assets acquired compared with the total purchase consideration. These transactions were accounted for using the acquisition method of accounting. The acquired business consists of a 100% interest in certain natural gas properties located in the Montney region of British Columbia and related processing infrastructure. The allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities acquired as of the acquisition date, and may be subject to change based on the receipt of new information.

5. LEASES

Lease assets

		Product transportation and storage		Field equipment and power		Offshore vessels and equipment		Office leases and other		Total
At December 31, 2020	$	1,038	$	379	$	128	$	100	$	1,645
Additions		**47**		**19**		**—**		**4**		**70**
Depreciation		**(84)**		**(43)**		**(23)**		**(16)**		**(166)**
Foreign exchange adjustments and other		**(1)**		**—**		**1**		**(1)**		**(1)**
At September 30, 2021	**$**	**1,000**	**$**	**355**	**$**	**106**	**$**	**87**	**$**	**1,548**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at September 30, 2021 were as follows:

		Sep 30 2021		Dec 31 2020
Lease liabilities	**$**	**1,606**	$	1,690
Less: current portion		**186**		189
	$	**1,420**	$	1,501

Total cash outflows for leases for the three months ended September 30, 2021, including payments related to short-term leases not reported as lease assets, were $257 million (three months ended September 30, 2020 – $213 million; nine months ended September 30, 2021 – $831 million; nine months ended September 30, 2020 – $762 million). Interest expense on leases for the three months ended September 30, 2021 was $15 million (three months ended September 30, 2020 – $16 million; nine months ended September 30, 2021 – $47 million; nine months ended September 30, 2020 – $50 million).

6. INVESTMENTS

As at September 30, 2021, the Company had the following investments:

		Sep 30 2021		Dec 31 2020
Investment in PrairieSky Royalty Ltd.	**$**	**306**	$	228
Investment in Inter Pipeline Ltd.		**—**		77
	$	**306**	$	305

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

	Three Months Ended				Nine Months Ended			
		Sep 30 2021		Sep 30 2020		**Sep 30 2021**		Sep 30 2020
Loss (gain) from investments	**$**	**35**	$	3	**$**	**(129)**	$	218
Dividend income		**(2)**		(2)		**(7)**		(12)
	$	**33**	$	1	**$**	**(136)**	$	206

The Company's investment in PrairieSky Royalty Ltd. ("PrairieSky") 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, 2021, the Company's investment in PrairieSky was classified as a current asset. The investment in PrairieSky consists of approximately 22.6 million common shares. As at September 30, 2021, the market price per common share was $13.51 (December 31, 2020 – $10.09; September 30, 2020 – $8.31).

During the third quarter of 2021, in accordance with a third-party offer to purchase, the Company elected to take total cash proceeds of $128 million, or $20.00 per common share, in exchange for its 6.4 million common share investment in Inter Pipeline Ltd.

7. OTHER LONG-TERM ASSETS

		Sep 30 2021		Dec 31 2020
North West Redwater Partnership ("NWRP")	**$**	**—**	$	555
Prepaid cost of service tolls		**158**		162
Risk management (note 15)		**178**		136
Long-term inventory		**128**		121
Other		**194**		190
		658		1,164
Less: current portion		**56**		82
	$	**602**	$	1,082

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. Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 17).

On June 30, 2021, the equity partners together with the toll payers, agreed to optimize the structure of NWRP to better align the commercial interests of the equity partners and the toll payers (the "Optimization Transaction"). As a result, North West Refining Inc. transferred its entire 50% partnership interest in NWRP to APMC. The Company's 50% equity interest remained unchanged.

Under the Optimization Transaction, the original term of the processing agreements was extended by 10 years from 2048 to 2058. NWRP retired higher cost subordinated debt, which carried interest rates of prime plus 6%, with lower cost senior secured bonds at an average rate of approximately 2.55%, reducing interest costs to NWRP and associated tolls to the toll payers. As such, NWRP repaid the Company's and APMC's subordinated debt advances of $555 million each. In addition, the Company received a $400 million distribution from NWRP during the second quarter of 2021.

To facilitate the Optimization Transaction, NWRP issued $500 million of 1.20% series L senior secured bonds due December 2023, $500 million of 2.00% series M senior secured bonds due December 2026, $1,000 million of 2.80% series N senior secured bonds due June 2031, and $600 million of 3.75% series O senior secured bonds due June 2051. Additionally, NWRP's existing $3,500 million syndicated credit facility was amended. The $2,000 million revolving credit facility was extended by three years to June 2024, and the $1,500 million non-revolving credit facility was reduced by $500 million to $1,000 million and extended by two years to June 2023.

As at September 30, 2021, the cumulative unrecognized share of the equity loss from NWRP of $150 million and total partnership distributions in excess of the cumulative share of equity loss, was $550 million (December 31, 2020 – $153 million; September 30, 2020 – $159 million). For the three months ended September 30, 2021, unrecognized equity loss was $21 million, (nine months ended September 30, 2021 – unrecognized equity income of $3 million; three months ended September 30, 2020 – unrecognized equity income of $16 million; nine months ended September 30, 2020 – unrecognized equity loss of $100 million).

8. LONG-TERM DEBT

	Sep 30 2021	Dec 31 2020
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 218**	$ 1,614
Medium-term notes	**3,200**	3,200
	3,418	4,814
US dollar denominated debt, unsecured		
Bank credit facilities (September 30, 2021 – US$2,295 million; December 31, 2020 – US$3,953 million)	**2,926**	5,041
Commercial paper (September 30, 2021 – US$nil; December 31, 2020 – US$426 million)	**—**	544
US dollar debt securities (September 30, 2021 – US$8,250 million; December 31, 2020 – US$8,750 million)	**10,518**	11,161
	13,444	16,746
Long-term debt before transaction costs and original issue discounts, net	**16,862**	21,560
Less: original issue discounts, net (1)	**16**	18
transaction costs (1) (2)	**72**	89
	16,774	21,453
Less: current portion of commercial paper	**—**	544
current portion of other long-term debt (1) (2)	**1,000**	799
	$ 15,774	$ 20,110

(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, 2021, the Company had undrawn revolving bank credit facilities of $4,959 million. Additionally, the Company had in place fully drawn term credit facilities of $3,150 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 $2,425 million revolving syndicated credit facility maturing June 2022;
- a $1,000 million non-revolving term credit facility maturing February 2023;
- a $2,150 million non-revolving term credit facility maturing February 2023;
- a $2,425 million revolving syndicated credit facility maturing June 2023; and
- a £5 million demand credit facility related to the Company's North Sea operations.

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

During the first quarter of 2021, the $1,000 million non-revolving term credit facility, originally due February 2022, was extended to February 2023.

During the third quarter of 2021, the Company repaid $500 million of the $2,650 million non-revolving term credit facility, reducing the outstanding balance to $2,150 million. Subsequent to September 30, 2021, the Company repaid an additional $1,000 million on the facility, reducing the outstanding balance to $1,150 million.

During 2019, the Company entered into a $3,250 million non-revolving term credit facility with an original maturity of June 2022, to finance the acquisition of assets from Devon Canada Corporation. During the second quarter of 2021, the outstanding balance of $2,125 million was repaid and the facility was cancelled.

The revolving syndicated credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. 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, 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.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at September 30, 2021 was 1.2% (September 30, 2020 – 1.3%), and on total long-term debt outstanding for the nine months ended September 30, 2021 was 3.4% (September 30, 2020 – 3.6%).

As at September 30, 2021, letters of credit and guarantees aggregating to $463 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, replacing the Company's previous base shelf prospectus, which would have expired in August 2021. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US Dollar Debt Securities

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, replacing the Company's previous base shelf prospectus, which would have expired in August 2021. 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 2021, the Company early repaid US$500 million of 3.45% debt securities, originally due November 2021.

9. OTHER LONG-TERM LIABILITIES

	Sep 30 2021	Dec 31 2020
Asset retirement obligations	**$ 5,840**	$ 5,861
Lease liabilities (note 5)	**1,606**	1,690
Share-based compensation	**396**	160
Risk management (note 15)	**39**	160
Transportation and processing contracts	**267**	270
Other [1]	**126**	145
	8,274	8,286
Less: current portion	**710**	722
	$ 7,564	$ 7,564

(1) Includes $48 million related to the acquisition of the Joslyn oil sands project in 2018, payable in annual installments of $25 million over the next two years.

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 3.7% (December 31, 2020 – 3.7%) and inflation rates of up to 2% (December 31, 2020 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Sep 30 2021	Dec 31 2020
Balance – beginning of period	**$ 5,861**	$ 5,771
Liabilities incurred	**4**	5
Liabilities acquired, net	**58**	13
Liabilities settled	**(215)**	(249)
Asset retirement obligation accretion	**139**	205
Revision of cost and timing estimates	**(6)**	(134)
Change in discount rates	**—**	253
Foreign exchange adjustments	**(1)**	(3)
Balance – end of period	**5,840**	5,861
Less: current portion	**116**	184
	$ 5,724	$ 5,677

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 2021	Dec 31 2020
Balance – beginning of period	**$ 160**	$ 297
Share-based compensation expense (recovery)	**323**	(82)
Cash payment for stock options surrendered and PSUs vested	**(40)**	(39)
Transferred to common shares	**(50)**	(21)
Other	**3**	5
Balance – end of period	**396**	160
Less: current portion	**270**	119
	$ 126	$ 41

Included within share-based compensation liability as at September 30, 2021 was $58 million related to PSUs granted to certain executive employees (December 31, 2020 – $49 million).

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Nine Months Ended	
Expense (recovery)	**Sep 30 2021**	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Current corporate income tax – North America	**$ 541**	$ (59)	**$ 1,150**	$ (287)
Current corporate income tax – North Sea	**4**	(14)	**10**	(4)
Current corporate income tax – Offshore Africa	**7**	6	**18**	12
Current PRT [(1)] – North Sea	**(5)**	(17)	**(22)**	(17)
Other taxes	**4**	2	**9**	4
Current income tax	**551**	(82)	**1,165**	(292)
Deferred income tax	**56**	91	**206**	(156)
Income tax	**$ 607**	$ 9	**$ 1,371**	$ (448)

(1) Petroleum Revenue Tax

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Nine Months Ended Sep 30, 2021	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,183,866**	**$ 9,606**
Issued upon exercise of stock options	**9,459**	**347**
Previously recognized liability on stock options exercised for common shares	**—**	**50**
Purchase of common shares under Normal Course Issuer Bid	**(17,624)**	**(146)**
Balance – end of period	**1,175,701**	**$ 9,857**

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 3, 2021, the Board of Directors approved an increase in the quarterly dividend to $0.5875 per common share, a 25% increase from the previous quarterly dividend, beginning with the dividend payable on January 5, 2022. On March 3, 2021, the Board of Directors declared a quarterly dividend of $0.47 per common share, an increase from the previous quarterly dividend of $0.425 per common share.

Normal Course Issuer Bid

On March 9, 2021, 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 59,278,474 common shares, over a 12-month period commencing March 11, 2021 and ending March 10, 2022.

For the nine months ended September 30, 2021, the Company purchased 17,624,400 common shares at a weighted average price of $42.14 per common share for a total cost of $743 million. Retained earnings were reduced by $597 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2021, the Company purchased 3,840,000 common shares at a weighted average price of $51.22 per common share for a total cost of $197 million.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding at September 30, 2021:

	Nine Months Ended Sep 30, 2021		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**48,656**	**$**	**37.53**
Granted	**11,913**	**$**	**33.34**
Exercised for common shares	**(9,459)**	**$**	**36.76**
Surrendered for cash settlement	**(539)**	**$**	**37.61**
Forfeited	**(2,791)**	**$**	**35.80**
Outstanding – end of period	**47,780**	**$**	**36.74**
Exercisable – end of period	**12,476**	**$**	**40.86**

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 2021		Sep 30 2020
Derivative financial instruments designated as cash flow hedges	**$**	**95**	$	75
Foreign currency translation adjustment		**(58)**		49
	$	**37**	$	124

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 net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. 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. At September 30, 2021, the ratio was within the target range at 30.9%.

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

		Sep 30 2021		Dec 31 2020
Long-term debt, net [1]	**$**	**15,880**	$	21,269
Total shareholders' equity	**$**	**35,526**	$	32,380
Debt to book capitalization		**30.9%**		39.6%

(1) Includes the current portion of long-term debt, net of cash and cash equivalents.

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%. At September 30, 2021, the Company was in compliance with this covenant.

14. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Weighted average common shares outstanding – basic (thousands of shares)	**1,179,603**	1,181,046	**1,183,463**	1,181,701
Effect of dilutive stock options (thousands of shares)	**5,356**	441	**3,689**	—
Weighted average common shares outstanding – diluted (thousands of shares)	**1,184,959**	1,181,487	**1,187,152**	1,181,701
Net earnings (loss)	**$ 2,202**	$ 408	**$ 5,130**	$ (1,184)
Net earnings (loss) per common share – basic	**$ 1.87**	$ 0.35	**$ 4.33**	$ (1.00)
– diluted	**$ 1.86**	$ 0.35	**$ 4.32**	$ (1.00)

15. FINANCIAL INSTRUMENTS

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

	Sep 30, 2021				
Asset (liability)	**Financial assets at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 3,176**	**$ —**	**$ —**	**$ —**	**$ 3,176**
Investments	**—**	**306**	**—**	**—**	**306**
Other long-term assets	**—**	**3**	**175**	**—**	**178**
Accounts payable	**—**	**—**	**—**	**(989)**	**(989)**
Accrued liabilities	**—**	**—**	**—**	**(2,863)**	**(2,863)**
Other long-term liabilities (1)	**—**	**(39)**	**—**	**(1,654)**	**(1,693)**
Long-term debt (2)	**—**	**—**	**—**	**(16,774)**	**(16,774)**
	$ 3,176	**$ 270**	**$ 175**	**$ (22,280)**	**$ (18,659)**

	Dec 31, 2020				
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 2,190	$ —	$ —	$ —	$ 2,190
Investments	—	305	—	—	305
Other long-term assets	555	—	136	—	691
Accounts payable	—	—	—	(667)	(667)
Accrued liabilities	—	—	—	(2,346)	(2,346)
Other long-term liabilities (1)	—	(52)	(108)	(1,762)	(1,922)
Long-term debt (2)	—	—	—	(21,453)	(21,453)
	$ 2,745	$ 253	$ 28	$ (26,228)	$ (23,202)

(1) Includes $1,606 million of lease liabilities (December 31, 2020 – $1,690 million) and $48 million of deferred purchase consideration payable over the next two years (December 31, 2020 – $72 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, 2021			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3** (4)
Investments (3)	**$ 306**	**$ 306**	**$ —**	**$ —**
Other long-term assets	**$ 178**	**$ —**	**$ 178**	**$ —**
Other long-term liabilities	**$ (87)**	**$ —**	**$ (39)**	**$ (48)**
Fixed rate long-term debt (6) (7)	**$ (13,630)**	**$ (15,721)**	**$ —**	**$ —**

	Dec 31, 2020			
	Carrying amount	Fair value		
Asset (liability) (1) (2)		Level 1	Level 2	Level 3 (4) (5)
Investments (3)	$ 305	$ 305	$ —	$ —
Other long-term assets	$ 691	$ —	$ 136	$ 555
Other long-term liabilities	$ (232)	$ —	$ (160)	$ (72)
Fixed rate long-term debt (6) (7)	$ (14,254)	$ (16,598)	$ —	$ —

(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 NWRP subordinated debt was based on the present value of future cash receipts.

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

(7) 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 2021**	Dec 31 2020
Derivatives held for trading		
Natural gas fixed price swaps	**$ (27)**	$ (5)
Natural gas basis swaps	**(12)**	(40)
Foreign currency forward contracts	**3**	(7)
Cash flow hedges		
Foreign currency forward contracts	**10**	(108)
Cross currency swaps	**165**	136
	$ 139	$ (24)
Included within:		
Current portion of other long-term assets	**$ 19**	$ 5
Current portion of other long-term liabilities	**(20)**	(131)
Other long-term assets	**159**	131
Other long-term liabilities	**(19)**	(29)
	$ 139	$ (24)

For the nine months ended September 30, 2021, the ineffectiveness arising from cash flow hedges was $nil (year ended December 31, 2020 – loss of $1 million).

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 2021**	Dec 31 2020
Balance – beginning of period	**$ (24)**	$ 178
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	**16**	(32)
Foreign exchange	**119**	(168)
Other comprehensive income (loss)	**28**	(2)
Balance – end of period	**139**	(24)
Less: current portion	**(1)**	(126)
	$ 140	$ 102

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2021	Sep 30 2020	**Sep 30 2021**	Sep 30 2020
Net realized risk management (gain) loss	**$ (4)**	$ 25	**$ 23**	$ 9
Net unrealized risk management (gain) loss	**(19)**	(2)	**11**	(18)
	$ (23)	$ 23	**$ 34**	$ (9)

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 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.

At September 30, 2021, the Company had the following derivative financial instruments outstanding:

	Remaining term		Weighted average volume	Weighted average price	Index
Natural Gas					
Fixed price swap	Oct 2021 –	Dec 2021	26,616 GJ/d	$2.02/GJ	AECO
	Oct 2021 –	Dec 2021	15,054 MMBtu/d	US$2.42/MMBtu	DAWN
	Oct 2021 –	Dec 2021	13,370 MMBtu/d	US$2.51/MMBtu	NYMEX
	Oct 2021 –	Dec 2021	15,000 MMBtu/d	US$2.62/MMBtu	SUMAS
Basis swap	Oct 2021 –	Dec 2023	55,535 MMBtu/d	US$1.24/MMBtu	AECO
	Jan 2024 –	Dec 2025	20,000 MMBtu/d	US$0.97/MMBtu	AECO
	Oct 2021 –	Dec 2021	20,000 MMBtu/d	US$0.09/MMBtu	DAWN

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. At September 30, 2021, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into 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. The cross currency swap contract requires the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based.

At September 30, 2021, the Company had the following cross currency swap contract outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swap	Oct 2021	–	Mar 2038	US$550	1.170	6.25 %	5.76 %

The cross currency swap derivative financial instrument was designated as a hedge at September 30, 2021 and was classified as a cash flow hedge.

In addition to the cross currency swap contract noted above, at September 30, 2021, the Company had US$2,872 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$2,295 million designated as cash flow hedges.

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. At September 30, 2021, 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. At September 30, 2021, the Company had net risk management assets of $174 million with specific counterparties related to derivative financial instruments (December 31, 2020 – $129 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, 2021, 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	$ 989	$ —	$ —	$ —
Accrued liabilities	$ 2,863	$ —	$ —	$ —
Long-term debt (1)	$ 1,000	$ 4,419	$ 3,167	$ 8,276
Other long-term liabilities (2)	$ 231	$ 180	$ 431	$ 851
Interest and other financing expense (3)	$ 676	$ 606	$ 1,511	$ 4,090

(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, $186 million; one to less than two years, $147 million; two to less than five years, $422 million; and thereafter, $851 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 at September 30, 2021.

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, 2021:

	Remaining 2021	2022	2023	2024	2025	Thereafter
Product transportation and processing (1)	$ 221	$ 851	$ 934	$ 853	$ 820	$ 10,478
North West Redwater Partnership service toll (2)	$ 31	$ 123	$ 123	$ 121	$ 119	$ 3,760
Offshore vessels and equipment	$ 19	$ 42	$ —	$ —	$ —	$ —
Field equipment and power	$ 9	$ 21	$ 21	$ 21	$ 21	$ 246
Other	$ 7	$ 21	$ 20	$ 21	$ 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 $1,499 million of interest payable over the 40-year tolling period (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)	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Segmented product sales																
Crude oil and NGLs	**3,506**	2,282	**10,047**	5,106	**141**	81	**410**	313	**163**	122	**381**	228	**3,810**	2,485	**10,838**	5,647
Natural gas	**644**	277	**1,583**	808	**1**	1	**3**	11	**5**	12	**20**	32	**650**	290	**1,606**	851
Other income and revenue [(1)]	**28**	17	**81**	28	**—**	—	**—**	3	**3**	19	**6**	22	**31**	36	**87**	53
Total segmented product sales	**4,178**	2,576	**11,711**	5,942	**142**	82	**413**	327	**171**	153	**407**	282	**4,491**	2,811	**12,531**	6,551
Less: royalties	**(448)**	(151)	**(1,128)**	(330)	**—**	—	**(1)**	(1)	**(8)**	(6)	**(18)**	(11)	**(456)**	(157)	**(1,147)**	(342)
Segmented revenue	**3,730**	2,425	**10,583**	5,612	**142**	82	**412**	326	**163**	147	**389**	271	**4,035**	2,654	**11,384**	6,209
Segmented expenses																
Production	**728**	583	**2,169**	1,877	**85**	61	**253**	222	**30**	41	**77**	76	**843**	685	**2,499**	2,175
Transportation, blending and feedstock	**1,023**	751	**3,313**	2,367	**1**	2	**5**	13	**1**	1	**1**	1	**1,025**	754	**3,319**	2,381
Depletion, depreciation and amortization	**881**	937	**2,630**	2,763	**40**	41	**127**	216	**48**	68	**123**	136	**969**	1,046	**2,880**	3,115
Asset retirement obligation accretion	**26**	23	**76**	73	**6**	7	**16**	22	**1**	2	**4**	5	**33**	32	**96**	100
Risk management activities (commodity derivatives)	**(4)**	3	**32**	9	**—**	—	**—**	—	**—**	—	**—**	—	**(4)**	3	**32**	9
Gain on acquisitions	**(478)**	—	**(478)**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(478)**	—	**(478)**	—
Income from North West Redwater Partnership	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**2,176**	2,297	**7,742**	7,089	**132**	111	**401**	473	**80**	112	**205**	218	**2,388**	2,520	**8,348**	7,780
Segmented earnings (loss) before the following	**1,554**	128	**2,841**	(1,477)	**10**	(29)	**11**	(147)	**83**	35	**184**	53	**1,647**	134	**3,036**	(1,571)
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange loss (gain)																
Loss (gain) from investments																
Total non–segmented expenses																
Earnings (loss) before taxes																
Current income tax expense (recovery)																
Deferred income tax expense (recovery)																
Net earnings (loss)																

(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	
	2021	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Segmented product sales																
Crude oil and NGLs [2]	**3,848**	1,764	**9,625**	5,311	**21**	21	**61**	62	**(72)**	(68)	**(247)**	(33)	**7,607**	4,202	**20,277**	10,987
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**44**	48	**152**	131	**694**	338	**1,758**	982
Other income and revenue [1]	**15**	25	**55**	125	**179**	78	**481**	103	**(5)**	(3)	**6**	22	**220**	136	**629**	303
Total segmented product sales	**3,863**	1,789	**9,680**	5,436	**200**	99	**542**	165	**(33)**	(23)	**(89)**	120	**8,521**	4,676	**22,664**	12,272
Less: royalties	**(354)**	(15)	**(673)**	(55)	**—**	—	**—**	—	**—**	—	**—**	—	**(810)**	(172)	**(1,820)**	(397)
Segmented revenue	**3,509**	1,774	**9,007**	5,381	**200**	99	**542**	165	**(33)**	(23)	**(89)**	120	**7,711**	4,504	**20,844**	11,875
Segmented expenses																
Production	**855**	788	**2,543**	2,327	**50**	74	**192**	109	**14**	9	**49**	38	**1,762**	1,556	**5,283**	4,649
Transportation, blending and feedstock [2]	**387**	188	**978**	641	**146**	76	**385**	98	**(42)**	(29)	**(143)**	60	**1,516**	989	**4,539**	3,180
Depletion, depreciation and amortization	**469**	414	**1,360**	1,305	**4**	4	**11**	11	**—**	—	**—**	—	**1,442**	1,464	**4,251**	4,431
Asset retirement obligation accretion	**14**	19	**43**	54	**—**	—	**—**	—	**—**	—	**—**	—	**47**	51	**139**	154
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(4)**	3	**32**	9
Gain on acquisitions	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(478)**	—	**(478)**	—
Income from North West Redwater Partnership	**—**	—	**—**	—	**—**	—	**(400)**	—	**—**	—	**—**	—	**—**	—	**(400)**	—
Total segmented expenses	**1,725**	1,409	**4,924**	4,327	**200**	154	**188**	218	**(28)**	(20)	**(94)**	98	**4,285**	4,063	**13,366**	12,423
Segmented earnings (loss) before the following	**1,784**	365	**4,083**	1,054	**—**	(55)	**354**	(53)	**(5)**	(3)	**5**	22	**3,426**	441	**7,478**	(548)
Non–segmented expenses																
Administration													**87**	88	**269**	284
Share-based compensation													**57**	(5)	**323**	(205)
Interest and other financing expense													**178**	174	**540**	579
Risk management activities (other)													**(19)**	20	**2**	(18)
Foreign exchange loss (gain)													**281**	(254)	**(21)**	238
Loss (gain) from investments													**33**	1	**(136)**	206
Total non-segmented expenses													**617**	24	**977**	1,084
Earnings (loss) before taxes													**2,809**	417	**6,501**	(1,632)
Current income tax expense (recovery)													**551**	(82)	**1,165**	(292)
Deferred income tax expense (recovery)													**56**	91	**206**	(156)
Net earnings (loss)													**2,202**	408	**5,130**	(1,184)

(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, 2021			Sep 30, 2020		
	Net expenditures (proceeds)	**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	**$ (1)**	**$ (43)**	**$ (44)**	$ (5)	$ (93)	$ (98)
Offshore Africa	**6**	**—**	**6**	2	—	2
	5	**(43)**	**(38)**	(3)	(93)	(96)
Property, plant and equipment						
Exploration and Production						
North America	**1,362**	**(96)**	**1,266**	665	(1,070)	(405)
North Sea	**125**	**(6)**	**119**	88	(114)	(26)
Offshore Africa	**37**	**2**	**39**	64	(29)	35
	1,524	**(100)**	**1,424**	817	(1,213)	(396)
Oil Sands Mining and Upgrading [3]	**1,388**	**(322)**	**1,066**	999	(690)	309
Midstream and Refining	**6**	**—**	**6**	4	—	4
Head office	**16**	**—**	**16**	16	—	16
	2,934	**(422)**	**2,512**	1,836	(1,903)	(67)
	$ 2,939	**$ (465)**	**$ 2,474**	$ 1,833	$ (1,996)	$ (163)

(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, capitalized interest and share-based compensation.

Segmented Assets

	Sep 30 2021	Dec 31 2020
Exploration and Production		
North America	**$ 28,946**	$ 29,094
North Sea	**1,544**	1,624
Offshore Africa	**1,356**	1,407
Other	**93**	81
Oil Sands Mining and Upgrading	**42,204**	41,567
Midstream and Refining	**960**	1,301
Head office	**188**	202
	$ 75,291	$ 75,276

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, 2021:	
Interest coverage (times)	
Net earnings (1)	11.1x
Adjusted funds flow (2)	18.1x

(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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Vice-President and Managing Director, International

Barry Duncan
Vice-President, Finance, International

Stock Listing

Toronto Stock Exchange
Trading Symbol - CNQ

New York Stock Exchange
Trading Symbol - CNQ

Registrar and Transfer Agent

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