FOURTH QUARTER REPORT

YEAR ENDED DECEMBER 31, 2021 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2021 FOURTH QUARTER AND YEAR END RESULTS

Commenting on the Company's 2021 results, Tim McKay, President of Canadian Natural, stated "Our unique and diverse asset base, combined with our track record of operational excellence delivered by our dedicated teams, achieved record average production volumes in 2021 of approximately 1,235 MBOE/d, representing an increase of 6% or approximately 71 MBOE/d over 2020 levels. During Q4/21, daily production volumes averaged a record 1,314 MBOE/d, including 1,004 Mbbl/d of liquids, primarily driven by strong quarterly production volumes from oil sands mining and thermal in situ. Our strong operational results during 2021 delivered robust annual adjusted funds flow of approximately $13.7 billion, which after capital expenditures of approximately $3.5 billion, excluding acquisitions, and dividends of approximately $2.2 billion, resulted in annual free cash flow of approximately $8.0 billion.

One of Canadian Natural's key strengths is the diversity of our world class assets. Strategically assembled and developed over several decades, our top tier assets have a low decline rate as well as low maintenance capital relative to the size and quality of our reserves, which affords us significant flexibility when balancing our four pillars of capital allocation to maximize shareholder value. Canadian Natural continues to deliver strong finding, development and acquisition ("FD&A") costs and reserves replacement ratios in 2021. Canadian Natural's total proved reserves increased 6% to 12.813 billion BOE, replacing 2021 production by 257% and resulting in a reserves life index of approximately 30 years. Total proved FD&A costs, including changes in future development costs, were $5.88/BOE in 2021.

Environmental, Social and Governance ("ESG") remains a priority for us as evidenced by our ongoing investment into new technology and innovation options designed to improve our environmental performance and reduce our environmental footprint. Canadian Natural aligns its environmental reporting with recommendations from the Task Force on Climate-related Financial Disclosures and the reporting framework from the Sustainability Accounting Standards Board. Canadian Natural has been producing its sustainability report, the Stewardship Report to Stakeholders, since 2004 to report on our ongoing commitment to environmental performance, social responsibility and continuous improvement. This report provides a performance overview across the full range of Canadian Natural’s operations in Western Canada, the UK portion of the North Sea and Offshore Africa. Canadian Natural targets to publish its 2021 Stewardship Report to Stakeholders in Q3/22 including third-party independent “reasonable assurance” on scope 1 and 2 emissions (including methane emissions) and “limited assurance” on scope 3 emissions. Additionally, Canadian Natural will continue to outline its pathway to lower carbon emissions across its asset base and its journey to achieve its goal of net zero greenhouse gas ("GHG") emissions in the oil sands. The report will display how Canadian Natural leverages technology and innovation to reduce its environmental footprint while ensuring safe, reliable, effective and efficient operations."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "The strength and sustainability of our business model was evident during 2021, with strong net earnings of approximately $7.7 billion ($6.49 per share) and adjusted funds flow of approximately $13.7 billion ($11.63 per share). We prudently balanced our four pillars of capital allocation throughout 2021 to maximize value for our shareholders and drive increasing returns on capital employed. Our large diversified portfolio of assets, underpinned by long life low decline assets which generate significant and sustainable free cash flow, allowed us in 2021 to enhance returns to shareholders through increased dividends and share repurchases, while reducing debt much faster than originally targeted. In 2021, we reduced net debt, inclusive of our recent opportunistic acquisition of Storm Resources Ltd. ("Storm") which closed in Q4/21, by approximately $7.3 billion when compared to year end 2020. Effective July 1, 2021, Canadian Natural enhanced its free cash flow allocation policy that states when net debt levels are below $15 billion, the Company will target to allocate 50% of free cash flow to share repurchases and 50% of free cash flow to the balance sheet. To the extent net debt is below $15 billion, such amount will be made available for strategic growth / acquisition opportunities. As year end 2021 net debt levels were approximately $14 billion, Canadian Natural is targeting in 2022 to allocate 50% of free cash flow to the balance sheet, less any strategic growth capital / acquisitions, and 50% of free cash flow to share repurchases.

Throughout 2021, we significantly increased returns to shareholders. We announced two dividend increases for a combined increase of 38% to $2.35 per share annually, which marked 2021 as the 21st consecutive year of dividend increases by Canadian Natural. Direct returns to shareholders in 2021 totaled approximately $3.8 billion, comprised of our sustainable and growing dividend of approximately $2.2 billion and share repurchases throughout the year which totaled approximately $1.6 billion, as well as indirect returns to shareholders through net debt reduction of approximately $7.3 billion.

Subsequent to quarter end, up to and including March 2, 2022 the Company has returned approximately $680 million to shareholders through the repurchase and cancellation of 10.5 million common shares and the Board of Directors have approved the renewal and increase of the Company's Normal Course Issuer Bid ("NCIB"). The approval states that during the 12 month period commencing March 11, 2022 and ending March 10, 2023, the Company can repurchase for cancellation up to 10% of the public float, subject to TSX approval.

Additionally, the Board of Directors has approved a 28% increase to our quarterly dividend to $0.75 per share, up from $0.5875 per share, continuing the Company’s leading track record of 22 consecutive years of dividend increases with a significant compound annual growth rate of 22% over that period of time.

This increase in the quarterly dividend demonstrates the confidence that the Board of Directors has in the Company’s world class assets and its ability to generate significant and sustainable free cash flow. Our asset base is underpinned by top tier, long life low decline assets, a strong balance sheet and effective and efficient operations that drive an industry leading WTI break-even in the mid-US$30s per barrel, which covers our base maintenance capital requirements and the increased dividend commitment, maximizing value for our shareholders."

HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Dec 31 2021**	Three Months Ended Sep 30 2021	Three Months Ended Dec 31 2020	Year Ended **Dec 31 2021**	Year Ended Dec 31 2020
Net earnings (loss)	**$ 2,534**	$ 2,202	$ 749	**$ 7,664**	$ (435)
Per common share – basic	**$ 2.16**	$ 1.87	$ 0.63	**$ 6.49**	$ (0.37)
– diluted	**$ 2.14**	$ 1.86	$ 0.63	**$ 6.46**	$ (0.37)
Adjusted net earnings (loss) from operations (1)	**$ 2,626**	$ 2,095	$ 176	**$ 7,420**	$ (756)
Per common share – basic (2)	**$ 2.24**	$ 1.78	$ 0.15	**$ 6.28**	$ (0.64)
– diluted (2)	**$ 2.21**	$ 1.77	$ 0.15	**$ 6.25**	$ (0.64)
Cash flows from operating activities	**$ 4,712**	$ 4,290	$ 1,270	**$ 14,478**	$ 4,714
Adjusted funds flow (1)	**$ 4,338**	$ 3,634	$ 1,708	**$ 13,733**	$ 5,200
Per common share – basic (2)	**$ 3.69**	$ 3.08	$ 1.45	**$ 11.63**	$ 4.40
– diluted (2)	**$ 3.66**	$ 3.07	$ 1.44	**$ 11.57**	$ 4.40
Cash flows used in investing activities	**$ 1,615**	$ 721	$ 624	**$ 3,703**	$ 2,819
Net capital expenditures, excluding net acquisition costs (1)	**$ 837**	$ 881	$ 655	**$ 3,483**	$ 2,701
Net capital expenditures, including net acquisition costs (1)	**$ 1,804**	$ 1,011	$ 1,176	**$ 4,908**	$ 3,206
Daily production, before royalties					
Natural gas (MMcf/d)	**1,857**	1,708	1,644	**1,695**	1,477
Crude oil and NGLs (bbl/d)	**1,004,425**	952,839	927,190	**952,404**	917,958
Equivalent production (BOE/d) (3)	**1,313,900**	1,237,503	1,201,198	**1,234,906**	1,164,136

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this interim report and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2021, dated March 2, 2022.

(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this interim report and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2021, dated March 2, 2022.

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

ANNUAL HIGHLIGHTS

- Canadian Natural delivered net earnings of approximately $7.7 billion and adjusted net earnings from operations of approximately $7.4 billion in 2021.
- Cash flows from operating activities were approximately $14.5 billion in 2021.
- Canadian Natural generated strong annual adjusted funds flow of approximately $13.7 billion in 2021, an increase of approximately $8.5 billion from 2020 levels.
- The strength of the Company's 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.
  - The strength of our effective and efficient operations and our high quality, long life low decline asset base, the Company generated annual free cash flow(1) of approximately $8.0 billion after dividend payments of approximately $2.2 billion and net capital expenditures of approximately $3.5 billion (excluding acquisitions).
  - Direct returns to shareholders in 2021 were strong, totaling approximately $3.8 billion, comprised of approximately $2.2 billion of dividends and approximately $1.6 billion of share repurchases.
    - Canadian Natural increased its sustainable and growing dividend twice in 2021 for a total combined increase of 38% to $2.35 per share annually, marking 2021 as the 21st consecutive year of dividend increases.

  - ◦ The Company repurchased a total of 33,644,400 common shares for cancellation at a weighted average price of $46.98 per share during 2021 for a total of approximately $1.6 billion.
- • Indirect returns to shareholders in 2021 included net debt reduction of approximately $7.3 billion, resulting in year end 2021 net debt of approximately $14.0 billion.

▪ Effective July 1, 2021, Canadian Natural enhanced its free cash flow allocation policy that states when net debt[1] levels are below $15 billion, the Company will target to allocate 50% of free cash flow to share repurchases and 50% of free cash flow to the balance sheet. To the extent net debt is below $15 billion, such amount will be made available for strategic growth / acquisition opportunities. As year end 2021 net debt levels were approximately $14.0 billion (inclusive of the recent opportunistic acquisition of Storm which closed in Q4/21), Canadian Natural is targeting in 2022 to allocate 50% of free cash flow to the balance sheet, less any strategic growth capital / acquisitions, and 50% of free cash flow to share repurchases.

- • Subsequent to quarter end the Board of Directors has approved a 28% increase to our quarterly dividend to $0.75 per share, up from $0.5875 per share, payable on April 5, 2022. The increased dividend demonstrates the confidence that the Board of Directors has in the sustainability of our business model, the strength of our balance sheet and the Company's long life low decline asset base. This is supported by industry leading effective and efficient operations, resulting in a low break-even[2], including base maintenance capital requirements and the increased dividend commitment.
  - ◦ Year to date the Company has returned approximately $680 million to shareholders through the repurchase and cancellation of 10.5 million common shares, up to and including March 2, 2022.
  - ◦ The Board of Directors have approved the renewal and increase of the Company's NCIB. The approval states that during the 12 month period commencing March 11, 2022 and ending March 10, 2023, Canadian Natural can repurchase for cancellation up to 10% of the public float, subject to TSX approval.

▪ During 2021, the Company executed on a number of strategic initiatives to further strengthen Canadian Natural's financial flexibility.

- • Canadian Natural significantly strengthened its balance sheet, reducing 2021 year end net debt compared to 2020 year end net debt levels by approximately $7.3 billion.
- • Canadian Natural had undrawn bank credit facilities of approximately $6.1 billion available at year end 2021. Including cash and cash equivalents and short-term investments, the Company had significant liquidity[1] of approximately $7.2 billion.
- • Significant debt repayments, including the early repayment of public debt, strengthened liquidity in 2021. The Company also increased and extended the terms on certain credit facilities and filed Canadian and US base shelf prospectuses providing the Company with different liquidity options.

▪ In 2021, the Company achieved record annual production volumes of 1,234,906 BOE/d, an increase of 6% over 2020 levels. The increase was primarily the result of strong operational performance with several production volume records achieved across the asset base in 2021.

- • Record annual average corporate liquids production of 952,404 bbl/d was achieved in 2021, an increase of 4% over 2020 levels. The increase in 2021 was primarily as a result of record annual production volumes over the Oil Sands Mining and Upgrading segment, strong drilling results in North American E&P assets as well as record thermal in situ production volumes.
  - ◦ The Company's world class Oil Sands Mining and Upgrading assets averaged record annual production of 448,133 bbl/d of Synthetic Crude Oil ("SCO"), an increase of 7% over 2020 levels. The increase over 2020 levels was primarily as a result of high utilization rates and the execution of operational enhancements throughout the year.
  - ◦ Canadian Natural's North America E&P assets produced record annual liquids volumes averaging 472,621 bbl/d in 2021, an increase of 3% over 2020 levels. The increase was primarily the result of strong drilling results and increased thermal in situ production.
    - – The Company's thermal in situ assets achieved record production in 2021, averaging 259,284 bbl/d, an increase of 4% over the previous record levels achieved in 2020. The increase in production volumes in 2021 was primarily due to successful development activity and higher utilization at Jackfish.

- Opportunistic acquisitions completed in Q4/20 and in 2021 combined with successful drilling resulted in robust corporate annual natural gas production averaging 1,695 MMcf/d in 2021, an increase of 15% over 2020 levels.

- The Company's 2022 capital budget is targeting base capital(3) of approximately $3.6 billion that delivers targeted production of approximately 1,270,000 BOE/d to 1,320,000 BOE/d, with disciplined year over year near-term growth of approximately 60,000 BOE/d derived primarily from conventional E&P operations.
  - Strategic growth capital(3) in 2022 of approximately $0.7 billion will be allocated to our long life low decline assets, which targets to add incremental annual production starting in 2023 and beyond, resulting in targeted total production growth of approximately 63,000 bbl/d by 2025.

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this interim report and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2021, dated March 2, 2022.

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

(3) Forward looking non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this interim report and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2021, dated March 2, 2022.

QUARTERLY HIGHLIGHTS

- Net earnings of $2,534 million and adjusted net earnings from operations of $2,626 million were realized in Q4/21, significant increases over Q4/20 net earnings of $749 million and adjusted net earnings from operations of $176 million, primarily as a result of higher realized pricing and effective and efficient operations.
- Cash flows from operating activities were $4,712 million in Q4/21, an increase over $1,270 million in Q4/20.
- Canadian Natural generated strong quarterly adjusted funds flow of $4,338 million in Q4/21, a significant increase over Q3/21 levels of $3,634 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 free cash flow of $2,949 million in Q4/21, after dividend payments of $552 million and net capital expenditures of $837 million, excluding acquisitions.
- Direct returns to shareholders during Q4/21 were significant, as Canadian Natural returned approximately $1,390 million by way of dividends totaling $552 million and share repurchases totaling $838 million.
  - Share repurchases for cancellation during Q4/21 totaled 16,020,000 shares at a weighted average price of $52.31 per share.
- Indirect returns to shareholders during Q4/21 included a significant net debt reduction of approximately $1,930 million from Q3/21 levels.
- In Q4/21, the Company continued its focus on safe, effective and efficient operations, driving record average quarterly production volumes of 1,313,900 BOE/d, increases of 9% and 6% over Q4/20 and Q3/21 levels respectively.
  - Record quarterly liquids production volumes averaged 1,004,425 bbl/d in Q4/21, increases of 8% and 5% over Q4/20 and Q3/21 levels respectively, primarily due to Canadian Natural's effective and efficient operations contributing to record Oil Sands Mining and Upgrading volumes, record thermal in situ volumes and strong light crude oil and NGL volumes.
  - The Company delivered record average natural gas production of approximately 1,857 MMcf/d in Q4/21, an increase of 9% over Q3/21 levels. The increase from Q3/21 levels primarily reflects strong drilling results and production volumes from acquisitions, partially offset by natural field declines.
    - Corporate natural gas operating costs(1) in Q4/21 averaged $1.12/Mcf, a decrease of 4% from Q3/21 levels primarily due to higher production volumes and the Company's strong focus on cost control.
- Canadian Natural's North America E&P liquids production, including thermal in situ, averaged 478,738 bbl/d during Q4/21, comparable to Q4/20 levels and an increase of 5% over Q3/21 levels.
  - Canadian Natural's thermal in situ production averaged 263,110 bbl/d in Q4/21, comparable to Q4/20 levels and a 6% increase over Q3/21 levels. The increase in thermal in situ production during Q4/21 compared to Q3/21 was primarily due to the successful completion of planned turnaround activities at Jackfish during Q3/21.

- The Company's world class Oil Sands Mining and Upgrading assets achieved record average quarterly production of 493,406 bbl/d of SCO in Q4/21, increases of 18% and 5% over Q4/20 and Q3/21 levels respectively. Top tier operational performance in Q4/21 was due to the Company's continuous focus on safe, effective and efficient operations.
  - Operating costs from the Company's Oil Sands Mining and Upgrading assets were strong and remain top tier averaging $19.55/bbl (US$15.52/bbl) of SCO during Q4/21, decreases of 3% and 2% from Q4/20 and Q3/21 levels respectively. Lower operating costs in Q4/21 were primarily due to high reliability and the Company's strong focus on cost control.
  - Absolute operating costs from the Company's Oil Sands Mining and Upgrading assets, excluding the impact of higher natural gas prices, were approximately $796 million in Q4/21, a decrease of approximately $6 million compared to Q3/21 levels.

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

RESERVES UPDATE

A key differentiator for Canadian Natural is the strength, diversity and balance of our world class, top tier reserves. Strategically assembled and developed over several decades, these assets have a low decline as well as low maintenance capital relative to the size and quality of the reserves. The low maintenance capital requirements of our reserves affords the Company significant flexibility when balancing our four pillars of capital allocation to maximize shareholder value.

- The Company's reserves were evaluated and reviewed by Independent Qualified Reserves Evaluators. The following highlights are based on the Company's reserves using forecast prices and costs at December 31, 2021 (all reserves values are Company Gross unless stated otherwise).
- Total proved reserves increased 6% to 12.813 billion BOE, with reserves additions and revisions of 1.158 billion BOE. Total proved plus probable reserves increased 6% to 16.950 billion BOE, with reserves additions and revisions of 1.476 billion BOE.
  - The strength and depth of the Company's assets are evident as approximately 77% of total proved reserves are long life low decline reserves. This results in a total proved BOE reserves life index(1) of approximately 30 years and a total proved plus probable BOE reserves life index of approximately 40 years.
    - Additionally, high value, zero decline SCO is approximately 55% of total proved reserves with a reserve life index of approximately 45 years.
- In 2021, Canadian Natural continued its track record of top tier finding and development costs:
  - FD&A(1) costs, excluding changes in Future Development Cost ("FDC"), are $4.01/BOE for total proved reserves and $3.15/BOE for total proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $5.88/BOE for total proved reserves and $5.49/BOE for total proved plus probable reserves.
- Total proved reserves additions and revisions replaced 2021 production by 257%. Total proved plus probable reserves additions and revisions replaced 2021 production by 328%.
- Proved developed producing reserves additions and revisions are 703 million BOE, replacing 2021 production by 156%. The proved developed producing BOE reserves life index is approximately 21 years.
- The net present value of future net revenues, before income tax, discounted at 10%, is approximately $86.9 billion for proved developed producing reserves, approximately $120.3 billion for total proved reserves, and approximately $145.9 billion for total proved plus probable reserves.

(1) Supplementary financial measure. Refer to the "2021 year end Reserves" section of this interim report.

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 80% of total liquids production in 2021, 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	Year Ended Dec 31			
	2021		2020	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**154**	**149**	48	42
Natural gas	**62**	**49**	34	30
Dry	**1**	**1**	—	—
Subtotal	**217**	**199**	82	72
Stratigraphic test / service wells	**485**	**393**	427	372
Total	**702**	**592**	509	444
Success rate (excluding stratigraphic test / service wells)		**99%**		100%

- The Company's total crude oil and natural gas drilling program of 199 net wells for the twelve months ended December 31, 2021, excluding stratigraphic/service wells, represents an increase of 127 net wells from the 12 month period in 2020 and is consistent with the 2021 capital budget.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Crude oil and NGLs production (bbl/d)	**215,628**	206,775	209,710	**213,337**	211,472
Net wells targeting crude oil	**20**	55	5	**136**	35
Net successful wells drilled	**20**	54	5	**135**	35
Success rate	**100%**	98%	100%	**99%**	100%

- Canadian Natural's North America E&P crude oil and NGL production volumes, excluding thermal in situ, averaged 213,337 bbl/d in 2021, comparable to 2020 levels.
  - Primary heavy crude oil production averaged 64,366 bbl/d in 2021, an 8% decrease from 2020 levels.

- ◦ Operating costs in the Company's primary heavy crude oil operations averaged $19.37/bbl (US$15.46/bbl) in 2021, an increase of 10% compared to 2020 levels primarily due to higher energy costs.
- ◦ At the Company's Clearwater play at Smith, the 12 net horizontal multilateral wells brought on-stream in 2021 continue to perform well, with current production rates totaling over 3,200 bbl/d.
  - – Based on the success of our Smith development to date, the Company has commenced a two rig program targeting 41 net horizontal wells as part of the 2022 capital budget.

- Pelican Lake production in 2021 averaged 54,390 bbl/d, a decrease of 4% from 2020 levels. The production decrease reflects the low decline nature of this long life asset and the continued success of the Company's world class polymer flood.
  - ◦ Operating costs in 2021 at Pelican Lake of $6.75/bbl (US$5.39/bbl) increased 12% over 2020 levels. The operating cost increase from 2020 levels was primarily due to increased energy costs.
- North America light crude oil and NGL production averaged 94,581 bbl/d in 2021, an increase of 12% over 2020 levels. The increase from 2020 was primarily due to strong drilling results.
  - ◦ Operating costs in the Company's North America light crude oil and NGL areas averaged $15.28/bbl (US$12.19/bbl) in 2021, an increase of 5% over 2020 levels. The increase in operating costs in 2021 over 2020 was primarily the result of increased energy costs.
  - ◦ The Company delivered top tier execution and results at the Company's high value Montney light crude oil development at Wembley in 2021.
    - – As budgeted, a total of 18 net wells were brought onstream in 2021.
    - – 2021 exit production rates were strong at approximately 11,000 bbl/d of liquids and 35 MMcf/d of natural gas, representing an increase over budget of approximately 2,500 bbl/d of liquids and approximately 7 MMcf/d of natural gas.
    - – Based on the success of the 2021 development program at Wembley, Canadian Natural targets to complete 15 net wells in Wembley as part of the 2022 capital budget and targets to maintain its processing facilities at full capacity in 2022.

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Bitumen production (bbl/d)	**263,110**	248,113	266,179	**259,284**	248,971
Net wells targeting bitumen	**1**	—	—	**8**	6
Net successful wells drilled	**1**	—	—	**8**	6
Success rate	**100%**	—%	—%	**100%**	100%

- ▪ The Company's thermal in situ assets achieved record production in 2021, averaging 259,284 bbl/d, an increase of 4% over the previous record levels achieved in 2020. The increase in production volumes in 2021 was primarily due to successful development activity and higher utilization at Jackfish.
  - Thermal in situ assets operating costs averaged $12.14/bbl (US$9.69/bbl) in 2021, an increase of 29% over 2020 levels. The increase in operating costs from 2020 was primarily due to increased energy costs.
- ▪ As part of the 2022 capital budget, Canadian Natural's mid- and long-term strategic growth capital within its long life low decline thermal in situ assets includes the following:
  - The addition of 3 pads at Kirby and 2 pads at Jackfish, targeting on stream production volumes in mid-2023 with a targeted average capital efficiency(1) of approximately $8,000/bbl/d.
  - The construction of an additional SAGD pad as well as 2 CSS pads at Primrose with targeted on stream production volumes in mid-2023 and a targeted average capital efficiency of approximately $10,000/bbl/d.

(1) Supplementary financial measure. Refer to the "Non-GAAP and Other Financial Measures" section of this interim report.

- 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 GHG intensity and realize high solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
  - Canadian Natural's second pilot commenced in October 2021 in the steam flood area of Primrose and consists of 9 net wells, 5 producers and 4 injectors. The Company targets to operate this second pilot for two years with targeted SOR and GHG intensity reductions of 40% to 45% and solvent recoveries of greater than 70%.
  - Canadian Natural is progressing with engineering and design of a commercial scale solvent SAGD pad development at Kirby North and targets to commence solvent injection in early 2024.

North America Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Natural gas production (MMcf/d)	**1,841**	1,698	1,623	**1,680**	1,450
Net wells targeting natural gas	**9**	9	9	**49**	30
Net successful wells drilled	**9**	9	9	**49**	30
Success rate	**100%**	100%	100%	**100%**	100%

- North America natural gas production was strong in 2021, averaging approximately 1,680 MMcf/d, an increase of 16% over 2020 levels. The increase over 2020 was primarily the result of strong drilling results and production acquired in Q4/20.
  - North America natural gas operating costs in 2021 averaged $1.15/Mcf, comparable with 2020 levels.
- In 2021, at the Company's liquids-rich Montney area, excess facility capacity was utilized through its drill-to-fill strategy, adding low cost high value liquids rich natural gas production volumes.
  - At Septimus, strong results from a 5 well pad completed in June 2021 brought the facility to full capacity. Operational optimization combined with high plant reliability resulted in average production of approximately 145 MMcf/d in 2021.
    - Operating costs at Septimus remained strong in 2021, averaging $0.29/Mcfe, a decrease of 3% from 2020 levels. The decrease in operating costs was primarily the result of the Company's drill-to-fill strategy and maximizing operational and cost efficiencies.
- Canadian Natural completed the opportunistic acquisition of Storm in mid-December 2021 and targets to drill 14 net wells on these assets as part of the 2022 capital budget.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Crude oil production (bbl/d)					
North Sea	**17,860**	16,294	17,057	**17,633**	23,142
Offshore Africa	**14,421**	13,531	17,155	**14,017**	17,022
Natural gas production (MMcf/d)					
North Sea	**3**	2	4	**3**	12
Offshore Africa	**13**	8	17	**12**	15
Net wells targeting crude oil	**1.0**	1.9	—	**5.9**	1.0
Net successful wells drilled	**1.0**	1.9	—	**5.9**	1.0
Success rate	**100%**	100%	—%	**100%**	100%

- International E&P crude oil production volumes averaged 31,650 bbl/d in 2021, a decrease of 21% from 2020 levels. Lower production from prior periods primarily reflected maintenance activities in previous periods and natural field declines.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Synthetic crude oil production (bbl/d) (1)(2)	**493,406**	468,126	417,089	**448,133**	417,351

(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 delivered record annual average production of 448,133 bbl/d of SCO in 2021, an increase of 7% over 2020 levels. Strong 2021 production performance was primarily due to the Company's focus on effective and efficient operations.
  - Through Canadian Natural's culture of continuous improvement, the Company's world class Oil Sands Mining and Upgrading assets produced strong and consistent production volumes during 2021, including record production volumes of 493,406 bbl/d during Q4/21. Strong annual production in 2021 was primarily due to higher reliability across the Oil Sands Mining and Upgrading asset base combined with processing expansion work at the Scotford upgrader completed in 2020.
  - Operating costs were strong and remain top tier, averaging $20.91/bbl (US$16.68/bbl) of SCO during 2021, an increase of just 2% over 2020 levels. Canadian Natural's strong operational performance and focus on cost control significantly offset higher energy costs in the year, including a 52% increase in per barrel natural gas costs compared to 2020.
  - As previously announced, the Company's targeted turnaround schedules for its Oil Sands Mining and Upgrading operations in 2022 include:
    - A planned turnaround at Horizon beginning in May 2022 targeting a full plant outage for approximately 32 days with an impact of approximately 23,000 bbl/d to 2022 annual production.
    - A planned major turnaround at the non-operated Scotford Upgrader targeting to begin March 15, 2022 for a period of approximately 65 days with a net impact of approximately 12,000 bbl/d to 2022 annual production.
  - In lead up to the annual planned major turnaround at the non-operated Scotford Upgrader, the upgrader experienced production restrictions in January and February, impacting net Q1/22 quarterly production volumes by approximately 31,000 bbl/d. The Company's 2022 annual production target range remains unchanged.
  - Strategic growth capital being allocated at Horizon in 2022 to advance the reliability enhancement project which is targeted to extend the major maintenance cycle from once per year to once every second year increasing the capacity of zero decline, high value production by approximately 5,000 bbl/d of SCO in 2023, increasing to approximately 14,000 bbl/d of SCO in 2025.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 30 2020
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) [1]	**$ 77.17**	$ 70.55	$ 42.67	**$ 67.96**	$ 39.40
WCS heavy differential as a percentage of WTI (%) [2]	**19%**	17%	22%	**19%**	36%
SCO price (US$/bbl)	**$ 75.39**	$ 68.98	$ 39.69	**$ 66.36**	$ 36.26
Condensate benchmark pricing (US$/bbl)	**$ 79.10**	$ 69.22	$ 42.54	**$ 68.24**	$ 36.97
Average realized pricing before risk management (C$/bbl) [3][4]	**$ 72.81**	$ 68.06	$ 40.56	**$ 63.71**	$ 31.90
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 4.67**	$ 3.36	$ 2.62	**$ 3.38**	$ 2.12
Average realized pricing before risk management (C$/Mcf) [4]	**$ 5.35**	$ 4.13	$ 2.94	**$ 4.07**	$ 2.40

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

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

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

(4) Refer to the "Non-GAAP and Other Financial Measures" section of this interim report and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2021, dated March 2, 2022.

- Crude oil prices continued to improve in 2021 with WTI averaging US$67.96/bbl, an increase of 72% from 2020 levels. The increase in WTI pricing in 2021 from 2020 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 March 2, 2022 for crude oil, annual WTI pricing of US$93.39/bbl is currently 37% higher than 2021 levels.
- Natural gas prices continue to improve year over year with AECO averaging $3.38/GJ in 2021, an increase of 59% from 2020 natural gas pricing levels. The increase in natural gas prices from the comparable periods primarily reflects lower storage levels and increased NYMEX benchmark pricing.
- Market egress improved in 2021 as Enbridge's Line 3 pipeline replacement began operations on October 1, 2021, increasing incremental transportation by approximately 370,000 bbl/d.
- Increased market egress from western Canada has resulted in a more balanced market for heavy crude oil leading to less pricing volatility and stronger WCS pricing.
  - The WCS heavy oil differential as a percentage of WTI was 19% in 2021 and as of March 2, 2022 is approximately 13% for 2022, both of which are stronger than the historical range reflecting the positive impact of improved western Canadian egress on heavy oil pricing.
- Strong performance at the North West Redwater ("NWR") Refinery continues to increase local demand for heavy crude oil.
- As per the public update provided by Trans Mountain on February 18, 2022, construction of the 590,000 bbl/d Trans Mountain Expansion, on which Canadian Natural has committed 94,000 bbl/d, now targets mechanical completion in Q3/23. The total cost of the Trans Mountain Expansion is now estimated at approximately $21.4 billion.

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, resulted in average annual production of 1,234,906 BOE/d in 2021, with approximately 99% of total production located in G7 countries.
- In 2021, reflecting the strength of our effective and efficient operations and our high quality, long life low decline asset base, Canadian Natural generated robust annual free cash flow of approximately $8.0 billion, after dividend payments of approximately $2.2 billion and net capital expenditures of approximately $3.5 billion, excluding acquisitions.
- Direct returns to shareholders in 2021 were strong, totaling approximately $3.8 billion, comprised of approximately $2.2 billion of dividends and approximately $1.6 billion of share repurchases.
  - Canadian Natural increased its sustainable and growing dividend twice in 2021 for a combined increase of 38% to $2.35 per share annually, marking 2021 as the 21st consecutive year of dividend increases.
  - Share repurchases for cancellation during 2021, per the free cash flow allocation policy, totaled 33,644,400 shares at a weighted average price of $46.98 per share.
  - Subsequent to quarter end, up to and including March 2, 2022, the Company repurchased 10.5 million shares for total consideration of $680 million at a weighted average price of $64.79 per share.
  - Subsequent to quarter end, the Board of Directors has approved a 28% increase to our quarterly dividend to $0.75 per share, up from $0.5875 per share, payable on April 5, 2022.
- Canadian Natural executed on its commitment to further strengthen its balance sheet with strong financial results in 2021, reducing net debt by approximately $7.3 billion from year end 2020 levels and resulting in 2021 year end net debt of approximately $14.0 billion. In 2021, Canadian Natural executed on a number of strategic initiatives targeted to further enhance the strength of the Company's financial flexibility. These initiatives included:
  - The extension of the $1,000 million non-revolving term credit facility, originally due February 2022, to February 2023. The facility was fully repaid in Q4/21 and amended to allow for a re-draw of the full $1,000 million until March 31, 2022.
  - The repayment of $500 million of a $2,650 million non-revolving term credit facility, reducing the outstanding balance to $2,150 million. The Company repaid an additional $1,000 million on the facility in Q4/21, reducing the outstanding balance to $1,150 million as at December 31, 2021.
  - The repayment of US$500 million of 3.45% debt securities early, originally due November 2021.
  - The extension of both of its $2,425 million revolving credit facilities originally maturing June 2022 and June 2023, to June 2024 and June 2025, respectively and increased each facility by $70 million. In accordance with the terms of the extension, and by mutual agreement, $70 million of the original revolving credit facilities were not extended and will mature upon the original maturity date of June 2022 and June 2023, respectively.
  - The filing of two base shelf prospectuses that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and up to US$3,000 million of debt securities in the United States, both of which expire in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- Effective July 1, 2021, Canadian Natural enhanced its free cash flow allocation policy that states when net debt levels are below $15 billion, the Company will target to allocate 50% of free cash flow to share repurchases and 50% of free cash flow to the balance sheet. To the extent net debt is below $15 billion, such amount will be made available for strategic growth / acquisition opportunities. As year end 2021 net debt levels were approximately $14.0 billion (inclusive of the recent opportunistic acquisition of Storm which closed in Q4/21), Canadian Natural is targeting in 2022 to allocate 50% of free cash flow to the balance sheet, less any strategic growth capital / acquisitions, and 50% of free cash flow to share repurchases.

- As at December 31, 2021, the Company had significant liquidity of approximately $7.2 billion comprised of cash and cash equivalents, short-term investments and undrawn bank credit facilities of approximately $6.1 billion available. At December 31, 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.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE HIGHLIGHTS

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

Sustainability Reporting

Canadian Natural has been producing its sustainability report, the Stewardship Report to Stakeholders, since 2004 to report on our ongoing commitment to environmental performance, social responsibility and continuous improvement. This report provides a performance overview across the full range of Canadian Natural’s operations in Western Canada, the UK portion of the North Sea and Offshore Africa.

The Company aligns its reporting with recommendations from the Task Force on Climate-related Financial Disclosures and the reporting framework from the Sustainability Accounting Standards Board. Canadian Natural targets to publish its 2021 Stewardship Report to Stakeholders in Q3/21. Canadian Natural’s 2021 report will include third-party independent “reasonable assurance” on its scope 1 and 2 emissions (including methane emissions) and “limited assurance” on its scope 3 emissions.

Additionally, Canadian Natural will continue to outline its pathway to lower carbon emissions and its journey to achieve its goal of net zero GHG emissions in the oil sands. The report will display how Canadian Natural leverages technology and innovation to reduce its environmental footprint while ensuring safe, reliable, effective and efficient operations.

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 ("Pathways"). Canadian Natural and these companies operate approximately 95% 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 Pathways 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.
- In 2018, Canadian Natural was the first global oil company to announce an aspirational goal of achieving net zero emissions in its oil sands operations.
- Through the Company’s participation in the Pathways initiative with our industry partners and collaboration with the federal and Alberta governments, Canadian Natural is further refining its goal by targeting to achieve net zero emissions in its oil sands operations by 2050.
- The Company is currently working through the details with members of the Pathways initiative advance key milestones over the next decade as we accelerate related projects through the Pathways initiative.

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.

2021 YEAR END RESERVES

Determination of Reserves

For the year ended December 31, 2021, the Company retained Independent Qualified Reserves Evaluators (IQREs), Sproule Associates Limited, Sproule International Limited and GLJ Ltd., to evaluate and review all of the Company's proved and proved plus probable reserves. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

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

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

Summary of Company Gross Reserves

As of December 31, 2021
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
Total Company								
Proved								
Developed Producing	135	83	215	587	6,960	4,494	130	8,859
Developed Non-Producing	50	11	—	32	—	262	5	142
Undeveloped	115	74	56	2,012	37	7,413	283	3,812
Total Proved	300	169	270	2,631	6,998	12,168	418	12,813
Probable	125	80	118	1,706	537	8,080	224	4,137
Total Proved plus Probable	424	249	388	4,337	7,535	20,249	643	16,950

Notes to Reserves:

1. Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
2. Information in the reserves data tables may not add due to rounding. BOE values and oil and gas metrics may not calculate exactly due to rounding.
3. Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserves estimates are the 3-consultant-average of price forecasts developed by Sproule Associates Limited, GLJ Ltd. and McDaniel & Associates Consultants Ltd., dated December 31, 2021:

		2022	2023	2024	2025	2026
Crude Oil and NGL						
WTI	US$/bbl	72.83	68.78	66.76	68.09	69.45
WCS	C$/bbl	74.42	69.17	66.54	67.87	69.23
Canadian Light Sweet	C$/bbl	86.82	80.73	78.01	79.57	81.16
Cromer LSB	C$/bbl	87.30	82.30	79.69	81.29	82.92
Edmonton C5+	C$/bbl	91.85	85.53	82.98	84.63	86.33
Brent	US$/bbl	75.33	71.46	69.62	71.01	72.44
Natural gas						
AECO	C$/MMBtu	3.56	3.21	3.05	3.11	3.17
BC Westcoast Station 2	C$/MMBtu	3.48	3.14	2.98	3.03	3.10
Henry Hub	US$/MMBtu	3.85	3.44	3.17	3.24	3.30

   All prices increase at a rate of 2%/year after 2026.

   A foreign exchange rate of 0.7967 US$/C$ for 2022 and 0.7967 US$/C$ after 2022 was used in the year end 2021 evaluation.

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

5. Oil and gas metrics included herein are commonly used in the crude oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural’s performance over time. However, such measures are not reliable indicators of Canadian Natural’s future performance and future performance may vary.
6. Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.
7. Reserves replacement or Production replacement ratio is the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.
8. Reserves Life Index ("RLI") is based on the amount for the relevant reserves category divided by the 2022 proved developed producing production forecast prepared by the Independent Qualified Reserves Evaluators.
9. Finding, Development and Acquisition ("FD&A") costs excluding changes in Future Development Costs ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2021 by the sum of total additions and revisions for the relevant reserves category.
10. FD&A costs including changes in FDC are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2021 and net changes in FDC from December 31, 2020 to December 31, 2021 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment, decommissioning and reclamation costs.
11. Abandonment, decommissioning and reclamation ("ADR") costs included in the calculation of the Future Net Revenue (FNR) consist of both the Company's total Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as at December 31, 2021 and forecast estimates of ADR costs attributable to future development activity.

ADVISORY

Special Note Regarding non-GAPP and Other Financial Measures

This interim report includes references to non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure. These financial measures are used by the Company to evaluate its financial performance, financial position or cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than the most directly comparable financial measure presented in the Company's financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this interim report, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below as well as in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2021, dated March 2, 2022.

Free Cash Flow

Free cash flow is a non-GAAP financial measure that represents cash flows from 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 from operating activities, abandonment, certain movements in other long-term assets, less net capital expenditures before net property acquisitions and dividend 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.

	Year Ended	
($ millions)	**Dec 31, 2021**	Dec 31, 2020
Adjusted funds flow [1]	**$ 13,733**	$ 5,200
Less: Net Capital Expenditures [1]	**4,908**	3,206
Net Property Acquisitions [2]	**(1,425)**	(505)
Dividends on Common Shares	**2,170**	1,950
Free Cash Flow	**$ 8,080**	$ 549

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, as applicable, are provided in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2021, dated March 2, 2022.

(2) Amount includes net exploration and evaluation asset dispositions and net property acquisitions and the acquisition of a 5% net carried interest on an existing oil sands lease in the second quarter of 2021 per the Company's MD&A for the year ended December 31, 2021, dated March 2, 2022.

Capital Budget

Capital budget is a forward looking non-GAAP financial measure. The capital budget is based on net capital expenditures (Non-GAAP Financial Measure) and excludes net property acquisition costs. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for more details on Net Capital Expenditures.

Long term debt, net

Long term debt, net (also referred to as net debt) is a financial measure that is calculated as net current and long-term debt less cash and cash equivalents. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for more details.

Capital Efficiency

Capital efficiency is a supplementary financial measure that represents the capital investment required to add new or incremental production divided by the 12 month average rate of the new or incremental production. It is expressed as a dollar amount per flowing volume of a product ($/bbl/d, $/Mcf/d or $/BOE/d). The Company considers capital efficiency a key measure in evaluating its performance, as it demonstrates the efficiency of the Company's capital investments.

Break-even WTI Price

The break-even WTI price is a supplementary financial measure that represents the equivalent US dollar WTI price per barrel where the Company's adjusted funds flow is equal to the sum of maintenance capital and dividends. The Company considers the break-even WTI price a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. The break-even WTI price incorporates the non-GAAP financial measure adjusted funds flow as reconciled in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A. Maintenance capital is a supplementary financial measure that represents the capital required to maintain annual production at prior period levels.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

ADVISORY

Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to 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 and the North West Redwater bitumen upgrader and refinery; construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs") or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market; the development and deployment of technology and technological innovations; 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 any production curtailments mandated by the Government of Alberta); government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short, medium, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

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

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

Special Note Regarding Non-GAAP and Other Financial Measures

This MD&A includes references to non-GAAP measures, which include non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure ("NI 52-112"). Non-GAAP measures are used by the Company to evaluate its financial performance, financial position or cash flow. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided in the "Non-GAAP and Other Financial Measures" section of this MD&A.

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the Company's unaudited interim consolidated financial statements (the "financial statements") for the three months and year ended December 31, 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 financial statements for the three months and year ended December 31, 2021 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

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

The following discussion and analysis refers primarily to the Company's financial results for the three months and year ended December 31, 2021 in relation to the comparable periods in 2020 and the third 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 March 2, 2022.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Dec 31 2021	Sep 30 2021	Dec 31 2020	Year Ended Dec 31 2021	Dec 31 2020
Product sales [1]	**$ 10,190**	$ 8,521	$ 5,219	**$ 32,854**	$ 17,491
Crude oil and NGLs	**$ 8,979**	$ 7,607	$ 4,592	**$ 29,256**	$ 15,579
Natural gas	**$ 958**	$ 694	$ 496	**$ 2,716**	$ 1,478
Net earnings (loss)	**$ 2,534**	$ 2,202	$ 749	**$ 7,664**	$ (435)
Per common share – basic	**$ 2.16**	$ 1.87	$ 0.63	**$ 6.49**	$ (0.37)
– diluted	**$ 2.14**	$ 1.86	$ 0.63	**$ 6.46**	$ (0.37)
Adjusted net earnings (loss) from operations [2]	**$ 2,626**	$ 2,095	$ 176	**$ 7,420**	$ (756)
Per common share – basic [3]	**$ 2.24**	$ 1.78	$ 0.15	**$ 6.28**	$ (0.64)
– diluted [3]	**$ 2.21**	$ 1.77	$ 0.15	**$ 6.25**	$ (0.64)
Cash flows from operating activities	**$ 4,712**	$ 4,290	$ 1,270	**$ 14,478**	$ 4,714
Adjusted funds flow [2]	**$ 4,338**	$ 3,634	$ 1,708	**$ 13,733**	$ 5,200
Per common share – basic [3]	**$ 3.69**	$ 3.08	$ 1.45	**$ 11.63**	$ 4.40
– diluted [3]	**$ 3.66**	$ 3.07	$ 1.44	**$ 11.57**	$ 4.40
Cash flows used in investing activities	**$ 1,615**	$ 721	$ 624	**$ 3,703**	$ 2,819
Net capital expenditures [2]	**$ 1,804**	$ 1,011	$ 1,176	**$ 4,908**	$ 3,206

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

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

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

SUMMARY OF FINANCIAL HIGHLIGHTS

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

Net earnings for the year ended December 31, 2021 were $7,664 million compared with a net loss of $435 million for the year ended December 31, 2020. Net earnings for the year ended December 31, 2021 included non-operating items (after-tax) of $244 million compared with $321 million for the year ended December 31, 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 realized foreign exchange gain on the settlement of the cross currency swaps, the gain on acquisitions, the (gain) loss from investments, government grant income under the provincial well-site rehabilitation programs, and a provision relating to the Keystone XL pipeline project. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2021 were $7,420 million compared with an adjusted net loss from operations of $756 million for the year ended December 31, 2020.

Net earnings for the fourth quarter of 2021 were $2,534 million compared with $749 million for the fourth quarter of 2020 and $2,202 million for the third quarter of 2021. Net earnings for the fourth quarter of 2021 included non-operating items (after-tax) of $92 million compared with $573 million for the fourth quarter of 2020 and $107 million for the third 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 (gain) loss from investments, government grant income under the provincial well-site rehabilitation programs, and a provision relating to the Keystone XL pipeline project. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2021 were $2,626 million compared with $176 million for the fourth quarter of 2020 and $2,095 million for the third quarter of 2021.

Net earnings and adjusted net earnings from operations for the year ended December 31, 2021 compared with a net loss and an adjusted net loss from operations for the year ended December 31, 2020 primarily reflected:

- higher realized SCO sales price (1) in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGLs netbacks (1) and natural gas netbacks (1) in the Exploration and Production segments;
- higher natural gas sales volumes in the North America segment;
- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment; and
- lower depletion, depreciation and amortization expense.

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

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

The impacts of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the gain on acquisitions, income from North West Redwater Partnership ("NWRP"), and the (gain) loss 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 year ended December 31, 2021 were $14,478 million compared with $4,714 million for the year ended December 31, 2020. Cash flows from operating activities for the fourth quarter of 2021 were $4,712 million compared with $1,270 million for the fourth quarter of 2020 and $4,290 million for the third 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, and excluding the impact of depletion, depreciation and amortization expense.

Adjusted funds flow for the year ended December 31, 2021 was $13,733 million compared with $5,200 million for the year ended December 31, 2020. Adjusted funds flow for the fourth quarter of 2021 was $4,338 million compared with $1,708 million for the fourth quarter of 2020 and $3,634 million for the third 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 fourth quarter of 2021 increased 8% to 1,004,425 bbl/d, from 927,190 bbl/d for the fourth quarter of 2020 and increased 5% from 952,839 bbl/d for the third quarter of 2021. Natural gas production before royalties for the fourth quarter of 2021 increased 13% to 1,857 MMcf/d from 1,644 MMcf/d for the fourth quarter of 2020 and increased 9% from 1,708 MMcf/d for the third quarter of 2021. Total production before royalties for the fourth quarter of 2021 of 1,313,900 BOE/d increased 9% from 1,201,198 BOE/d for the fourth quarter of 2020 and increased 6% from 1,237,503 BOE/d for the third quarter of 2021. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production, before royalties" section of this MD&A.

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

Product Prices

In the Company's Exploration and Production segments, realized crude oil and NGLs prices [1] averaged $72.81 per bbl for the fourth quarter of 2021, an increase of 80% compared with $40.56 per bbl for the fourth quarter of 2020, and an increase of 7% from $68.06 per bbl for the third quarter of 2021. The realized natural gas price [1] increased 82% to average $5.35 per Mcf for the fourth quarter of 2021 from $2.94 per Mcf for the fourth quarter of 2020, and increased 30% from $4.13 per Mcf for the third quarter of 2021. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price increased 82% to average $88.48 per bbl for the fourth quarter of 2021 from $48.56 per bbl for the fourth quarter of 2020, and increased 9% from $81.54 per bbl for the third 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", "Realized Product Prices – Exploration and Production", and the "Oil Sands Mining and Upgrading" sections of this MD&A.

Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense [2] averaged $15.70 per bbl for the fourth quarter of 2021, an increase of 26% from $12.47 per bbl for the fourth quarter of 2020, and an increase of 6% from $14.78 per bbl for the third quarter of 2021. Natural gas production expense [2] averaged $1.12 per Mcf for the fourth quarter of 2021, comparable with $1.10 per Mcf for the fourth quarter of 2020 and a decrease of 4% from $1.17 per Mcf for the third quarter of 2021. In the Oil Sands Mining and Upgrading segment, production costs [2] averaged $19.55 per bbl for the fourth quarter of 2021, a decrease of 3% from $20.20 per bbl for the fourth quarter of 2020, and comparable with $19.86 per bbl for the third 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)	**Dec 31 2021**	Sep 30 2021	Jun 30 2021	Mar 31 2021
Product sales [1]	**$ 10,190**	$ 8,521	$ 7,124	$ 7,019
Crude oil and NGLs	**$ 8,979**	$ 7,607	$ 6,382	$ 6,288
Natural gas	**$ 958**	$ 694	$ 509	$ 555
Net earnings (loss)	**$ 2,534**	$ 2,202	$ 1,551	$ 1,377
Net earnings (loss) per common share				
– basic	**$ 2.16**	$ 1.87	$ 1.31	$ 1.16
– diluted	**$ 2.14**	$ 1.86	$ 1.30	$ 1.16

($ millions, except per common share amounts)	Dec 31 2020	Sep 30 2020	Jun 30 2020	Mar 31 2020
Product sales [1]	$ 5,219	$ 4,676	$ 2,944	$ 4,652
Crude oil and NGLs	$ 4,592	$ 4,202	$ 2,462	$ 4,323
Natural gas	$ 496	$ 338	$ 307	$ 337
Net earnings (loss)	$ 749	$ 408	$ (310)	$ (1,282)
Net earnings (loss) per common share				
– basic	$ 0.63	$ 0.35	$ (0.26)	$ (1.08)
– diluted	$ 0.63	$ 0.35	$ (0.26)	$ (1.08)

(1) Further details related to product sales for the three months ended December 31, 2021 and 2020 are disclosed in note 17 to the financial statements.

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

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

Volatility in the quarterly net earnings (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 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, (gain) loss from investments and income from NWRP** – Fluctuations due to the recognition of gains on acquisitions, (gain) loss from the investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("IPL") shares, 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 throughout 2021, partially in response to the OPEC+ decision to adhere to previously agreed upon production cut agreements. 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 fourth 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 December 31, 2021, the Company had undrawn bank credit facilities of $6,098 million. Including cash and cash equivalents and short-term investments, the Company had approximately $7,151 million in liquidity (1). The Company also has certain other dedicated credit facilities supporting letters of credit.

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

Capital Spending

Safe, reliable, effective and efficient operations continue to be a focus for the Company. On January 11, 2022, the Company announced its 2022 base capital budget (2) targeted at approximately $3,645 million. The budget also includes incremental strategic growth capital of approximately $700 million that targets to add future production and capacity in the Company's long life low decline thermal in situ and Oil Sands Mining and Upgrading assets. Production for 2022 is targeted between 1,270,000 BOE/d and 1,320,000 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 2022 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.

On December 9, 2020, the Company announced its 2021 capital budget targeted at approximately $3,205 million, and on August 5, 2021, the 2021 capital budget was increased to approximately $3,480 million, excluding acquisitions. Net capital expenditures for the year ended December 31, 2021 were $4,908 million, including the impact of acquisitions. Refer to the “Net Capital Expenditures” section of this MD&A for further details on the 2021 net capital expenditures.

On December 17, 2021, the Company completed the acquisition of all the issued and outstanding common shares of Storm Resources Limited ("Storm") for total cash consideration of approximately $771 million. At closing, the acquisition also included the assumption of long-term debt of approximately $183 million. Storm is involved in the exploration for and development of natural gas and natural gas liquids in the Montney region of British Columbia.

During the year ended December 31, 2021, the Company also completed a number of other opportunistic acquisitions. Two acquisitions consisted of natural gas assets located in the Montney region of British Columbia, with aggregate production of approximately 11,100 BOE/d. A third acquisition consisted of a net carried interest on an existing oil sands lease held by the Company, from which all Horizon production 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.

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

(2) Forward looking non-GAAP Financial Measure. The capital budget is based on net capital expenditures (Non-GAAP Financial Measure) and excludes net acquisition costs. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A for more details on Net Capital Expenditures.

Benchmark Commodity Prices

(Average for the period)	Three Months Ended **Dec 31 2021**	 Sep 30 2021	 Dec 31 2020	Year Ended **Dec 31 2021**	 Dec 31 2020
WTI benchmark price (US$/bbl)	**$ 77.17**	$ 70.55	$ 42.67	**$ 67.96**	$ 39.40
Dated Brent benchmark price (US$/bbl)	**$ 79.55**	$ 72.98	$ 44.52	**$ 70.49**	$ 42.27
WCS Heavy Differential from WTI (US$/bbl)	**$ 14.65**	$ 13.58	$ 9.30	**$ 13.04**	$ 12.57
SCO price (US$/bbl)	**$ 75.39**	$ 68.98	$ 39.69	**$ 66.36**	$ 36.26
Condensate benchmark price (US$/bbl)	**$ 79.10**	$ 69.22	$ 42.54	**$ 68.24**	$ 36.97
Condensate Differential from WTI (US$/bbl)	**$ (1.93)**	$ 1.33	$ 0.13	**$ (0.28)**	$ 2.43
NYMEX benchmark price (US$/MMBtu)	**$ 5.83**	$ 4.01	$ 2.66	**$ 3.85**	$ 2.08
AECO benchmark price (C$/GJ)	**$ 4.67**	$ 3.36	$ 2.62	**$ 3.38**	$ 2.12
US/Canadian dollar average exchange rate (US$)	**$ 0.7937**	$ 0.7936	$ 0.7674	**$ 0.7979**	$ 0.7454

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are directly impacted by fluctuations in foreign exchange rates. Product revenue continued to be impacted by the volatility of the Canadian dollar as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$67.96 per bbl for the year ended December 31, 2021, an increase of 72% from US$39.40 per bbl for the year ended December 31, 2020. WTI averaged US$77.17 per bbl for the fourth quarter of 2021, an increase of 81% from US$42.67 per bbl for the fourth quarter of 2020, and an increase of 9% from US$70.55 per bbl for the third 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$70.49 per bbl for the year ended December 31, 2021, an increase of 67% from US$42.27 per bbl for the year ended December 31, 2020. Brent averaged US$79.55 per bbl for the fourth quarter of 2021, an increase of 79% from US$44.52 per bbl for the fourth quarter of 2020, and an increase of 9% from US$72.98 per bbl for the third quarter of 2021.

The increase in WTI and Brent pricing for the three months and year ended December 31, 2021 from the comparable periods in 2020 primarily reflected the OPEC+ decision to adhere to the previously agreed upon production cut agreements. Additionally, global demand for crude oil increased due to improved economic conditions as a result of the lessening of earlier COVID-19 restrictions. The increase in WTI and Brent pricing for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected the continued recovery of global demand.

The WCS Heavy Differential averaged US$13.04 per bbl for the year ended December 31, 2021, a slight widening of 4% from US$12.57 per bbl for the year ended December 31, 2020. The WCS Heavy Differential averaged US$14.65 per bbl for the fourth quarter of 2021, a widening of 58% from US$9.30 per bbl for the fourth quarter of 2020, and a widening of 8% from US$13.58 per bbl for the third quarter of 2021. The widening of the WCS Heavy Differential for the fourth quarter of 2021 from the comparable periods primarily reflected the increase in WTI benchmark pricing and the widening of the US Gulf Coast heavy oil pricing.

The SCO price averaged US$66.36 per bbl for the year ended December 31, 2021, an increase of 83% from US$36.26 per bbl for the year ended December 31, 2020. The SCO price averaged US$75.39 per bbl for the fourth quarter of 2021, an increase of 90% from US$39.69 per bbl for the fourth quarter of 2020, and an increase of 9% from US$68.98 per bbl for the third quarter of 2021. The increase in SCO pricing for the three months and year ended December 31, 2021 from the comparable periods primarily reflected the increase in WTI benchmark pricing.

NYMEX natural gas prices averaged US$3.85 per MMBtu for the year ended December 31, 2021, an increase of 85% from US$2.08 per MMBtu for the year ended December 31, 2020. NYMEX natural gas prices averaged US$5.83 per MMBtu for the fourth quarter of 2021, an increase of $3.17 per MMBtu from US$2.66 per MMBtu for the fourth quarter of 2020, and an increase of 45% from US$4.01 per MMBtu for the third quarter of 2021. The increase in NYMEX natural gas prices for the three months and year ended December 31, 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 fourth quarter of 2021 from the third quarter of 2021 primarily reflected increased US Liquefied Natural Gas ("LNG") exports resulting from higher global LNG prices, together with low storage levels.

AECO natural gas prices averaged $3.38 per GJ for the year ended December 31, 2021, an increase of 59% from $2.12 per GJ for the year ended December 31, 2020. AECO natural gas prices averaged $4.67 per GJ for the fourth quarter of 2021, an increase of 78% from $2.62 per GJ for the fourth quarter of 2020, and an increase of 39% from $3.36 per GJ for the third quarter of 2021. The increase in AECO natural gas prices for the three months and year ended December 31, 2021 from the comparable periods primarily reflected lower storage levels and increased NYMEX benchmark pricing.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**478,738**	454,888	475,889	**472,621**	460,443
North America – Oil Sands Mining and Upgrading (1)	**493,406**	468,126	417,089	**448,133**	417,351
North Sea	**17,860**	16,294	17,057	**17,633**	23,142
Offshore Africa	**14,421**	13,531	17,155	**14,017**	17,022
	1,004,425	952,839	927,190	**952,404**	917,958
Natural gas (MMcf/d) (2)					
North America	**1,841**	1,698	1,623	**1,680**	1,450
North Sea	**3**	2	4	**3**	12
Offshore Africa	**13**	8	17	**12**	15
	1,857	1,708	1,644	**1,695**	1,477
Total barrels of oil equivalent (BOE/d)	**1,313,900**	1,237,503	1,201,198	**1,234,906**	1,164,136
Product mix					
Light and medium crude oil and NGLs	**10%**	10%	10%	**10%**	11%
Pelican Lake heavy crude oil	**4%**	4%	5%	**5%**	5%
Primary heavy crude oil	**5%**	5%	5%	**5%**	6%
Bitumen (thermal oil)	**20%**	20%	22%	**21%**	21%
Synthetic crude oil (1)	**38%**	38%	35%	**36%**	36%
Natural gas	**23%**	23%	23%	**23%**	21%
Percentage of gross revenue (1) (3) (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**90%**	91%	90%	**91%**	91%
Natural gas	**10%**	9%	10%	**9%**	9%

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

(2) Natural gas production volumes approximate sales volumes.

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**403,305**	386,416	433,697	**404,637**	420,906
North America – Oil Sands Mining and Upgrading	**440,492**	421,483	411,640	**410,385**	413,363
North Sea	**17,825**	16,256	17,023	**17,588**	23,086
Offshore Africa	**13,638**	12,901	16,416	**13,354**	16,306
	875,260	837,056	878,776	**845,964**	873,661
Natural gas (MMcf/d)					
North America	**1,721**	1,609	1,553	**1,593**	1,406
North Sea	**3**	2	4	**3**	12
Offshore Africa	**12**	7	16	**11**	14
	1,736	1,618	1,573	**1,607**	1,432
Total barrels of oil equivalent (BOE/d)	**1,164,613**	1,106,743	1,141,022	**1,113,878**	1,112,364

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

Record crude oil and NGLs production before royalties for the year ended December 31, 2021 averaged 952,404 bbl/d, an increase of 4% from 917,958 bbl/d for the year ended December 31, 2020. Crude oil and NGLs production for the fourth quarter of 2021 averaged 1,004,425 bbl/d, an increase of 8% from 927,190 bbl/d for the fourth quarter of 2020, and an increase of 5% from 952,839 bbl/d for the third quarter of 2021. The increase in crude oil and NGLs production for the year ended December 31, 2021 from 2020 and for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected strong operational performance in the Oil Sands Mining and Upgrading segment and increased thermal oil production. The increase in crude oil and NGLs production for the fourth quarter of 2021 from the fourth quarter of 2020 primarily reflected strong operational performance in the Oil Sands Mining and Upgrading segment, together with the timing of turnaround activities. Crude oil and NGLs production in North America Exploration and Production and Oil Sands Mining and Upgrading segments for 2021 as compared with 2020 reflected the impact of the Company's curtailment optimization strategy during mandatory Government of Alberta curtailment.

Annual crude oil and NGLs production for 2021 was within the Company's previously issued target of 940,000 bbl/d and 980,000 bbl/d. Annual crude oil and NGLs production for 2022 is targeted to average between 940,000 bbl/d and 982,000 bbl/d. Production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Natural gas production before royalties for the year ended December 31, 2021 of 1,695 MMcf/d increased 15% from 1,477 MMcf/d for the year ended December 31, 2020. Record natural gas production for the fourth quarter of 2021 of 1,857 MMcf/d increased 13% from 1,644 MMcf/d for the fourth quarter of 2020, and increased 9% from 1,708 MMcf/d for the third quarter of 2021. The increase in natural gas production for the three months and year ended December 31, 2021 from the comparable periods primarily reflected strong drilling results and production volumes from acquisitions, partially offset by natural field declines.

Annual natural gas production for 2021 was within the Company's previously issued target of 1,680 MMcf/d and 1,720 MMcf/d. Annual natural gas production for 2022 is targeted to average between 1,980 MMcf/d and 2,030 MMcf/d. Production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the year ended December 31, 2021 averaged 472,621 bbl/d, an increase of 3% from 460,443 bbl/d for the year ended December 31, 2020. North America crude oil and NGLs production for the fourth quarter of 2021 of 478,738 bbl/d was comparable with 475,889 bbl/d for the fourth quarter of 2020, and increased 5% from 454,888 bbl/d for the third quarter of 2021. The increase in crude oil and NGLs production for the year ended December 31, 2021 from 2020 and for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected increased thermal oil production and strong drilling results, partially offset by natural field declines.

Thermal oil production before royalties for the fourth quarter of 2021 averaged 263,110 bbl/d, comparable with 266,179 bbl/d for the fourth quarter of 2020, and an increase of 6% from 248,113 bbl/d for the third quarter of 2021. The increase in thermal oil production for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected the completion of planned turnaround activities at Jackfish.

Pelican Lake heavy crude oil production before royalties averaged 52,963 bbl/d for the fourth quarter of 2021, a decrease of 5% from 56,036 bbl/d for the fourth quarter of 2020, and was comparable with 53,923 bbl/d for the third quarter of 2021, demonstrating Pelican Lake's long life low decline production.

Natural gas production before royalties for the year ended December 31, 2021 averaged 1,680 MMcf/d, an increase of 16% from 1,450 MMcf/d for the year ended December 31, 2020. Natural gas production for the fourth quarter of 2021 averaged 1,841 MMcf/d, an increase of 13% from 1,623 MMcf/d for the fourth quarter of 2020, and an increase of 8% from 1,698 MMcf/d for the third quarter of 2021. The increase in natural gas production for the three months and year ended December 31, 2021 from the comparable periods primarily reflected strong drilling results and production volumes from acquisitions, partially offset by natural field declines.

North America – Oil Sands Mining and Upgrading

Record SCO production before royalties for the year ended December 31, 2021 of 448,133 bbl/d increased 7% from 417,351 bbl/d for the year ended December 31, 2020. Record SCO production for the fourth quarter of 2021 of 493,406 bbl/d increased 18% from 417,089 bbl/d for the fourth quarter of 2020 and increased 5% from 468,126 bbl/d for the third quarter of 2021. The increase in SCO production for the year ended December 31, 2021 from 2020 primarily reflected strong operational performance at AOSP following the completion of expansion activities at Scotford in the prior year. The increase in SCO production for the fourth quarter of 2021 from the comparable periods primarily reflected strong operational performance and the impact of the timing of turnaround activities in 2020 and 2021.

North Sea

North Sea crude oil production before royalties for the year ended December 31, 2021 of 17,633 bbl/d decreased 24% from 23,142 bbl/d for the year ended December 31, 2020. North Sea crude oil production for the fourth quarter of 2021 of 17,860 bbl/d increased 5% from 17,057 bbl/d for the fourth quarter of 2020 and increased 10% from 16,294 bbl/d for the third quarter of 2021. The decrease in production for the year ended December 31, 2021 from 2020 primarily reflected natural field declines and planned maintenance activities. The increase in production for the fourth quarter of 2021 from the comparable periods primarily reflected planned maintenance activities during the fourth quarter of 2020 and third quarter of 2021.

Offshore Africa

Offshore Africa crude oil production before royalties for the year ended December 31, 2021 decreased 18% to 14,017 bbl/d from 17,022 bbl/d for the year ended December 31, 2020. Offshore Africa crude oil production for the fourth quarter of 2021 of 14,421 bbl/d decreased 16% from 17,155 bbl/d for the fourth quarter of 2020 and increased 7% from 13,531 bbl/d for the third quarter of 2021. The decrease in production for the three months and year ended December 31, 2021 from the comparable periods in 2020 primarily reflected maintenance activities and natural field declines. The increase in production for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected the completion of planned maintenance activities at Espoir in the fourth quarter.

International Crude Oil Inventory Volumes

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

(bbl)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020
North Sea	**—**	295,014	450,889
Offshore Africa	**727,439**	—	521,244
	727,439	295,014	972,133

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Crude oil and NGLs ($/bbl) (1)					
Realized price (2)	**$ 72.81**	$ 68.06	$ 40.56	**$ 63.71**	$ 31.90
Transportation (2)	**3.93**	4.00	3.81	**3.86**	3.85
Realized price, net of transportation (2)	**68.88**	64.06	36.75	**59.85**	28.05
Royalties (3)	**10.67**	9.46	3.34	**8.59**	2.59
Production expense (4)	**15.70**	14.78	12.47	**14.71**	12.42
Netback (2)	**$ 42.51**	$ 39.82	$ 20.94	**$ 36.55**	$ 13.04
Natural gas ($/Mcf) (1)					
Realized price (5)	**$ 5.35**	$ 4.13	$ 2.94	**$ 4.07**	$ 2.40
Transportation (6)	**0.42**	0.44	0.42	**0.45**	0.43
Realized price, net of transportation	**4.93**	3.69	2.52	**3.62**	1.97
Royalties (3)	**0.35**	0.22	0.13	**0.22**	0.08
Production expense (4)	**1.12**	1.17	1.10	**1.18**	1.18
Netback (2)	**$ 3.46**	$ 2.30	$ 1.29	**$ 2.22**	$ 0.71
Barrels of oil equivalent ($/BOE) (1)					
Realized price (2)	**$ 57.72**	$ 52.09	$ 32.61	**$ 49.67**	$ 26.15
Transportation (2)	**3.40**	3.50	3.37	**3.44**	3.44
Realized price, net of transportation (2)	**54.32**	48.59	29.24	**46.23**	22.71
Royalties (3)	**7.48**	6.45	2.44	**5.98**	1.89
Production expense (4)	**12.33**	11.91	10.43	**11.98**	10.67
Netback (2)	**$ 34.51**	$ 30.23	$ 16.37	**$ 28.27**	$ 10.15

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

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

(3) Calculated as royalties divided by respective sales volumes.

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

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

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

REALIZED PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Crude oil and NGLs ($/bbl) (1)					
North America (2)	**$ 71.57**	$ 66.03	$ 39.54	**$ 62.10**	$ 30.31
North Sea (3)	**$ 100.45**	$ 96.11	$ 56.18	**$ 87.98**	$ 50.09
Offshore Africa (3)	**$ 75.42**	$ 91.73	$ 49.05	**$ 85.71**	$ 50.95
Average (2)	**$ 72.81**	$ 68.06	$ 40.56	**$ 63.71**	$ 31.90
Natural gas ($/Mcf) (1) (3)					
North America	**$ 5.33**	$ 4.12	$ 2.91	**$ 4.05**	$ 2.34
North Sea	**$ 3.20**	$ 3.75	$ 1.41	**$ 2.94**	$ 2.74
Offshore Africa	**$ 9.00**	$ 6.83	$ 6.64	**$ 7.17**	$ 7.77
Average	**$ 5.35**	$ 4.13	$ 2.94	**$ 4.07**	$ 2.40
Average ($/BOE) (1) (2)	**$ 57.72**	$ 52.09	$ 32.61	**$ 49.67**	$ 26.15

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

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

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

North America

North America realized crude oil and NGLs prices increased by $31.79 per bbl to average $62.10 per bbl for the year ended December 31, 2021 from $30.31 per bbl for the year ended December 31, 2020. North America realized crude oil and NGLs prices increased 81% to average $71.57 per bbl for the fourth quarter of 2021 from $39.54 per bbl for the fourth quarter of 2020, and increased 8% from $66.03 per bbl for the third quarter of 2021. The increase in realized crude oil and NGLs prices for the three months and year ended December 31, 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 fourth quarter of 2021 contributed approximately 173,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 73% to average $4.05 per Mcf for the year ended December 31, 2021 from $2.34 per Mcf for the year ended December 31, 2020. North America realized natural gas prices increased 83% to average $5.33 per Mcf for the fourth quarter of 2021 from $2.91 per Mcf for the fourth quarter of 2020, and increased 29% from $4.12 per Mcf for the third quarter of 2021. The increase in realized natural gas prices for the three months and year ended December 31, 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)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020
Wellhead Price (1)			
Light and medium crude oil and NGLs ($/bbl)	**$ 74.41**	$ 63.88	$ 38.03
Pelican Lake heavy crude oil ($/bbl)	**$ 77.40**	$ 71.92	$ 43.21
Primary heavy crude oil ($/bbl)	**$ 75.47**	$ 68.72	$ 42.01
Bitumen (thermal oil) ($/bbl)	**$ 68.45**	$ 64.81	$ 38.67
Natural gas ($/Mcf)	**$ 5.33**	$ 4.12	$ 2.91

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

North Sea

North Sea realized crude oil and NGLs prices increased 76% to average $87.98 per bbl for the year ended December 31, 2021 from $50.09 per bbl for the year ended December 31, 2020. North Sea realized crude oil and NGLs prices increased 79% to average $100.45 per bbl for the fourth quarter of 2021 from $56.18 per bbl for the fourth quarter of 2020 and increased 5% from $96.11 per bbl for the third 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 months and year ended December 31, 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 $85.71 per bbl for the year ended December 31, 2021 from $50.95 per bbl for the year ended December 31, 2020. Offshore Africa realized crude oil and NGLs prices increased 54% to average $75.42 per bbl for the fourth quarter of 2021 from $49.05 per bbl for the fourth quarter of 2020 and decreased 18% from $91.73 per bbl for the third 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 months and year ended December 31, 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			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 11.21**	$ 10.02	$ 3.52	**$ 9.06**	$ 2.72
North Sea	**$ 0.19**	$ 0.22	$ 0.11	**$ 0.19**	$ 0.12
Offshore Africa	**$ 4.10**	$ 4.27	$ 2.11	**$ 3.94**	$ 2.17
Average	**$ 10.67**	$ 9.46	$ 3.34	**$ 8.59**	$ 2.59
Natural gas ($/Mcf) (1)					
North America	**$ 0.35**	$ 0.22	$ 0.13	**$ 0.22**	$ 0.07
Offshore Africa	**$ 0.41**	$ 0.31	$ 0.30	**$ 0.33**	$ 0.37
Average	**$ 0.35**	$ 0.22	$ 0.13	**$ 0.22**	$ 0.08
Average ($/BOE) (1)	**$ 7.48**	$ 6.45	$ 2.44	**$ 5.98**	$ 1.89

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

North America

North America crude oil and NGLs and natural gas royalties for the three months and year ended December 31, 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 (1) averaged approximately 15% of product sales for the year ended December 31, 2021 compared with 9% of product sales for the year ended December 31, 2020. Crude oil and NGLs royalty rates averaged approximately 16% of product sales for the fourth quarter of 2021 compared with 9% for the fourth quarter of 2020 and 15% for the third quarter of 2021. The increase in royalty rates for the three months and year ended December 31, 2021 from the comparable periods in 2020 was primarily due to higher benchmark prices together with fluctuations in the WCS Heavy Differential.

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

Natural gas royalty rates averaged approximately 5% of product sales for the year ended December 31, 2021 compared with 3% of product sales for the year ended December 31, 2020. Natural gas royalty rates averaged approximately 7% of product sales for the fourth quarter of 2021 compared with 4% for the fourth quarter of 2020 and 5% for the third quarter of 2021. The increase in royalty rates for the three months and year ended December 31, 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 year ended December 31, 2021, compared with 4% of product sales for the year ended December 31, 2020. Royalty rates as a percentage of product sales averaged approximately 5% for the fourth quarter of 2021 compared with 4% of product sales for the fourth quarter of 2020 and 5% for the third 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			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 13.55**	$ 13.33	$ 10.81	**$ 13.12**	$ 11.21
North Sea	**$ 64.96**	$ 55.90	$ 52.42	**$ 54.13**	$ 36.51
Offshore Africa	**$ 16.75**	$ 14.53	$ 11.74	**$ 14.73**	$ 13.29
Average	**$ 15.70**	$ 14.78	$ 12.47	**$ 14.71**	$ 12.42
Natural gas ($/Mcf) (1)					
North America	**$ 1.08**	$ 1.14	$ 1.07	**$ 1.15**	$ 1.14
North Sea	**$ 9.19**	$ 8.86	$ 5.29	**$ 7.31**	$ 3.72
Offshore Africa	**$ 4.52**	$ 5.76	$ 3.07	**$ 4.41**	$ 3.58
Average	**$ 1.12**	$ 1.17	$ 1.10	**$ 1.18**	$ 1.18
Average ($/BOE) (1)	**$ 12.33**	$ 11.91	$ 10.43	**$ 11.98**	$ 10.67

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

North America

North America crude oil and NGLs production expense for the year ended December 31, 2021 averaged $13.12 per bbl, an increase of 17% from $11.21 per bbl for the year ended December 31, 2020. North America crude oil and NGLs production expense for the fourth quarter of 2021 of $13.55 per bbl increased 25% from $10.81 per bbl for the fourth quarter of 2020 and was comparable with $13.33 per bbl for the third quarter of 2021. The increase in crude oil and NGLs production expense per bbl for the three months and year ended December 31, 2021 from the comparable periods in 2020 primarily reflected increased energy costs.

North America natural gas production expense for the year ended December 31, 2021 averaged $1.15 per Mcf, comparable with $1.14 per Mcf for the year ended December 31, 2020. North America natural gas production expense for the fourth quarter of 2021 of $1.08 per Mcf was comparable with $1.07 per Mcf for the fourth quarter of 2020 and decreased 5% from $1.14 per Mcf for the third quarter of 2021. The decrease in natural gas production expense for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected higher production volumes and the Company's strong focus on cost control.

North Sea

North Sea crude oil production expense for the year ended December 31, 2021 averaged $54.13 per bbl, an increase of 48% from $36.51 per bbl for the year ended December 31, 2020. North Sea crude oil production expense for the fourth quarter of 2021 of $64.96 per bbl increased 24% from $52.42 per bbl for the fourth quarter of 2020 and increased 16% from $55.90 per bbl for the third quarter of 2021. The increase in crude oil production expense per bbl for the year ended December 31, 2021 from 2020 primarily reflected lower volumes, on a relatively fixed cost base, as well as higher natural gas and CO_2 costs. The increase in crude oil production expense per barrel for the fourth quarter of 2021 from the comparable periods primarily reflected higher natural gas and CO_2 costs. North Sea production expense also reflected fluctuations in the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the year ended December 31, 2021 averaged $14.73 per bbl, an increase of 11% from $13.29 per bbl for the year ended December 31, 2020. Offshore Africa crude oil production expense for the fourth quarter of 2021 of $16.75 per bbl increased 43% from $11.74 per bbl for the fourth quarter of 2020 and increased 15% from $14.53 per bbl for the third quarter of 2021. The increase in crude oil production expense per bbl for the three months and year ended December 31, 2021 from the comparable periods primarily reflected the timing of liftings from various fields that have different cost structures, together with lower volumes, on a relatively fixed cost base. Offshore Africa production expense also reflected fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
North America	**$ 939**	$ 881	$ 1,017	**$ 3,569**	$ 3,780
North Sea	**33**	40	61	**160**	277
Offshore Africa	**19**	48	54	**142**	190
Depletion, Depreciation and Amortization	**$ 991**	$ 969	$ 1,132	**$ 3,871**	$ 4,247
$/BOE (1)	**$ 13.03**	$ 13.70	$ 15.55	**$ 13.49**	$ 15.45

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

Depletion, depreciation and amortization expense for the year ended December 31, 2021 of $13.49 per BOE decreased 13% from $15.45 per BOE for the year ended December 31, 2020. Depletion, depreciation and amortization expense for the fourth quarter of 2021 of $13.03 per BOE decreased 16% from $15.55 per BOE for the fourth quarter of 2020 and decreased 5% from $13.70 per BOE for the third quarter of 2021. The decrease in depletion, depreciation and amortization expense per BOE for the three months and year ended December 31, 2021 from the comparable periods in 2020 primarily reflected lower depletion rates in the North America Exploration and Production segment and lower volumes in the North Sea, which has higher depletion rates. The decrease in depletion, depreciation and amortization expense per BOE for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected the product mix in the North America Exploration and Production segment.

Depletion, depreciation and amortization expense on an absolute and per BOE basis also reflects the impact of the timing of liftings from each field in the North Sea and Offshore Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
North America	**$ 25**	$ 26	$ 24	**$ 101**	$ 97
North Sea	**5**	6	8	**21**	30
Offshore Africa	**2**	1	1	**6**	6
Asset Retirement Obligation Accretion	**$ 32**	$ 33	$ 33	**$ 128**	$ 133
$/BOE (1)	**$ 0.42**	$ 0.45	$ 0.45	**$ 0.44**	$ 0.48

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2021 of $0.44 per BOE decreased 8% from $0.48 per BOE for the year ended December 31, 2020. Asset retirement obligation accretion expense for the fourth quarter of 2021 of $0.42 per BOE decreased 7% from $0.45 per BOE for the fourth quarter of 2020 and for the third 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. Record SCO production in the fourth quarter of 2021 of 493,406 bbl/d primarily reflected strong operational performance.

The Company incurred production costs, excluding natural gas costs, of $796 million and $17.86 per bbl for the fourth quarter of 2021, comparable with $802 million and a 4% decrease from $18.63 per bbl for the third quarter of 2021, reflecting record production volumes, together with the Company's strong focus on cost control.

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

	Three Months Ended			Year Ended	
($/bbl)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Realized SCO sales price (1)	**$ 88.48**	$ 81.54	$ 48.56	**$ 77.95**	$ 43.98
Bitumen value for royalty purposes (2)	**$ 65.80**	$ 62.28	$ 34.70	**$ 58.39**	$ 25.82
Bitumen royalties (3)	**$ 9.16**	$ 8.21	$ 0.59	**$ 6.62**	$ 0.51
Transportation (1)	**$ 1.33**	$ 1.14	$ 1.36	**$ 1.21**	$ 1.23

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

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

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

The realized SCO sales price averaged $77.95 per bbl for the year ended December 31, 2021, an increase of 77% from $43.98 per bbl for the year ended December 31, 2020. The realized SCO sales price averaged $88.48 per bbl for the fourth quarter of 2021, an increase of 82% from $48.56 per bbl for the fourth quarter of 2020 and an increase of 9% from $81.54 per bbl for the third quarter of 2021. The increase in the realized SCO sales price for the three months and year ended December 31, 2021 from the comparable periods primarily reflected the increase in WTI benchmark pricing.

The increase in bitumen royalties per bbl for the three months and year ended December 31, 2021 from the comparable periods primarily reflected the impact of higher prevailing bitumen pricing and AOSP reaching full payout.

Transportation expense averaged $1.21 per bbl for the year ended December 31, 2021, comparable with $1.23 per bbl for the year ended December 31, 2020. For the fourth quarter of 2021, transportation expense of $1.33 per bbl was comparable with $1.36 per bbl for the fourth quarter of 2020 and increased 17% from $1.14 per bbl for the third quarter of 2021. The increase in transportation expense per bbl for the fourth quarter of 2021 compared to the third quarter of 2021 reflected the impact of US Gulf Coast sales.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Production costs, excluding natural gas costs	**$ 796**	$ 802	$ 736	**$ 3,176**	$ 2,968
Natural gas costs	**75**	53	51	**238**	146
Production costs	**$ 871**	$ 855	$ 787	**$ 3,414**	$ 3,114

($/bbl)	Three Months Ended Dec 31 2021	Sep 30 2021	Dec 31 2020	Year Ended Dec 31 2021	Dec 31 2020
Production costs, excluding natural gas costs (1)	**$ 17.86**	$ 18.63	$ 18.89	**$ 19.45**	$ 19.50
Natural gas costs (2)	**1.69**	1.23	1.31	**1.46**	0.96
Production costs (3)	**$ 19.55**	$ 19.86	$ 20.20	**$ 20.91**	$ 20.46
Sales volumes (bbl/d)	**483,972**	467,772	423,438	**447,230**	415,741

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

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

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

Production costs for the year ended December 31, 2021 of $20.91 per bbl were comparable with $20.46 per bbl for the year ended December 31, 2020. Production costs for the fourth quarter of 2021 averaged $19.55 per bbl, a decrease of 3% from $20.20 per bbl for the fourth quarter of 2020 and was comparable with $19.86 per bbl for the third quarter of 2021. Production costs per bbl for the year ended December 31, 2021 as compared to 2020 primarily reflected the impact of higher energy costs, including natural gas and diesel, offset by the impact of record production volumes, together with the Company's strong focus on cost control. The decrease in production costs per bbl for the fourth quarter of 2021 from the comparable period in 2020 primarily reflected record production volumes, together with the Company's strong focus on cost control.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended Dec 31 2021	Sep 30 2021	Dec 31 2020	Year Ended Dec 31 2021	Dec 31 2020
Depletion, depreciation and amortization	**$ 478**	$ 469	$ 479	**$ 1,838**	$ 1,784
$/bbl (1)	**$ 10.73**	$ 10.90	$ 12.31	**$ 11.26**	$ 11.73

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

Depletion, depreciation and amortization expense for the year ended December 31, 2021 of $11.26 per bbl decreased 4% from $11.73 per bbl for the year ended December 31, 2020. Depletion, depreciation and amortization expense for the fourth quarter of 2021 of $10.73 per bbl decreased 13% from $12.31 per bbl for the fourth quarter of 2020, and was comparable with $10.90 per bbl for the third quarter of 2021. The decrease in depletion, depreciation and amortization on a per barrel basis for the three months and year ended December 31, 2021 from the comparable periods in 2020 primarily reflected the impact of fluctuating sales volumes from underlying operations.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended Dec 31 2021	Sep 30 2021	Dec 31 2020	Year Ended Dec 31 2021	Dec 31 2020
Asset retirement obligation accretion	**$ 14**	$ 14	$ 18	**$ 57**	$ 72
$/bbl (1)	**$ 0.32**	$ 0.33	$ 0.47	**$ 0.35**	$ 0.47

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2021 of $0.35 per bbl decreased 26% from $0.47 per bbl for the year ended December 31, 2020. Asset retirement obligation accretion expense of $0.32 per bbl for the fourth quarter of 2021 decreased 32% from $0.47 per bbl for the fourth quarter of 2020 and decreased 3% from $0.33 per bbl for the third 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 **Dec 31 2021**	 Sep 30 2021	 Dec 31 2020	Year Ended **Dec 31 2021**	 Dec 31 2020
Product sales					
Midstream activities	**$ 17**	$ 21	$ 21	**$ 78**	$ 83
NWRP, refined product sales and other	**200**	179	99	**681**	202
Segmented revenue	**217**	200	120	**759**	285
Less:					
NWRP, refining toll	**37**	46	72	**213**	166
Midstream activities	**5**	4	3	**21**	18
Production expense	**42**	50	75	**234**	184
NWRP, transportation and feedstock costs	**165**	146	83	**550**	181
Depreciation	**4**	4	4	**15**	15
Income from NWRP	**—**	—	—	**(400)**	—
Segmented earnings (loss)	**$ 6**	$ —	$ (42)	**$ 360**	$ (95)

The Company's Midstream and Refining assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose and the Company's 50% equity investment in NWRP.

NWRP operates a 50,000 bbl/d bitumen upgrader and refinery that processes approximately 12,500 bbl/d (25% toll payer) of bitumen feedstock for the Company and 37,500 bbl/d (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period. Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment. For the fourth quarter of 2021, production of ultra-low sulphur diesel and other refined products averaged 71,433 BOE/d (17,858 BOE/d to the Company), (three months ended December 31, 2020 – 65,670 BOE/d; 16,417 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 December 31, 2021, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $562 million (December 31, 2020 – $153 million). For the three months ended December 31, 2021, unrecognized share of the equity loss was $12 million (year ended December 31, 2021 – unrecognized equity loss of $9 million and partnership distributions of $400 million; three months ended December 31, 2020 – unrecognized equity income of $6 million; year ended December 31, 2020 – unrecognized equity loss of $94 million).

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Expense ($ millions)	**$ 97**	$ 87	$ 107	**$ 366**	$ 391
$/BOE (1)	**$ 0.81**	$ 0.77	$ 0.96	**$ 0.81**	$ 0.92
Sales volumes (BOE/d) (2)	**1,310,878**	1,236,813	1,213,746	**1,233,457**	1,166,862

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

(2) Total Company sales volumes.

Administration expense for the year ended December 31, 2021 of $0.81 per BOE decreased 12% from $0.92 per BOE for the year ended December 31, 2020. Administration expense for the fourth quarter of 2021 of $0.81 per BOE decreased 16% from $0.96 per BOE for the fourth quarter of 2020 and increased 5% from $0.77 per BOE for the third quarter of 2021. The decrease in administration expense per BOE for the three months and year ended December 31, 2021 from the comparable periods in 2020 was primarily due to higher sales volumes and higher overhead recoveries. The increase in administration expense per BOE for the fourth quarter of 2021 from the third quarter of 2021 was primarily due to higher personnel costs, partially offset by the impact of higher overhead recoveries.

SHARE-BASED COMPENSATION

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Expense (recovery)	**$ 191**	$ 57	$ 123	**$ 514**	$ (82)

The Company's Stock Option Plan provides employees with the right to receive common shares or a cash payment in exchange for stock options surrendered. The Performance Share Unit ("PSU") plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met.

The Company recognized a $514 million share-based compensation expense for the year ended December 31, 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. An expense of $79 million related to PSUs granted to certain executive employees was included in the share-based compensation expense for the year ended December 31, 2021 (December 31, 2020 – $21 million expense).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except effective interest rate)	Three Months Ended **Dec 31 2021**	Sep 30 2021	Dec 31 2020	Year Ended **Dec 31 2021**	Dec 31 2020
Interest and other financing expense	**$ 171**	$ 178	$ 177	**$ 711**	$ 756
Interest income and other (1)	**2**	3	19	**32**	72
Capitalized interest (1)	**—**	—	3	**—**	24
Interest on long-term debt and lease liabilities (1)	**$ 173**	$ 181	$ 199	**$ 743**	$ 852
Average current and long-term debt (2)	**$ 16,084**	$ 18,165	$ 22,439	**$ 18,935**	$ 22,446
Average lease liabilities (2)	**1,578**	1,599	1,698	**1,619**	1,708
Average long-term debt and lease liabilities (2)	**$ 17,662**	$ 19,764	$ 24,137	**$ 20,554**	$ 24,154
Average effective interest rate (3) (4)	**3.9%**	3.6%	3.3%	**3.5%**	3.5%
Interest and other financing expense per $/BOE (5)	**$ 1.42**	$ 1.56	$ 1.59	**$ 1.58**	$ 1.77
Sales volumes (BOE/d) (6)	**1,310,878**	1,236,813	1,213,746	**1,233,457**	1,166,862

(1) Item is a component of interest and other financing expense.

(2) The average of current and long-term debt and lease liabilities outstanding during the respective period.

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

(4) Calculated as the total of interest on long-term debt and lease liabilities divided by the average long-term debt and lease liabilities balance for the respective period. The Company presents its average effective interest rate for financial statement users to evaluate the Company's average cost of debt borrowings.

(5) Calculated as interest and other financing expense divided by sales volumes.

(6) Total Company sales volumes.

Interest and other financing expense per BOE for the year ended December 31, 2021 decreased 11% to $1.58 per BOE from $1.77 per BOE for the year ended December 31, 2020. Interest and other financing expense per BOE for the fourth quarter of 2021 decreased 11% to $1.42 per BOE from $1.59 per BOE for the fourth quarter of 2020 and decreased 9% from $1.56 per BOE for the third quarter of 2021. The decrease in interest expense and other financing expense per BOE for the three months and year ended December 31, 2021 from the comparable periods was primarily due to higher sales volumes and lower average debt levels in 2021, partially offset by lower interest income.

The Company's average effective interest rate for the fourth quarter of 2021 increased from the third quarter of 2021 primarily due to the repayment of outstanding bank credit facilities and less US commercial paper outstanding.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Natural gas financial instruments	**$ 6**	$ 14	$ (2)	**$ 17**	$ 16
Crude oil and NGLs financial instruments	**(1)**	—	—	**(1)**	—
Foreign currency contracts	**(11)**	(18)	25	**1**	16
Net realized (gain) loss	**(6)**	(4)	23	**17**	32
Natural gas financial instruments	**(10)**	(18)	(27)	**11**	(36)
Crude oil and NGLs financial instruments	**2**	—	—	**2**	—
Foreign currency contracts	**16**	(1)	6	**6**	(3)
Net unrealized loss (gain)	**8**	(19)	(21)	**19**	(39)
Net loss (gain)	**$ 2**	$ (23)	$ 2	**$ 36**	$ (7)

During the year ended December 31, 2021, net realized risk management losses were related to the settlement of natural gas financial instruments, crude oil and NGLs financial instruments and foreign currency contracts. The Company recorded a net unrealized loss of $19 million ($16 million after-tax of $3 million) on its risk management activities for the year ended December 31, 2021, including an unrealized loss of $8 million ($10 million after-tax of $2 million) for the fourth quarter of 2021 (September 30, 2021 – unrealized gain of $19 million, $15 million after-tax of $4 million; December 31, 2020 – unrealized gain of $21 million, $16 million after-tax of $5 million).

Further details related to outstanding derivative financial instruments at December 31, 2021 are disclosed in note 15 to the financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Net realized (gain) loss	**$ (27)**	$ 84	$ 21	**$ 78**	$ (159)
Net unrealized (gain) loss	**(79)**	197	(534)	**(205)**	(116)
Net (gain) loss (1)	**$ (106)**	$ 281	$ (513)	**$ (127)**	$ (275)

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

The net realized foreign exchange loss for the year ended December 31, 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 year ended December 31, 2021 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt and 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 December 31, 2021 was US$0.7901 (September 30, 2021 – US$0.7843, December 31, 2020 – US$0.7840).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended Dec 31 2021	Sep 30 2021	Dec 31 2020	Year Ended Dec 31 2021	Dec 31 2020
North America [(1)]	**$ 691**	$ 541	$ 42	**$ 1,841**	$ (245)
North Sea	**(3)**	4	—	**7**	(4)
Offshore Africa	**3**	7	5	**21**	17
PRT [(2)] – North Sea	**(12)**	(5)	(14)	**(34)**	(31)
Other taxes	**4**	4	2	**13**	6
Current income tax	**683**	551	35	**1,848**	(257)
Deferred income tax	**193**	56	(25)	**399**	(181)
Income tax	**$ 876**	$ 607	$ 10	**$ 2,247**	$ (438)
Earnings (loss) before taxes	**$ 3,410**	$ 2,809	$ 759	**$ 9,911**	$ (873)
Effective tax rate on net earnings (loss) [(3)]	**26%**	22%	1%	**23%**	50%
Income tax	**$ 876**	$ 607	$ 10	**$ 2,247**	$ (438)
Tax effect on non-operating items [(4)]	**—**	(6)	34	**5**	29
Current PRT - North Sea	**12**	5	14	**34**	31
Other taxes	**(4)**	(4)	(2)	**(13)**	(6)
Effective tax on adjusted net earnings (loss)	**$ 884**	$ 602	$ 56	**$ 2,273**	$ (384)
Adjusted net earnings (loss) from operations [(5)]	**$ 2,626**	$ 2,095	$ 176	**$ 7,420**	$ (756)
Effective tax on adjusted net earnings (loss)	**884**	602	56	**2,273**	(384)
Adjusted net earnings (loss) from operations, before taxes	**$ 3,510**	$ 2,697	$ 232	**$ 9,693**	$ (1,140)
Effective tax rate on adjusted net earnings (loss) from operations [(6) (7)]	**25%**	22%	24%	**23%**	34%

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

(2) Petroleum Revenue Tax.

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

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

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

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

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

The effective tax rate on net earnings (loss) and adjusted net earnings (loss) from operations for the three months and year ended December 31, 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 months and year ended December 31, 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] [2]

($ millions)	Three Months Ended Dec 31 2021	Sep 30 2021	Dec 31 2020	Year Ended Dec 31 2021	Dec 31 2020
Exploration and Evaluation					
Net property dispositions	**$ (6)**	$ (1)	$ (1)	**$ (11)**	$ (31)
Net expenditures	**2**	5	9	**12**	36
Total Exploration and Evaluation	**(4)**	4	8	**1**	5
Property, Plant and Equipment					
Net property acquisitions [3] [4]	**973**	131	522	**1,112**	536
Well drilling, completion and equipping	**196**	232	115	**918**	429
Production and related facilities	**180**	244	131	**802**	580
Other	**23**	12	20	**64**	60
Total Property, Plant and Equipment	**1,372**	619	788	**2,896**	1,605
Total Exploration and Production	**1,368**	623	796	**2,897**	1,610
Oil Sands Mining and Upgrading					
Project costs	**65**	69	86	**236**	258
Sustaining capital	**270**	233	212	**1,035**	839
Turnaround costs	**23**	19	22	**145**	196
Other [5]	**1**	3	4	**331**	30
Total Oil Sands Mining and Upgrading	**359**	324	324	**1,747**	1,323
Midstream and Refining	**3**	3	1	**9**	5
Head office	**7**	7	3	**23**	19
Abandonments expenditures, net [2]	**67**	54	52	**232**	249
Net capital expenditures	**$ 1,804**	$ 1,011	$ 1,176	**$ 4,908**	$ 3,206
By segment					
North America	**$ 1,301**	$ 564	$ 729	**$ 2,662**	$ 1,389
North Sea	**48**	49	34	**173**	122
Offshore Africa	**19**	10	33	**62**	99
Oil Sands Mining and Upgrading	**359**	324	324	**1,747**	1,323
Midstream and Refining	**3**	3	1	**9**	5
Head office	**7**	7	3	**23**	19
Abandonments expenditures, net [2]	**67**	54	52	**232**	249
Net capital expenditures	**$ 1,804**	$ 1,011	$ 1,176	**$ 4,908**	$ 3,206

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

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

(3) Includes cash consideration of $771 million and the settlement of long-term debt of $183 million assumed in the acquisition of Storm in the fourth quarter of 2021.

(4) Includes cash consideration of $111 million and the settlement of long-term debt of $397 million assumed in the acquisition of Painted Pony Energy Ltd. ("Painted Pony") in the fourth quarter of 2020.

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

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

Net capital expenditures for the year ended December 31, 2021 were $4,908 million compared with $3,206 million for the year ended December 31, 2020. Net capital expenditures for the fourth quarter of 2021 were $1,804 million compared with $1,176 million for the fourth quarter of 2020 and $1,011 million for the third quarter of 2021.

On December 17, 2021, the Company completed the acquisition of all the issued and outstanding common shares of Storm for total cash consideration of approximately $771 million. At closing, the acquisition also included the assumption of long-term debt of approximately $183 million. Storm is involved in the exploration for and development of natural gas and natural gas liquids in the Montney region of British Columbia.

During the year ended December 31, 2021, the Company also completed a number of other opportunistic acquisitions. Two acquisitions consisted of natural gas assets located in the Montney region of British Columbia. A third acquisition consisted of a net carried interest on an existing oil sands lease held by the Company, from which all Horizon production volumes are derived. Total cash consideration paid for these acquisitions was approximately $450 million.

2022 Capital Budget

On January 11, 2022, the Company announced its 2022 base capital budget targeted at approximately $3,645 million. The budget also includes incremental strategic growth capital of approximately $700 million that targets to add future production and capacity in the Company's long life low decline thermal in situ and Oil Sands Mining and Upgrading assets.

The 2022 capital budget constitutes forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Drilling Activity [1]

	Three Months Ended			Year Ended	
(number of net wells)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Net successful natural gas wells	**9**	9	9	**49**	30
Net successful crude oil wells [2]	**22**	56	5	**149**	42
Dry wells	**—**	1	—	**1**	—
Stratigraphic test / service wells	**57**	7	—	**393**	372
Total	**88**	73	14	**592**	444
Success rate (excluding stratigraphic test / service wells)	**100%**	98%	100%	**99%**	100%

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

(2) Includes bitumen wells.

North America

During the fourth quarter of 2021, the Company drilled 9 net natural gas wells, 11 net primary heavy crude oil wells, 1 net bitumen (thermal oil) well and 9 net light crude oil wells.

North Sea

During the fourth quarter of 2021, the Company drilled 1.0 net light crude oil well in the North Sea.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Dec 31 2021**		Sep 30 2021		Dec 31 2020
Adjusted working capital (1)	**$**	**(480)**	$	423	$	626
Long-term debt, net (2)	**$**	**13,950**	$	15,880	$	21,269
Shareholders' equity	**$**	**36,945**	$	35,526	$	32,380
Debt to book capitalization (2)		**27.4%**		30.9%		39.6%
After-tax return on average capital employed (3)		**15.6%**		12.1%		0.2%

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

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

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

As at December 31, 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 fourth quarter of 2021, the Company extended both of its $2,425 million revolving credit facilities originally maturing June 2022 and June 2023, to June 2024 and June 2025, respectively and increased each by $70 million. In accordance with the terms of the extension, and by mutual agreement, $70 million of the original revolving credit facilities were not extended and will mature upon the original maturity date of June 2022 and June 2023, respectively. 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.
  - 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 fourth quarter of 2021, the facility was fully repaid. The facility was amended to allow for a re-draw of the full $1,000 million until March 31, 2022.
  - 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. During the fourth quarter of 2021, the Company repaid an additional $1,000 million on the facility, reducing the outstanding balance to $1,150 million.

- In July 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- In July 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- 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, SOFR, US base rate or Canadian prime rate.
- The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

As at December 31, 2021, the Company had undrawn bank credit facilities of $6,098 million. Including cash and cash equivalents and short-term investments, the Company had approximately $7,151 million in liquidity. Additionally, the Company had in place fully drawn term credit facilities of $1,150 million. The Company also has certain other dedicated credit facilities supporting letters of credit.

As at December 31, 2021, the Company had total US dollar denominated debt with a carrying amount of $11,581 million (US$9,151 million), before transaction costs and original issue discounts. This included $1,836 million (US$1,451 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$901 million). The fixed repayment amount of these hedging instruments is $1,805 million, resulting in a notional reduction of the carrying amount of the Company’s US dollar denominated debt by approximately $31 million to $11,550 million as at December 31, 2021.

Net long-term debt was $13,950 million at December 31, 2021, resulting in a debt to book capitalization ratio of 27.4% (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 December 31, 2021 are discussed in note 8 to the financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 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 December 31, 2021 are discussed in note 15 to the financial statements.

As at December 31, 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	$	2,906	$	3,251	$	7,624
Other long-term liabilities [2]	$	282	$	181	$	430	$	824
Interest and other financing expense [3]	$	650	$	583	$	1,503	$	3,971

(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, $185 million; one to less than two years, $149 million; two to less than five years, $426 million; and thereafter, $824 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 December 31, 2021.

Share Capital

As at December 31, 2021, there were 1,168,369,000 common shares outstanding (December 31, 2020 – 1,183,866,000 common shares) and 38,327,000 stock options outstanding. As at March 1, 2022, the Company had 1,163,204,000 common shares outstanding and 37,112,000 stock options outstanding.

On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share, beginning with the dividend payable on April 5, 2022. On November 3, 2021, the Board of Directors approved a 25% increase in the quarterly dividend to $0.5875 per common share, from $0.47 per common share. On March 3, 2021, the Board of Directors approved an 11% increase in the quarterly dividend to $0.47 per common share, from $0.425 per common share. On March 4, 2020, the Board of Directors approved a 13% increase in the quarterly dividend to $0.425 per common share, from $0.375 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 ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 59,278,474 common shares, over a 12-month period commencing March 11, 2021 and ending March 10, 2022.

For the year ended December 31, 2021, the Company purchased 33,644,400 common shares at a weighted average price of $46.98 per common share for a total cost of $1,581 million. Retained earnings were reduced by $1,297 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2021, the Company purchased 10,500,000 common shares at a weighted average price of $64.79 per common share for a total cost of $680 million.

On March 2, 2022, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of a Normal Course Issuer Bid, up to 10% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2021:

($ millions)	2022	2023	2024	2025	2026	Thereafter
Product transportation and processing [1] [2]	$ 967	$ 1,107	$ 914	$ 870	$ 816	$ 10,028
North West Redwater Partnership service toll [3]	$ 122	$ 123	$ 121	$ 119	$ 97	$ 3,671
Offshore vessels and equipment	$ 62	$ —	$ —	$ —	$ —	$ —
Field equipment and power	$ 25	$ 21	$ 21	$ 21	$ 21	$ 225
Other	$ 37	$ 27	$ 22	$ 20	$ 15	$ —

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

(2) The acquisition of Storm in the fourth quarter of 2021 included approximately $298 million of product transportation and processing commitments.

(3) 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 $1,486 million of interest payable over the 40-year tolling period, ending in 2058.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

REGULATORY DEVELOPMENTS

On May 27, 2021, the Canadian Securities Administrators ("CSA") announced the adoption of 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 apply to the Company's MD&A and certain other disclosure documents for the three months and year ended December 31, 2021.

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 months and year ended December 31, 2021, COVID-19 continued to have an impact on the global economy, including the oil and gas industry. Business conditions in the fourth quarter of 2021 continued to reflect the market uncertainty associated with COVID-19. 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 year ended December 31, 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.

NON-GAAP AND OTHER FINANCIAL MEASURES

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

Adjusted Net Earnings (Loss) from Operations

Adjusted net earnings (loss) from operations is a non-GAAP financial measure that adjusts net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), for non-operating items (after-tax). 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. A reconciliation for adjusted net earnings (loss) from operations is presented below.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Net earnings (loss)	**$ 2,534**	$ 2,202	$ 749	**$ 7,664**	$ (435)
Share-based compensation, net of tax (1)	**183**	54	117	**495**	(86)
Unrealized risk management loss (gain), net of tax (2)	**10**	(15)	(16)	**16**	(31)
Unrealized foreign exchange (gain) loss, net of tax (3)	**(79)**	197	(534)	**(205)**	(116)
Realized foreign exchange loss (gain), net of tax (4)	**—**	118	—	**118**	(166)
Gain on acquisitions, net of tax (5)	**—**	(478)	(217)	**(478)**	(217)
(Gain) loss from investments, net of tax (6)	**(3)**	35	(33)	**(132)**	185
Other, net of tax (7)	**(19)**	(18)	110	**(58)**	110
Non-operating items (after-tax)	**92**	(107)	(573)	**(244)**	(321)
Adjusted net earnings (loss) from operations	**$ 2,626**	$ 2,095	$ 176	**$ 7,420**	$ (756)

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings (loss). Pre-tax share-based compensation for the three months ended December 31, 2021 was an expense of $191 million (three months ended September 30, 2021 – $57 million expense, December 31, 2020 – $123 million expense; year ended December 31, 2021 – $514 million expense, December 31, 2020 – $82 million recovery).

(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. Pre-tax unrealized risk management loss for the three months ended December 31, 2021 was $8 million (three months ended September 30, 2021 – $19 million gain, December 31, 2020 – $21 million gain; year ended December 31, 2021 – $19 million loss, December 31, 2020 – $39 million gain).

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

(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. 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. There was net zero tax impact on the settlement.

(5) During the third quarter of 2021, the Company completed two acquisitions resulting in a pre- and after-tax gain of $478 million. During the fourth quarter of 2020, the Company recognized a pre- and after-tax gain of $217 million related to the acquisition of Painted Pony.

(6) The Company's investments in PrairieSky and 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). There is net zero tax impact on these (gains) losses from investment.

(7) For the year ended December 31, 2021, the Company recognized the impact of government grant income under the provincial well-site rehabilitation programs of $75 million ($58 million after-tax) including $25 million ($19 million after-tax) for the fourth quarter of 2021 (September 30, 2021 – $23 million, $18 million after-tax). During the three months and year ended December 31, 2020, the Company recognized a provision in transportation, blending and feedstock expense of $143 million ($110 million after-tax) relating to the Keystone XL pipeline project.

Adjusted Funds Flow

Adjusted funds flow is a non-GAAP financial measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets. The Company considers adjusted funds flow a key measure in evaluating its performance, as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. A reconciliation for adjusted funds flow, from cash flows from operating activities is presented below.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Cash flows from operating activities	**$ 4,712**	$ 4,290	$ 1,270	**$ 14,478**	$ 4,714
Net change in non-cash working capital	**(420)**	(691)	394	**(964)**	166
Abandonment expenditures, net (1)	**67**	54	52	**232**	249
Movements in other long-term assets (2)	**(21)**	(19)	(8)	**(13)**	71
Adjusted funds flow	**$ 4,338**	$ 3,634	$ 1,708	**$ 13,733**	$ 5,200

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

(2) Includes the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to NWRP and prepaid cost of service tolls.

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

Adjusted net earnings (loss) from operations and adjusted funds flow, per share (basic and diluted), are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 14 to the financial statements.

Abandonment Expenditures, net

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Abandonment expenditures	**$ 92**	$ 77	$ 52	**$ 307**	$ 249
Government grants for abandonment expenditures	**(25)**	(23)	—	**(75)**	—
Abandonment expenditures, net	**$ 67**	$ 54	$ 52	**$ 232**	$ 249

Netback

Netback is a non-GAAP ratio that represents net cash flows provided from core activities after the impact of all costs associated with bringing a product to market, on a per unit basis. The Company considers netback a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. Refer to the "Operating Highlights – Exploration and Production" section of this MD&A for the netback calculations on a per unit basis for crude oil and NGLs, natural gas and on a total barrels of oil equivalent basis.

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

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

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

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

	Three Months Ended			Year Ended	
($ millions, except bbl/d and $/bbl)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Crude oil and NGLs (bbl/d)					
North America	**490,448**	448,948	476,240	**471,331**	465,073
North Sea	**21,360**	16,028	20,100	**18,942**	22,852
Offshore Africa	**5,624**	19,402	19,961	**13,452**	17,017
Sales volumes	**517,432**	484,378	516,301	**503,725**	504,942
Crude oil and NGLs sales [(1)]	**$ 4,667**	$ 3,810	$ 2,568	**$ 15,505**	$ 8,215
Less: Blending costs [(2)]	**1,202**	777	641	**3,792**	2,321
Realized crude oil and NGLs sales	**$ 3,465**	$ 3,033	$ 1,927	**$ 11,713**	$ 5,894
Realized price ($/bbl)	**$ 72.81**	$ 68.06	$ 40.56	**$ 63.71**	$ 31.90

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

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

	Three Months Ended			Year Ended	
($ millions, except BOE/d and $/BOE)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Barrels of oil equivalent (BOE/d)					
North America	**797,185**	731,962	746,684	**751,330**	706,799
North Sea	**21,940**	16,427	20,817	**19,512**	24,805
Offshore Africa	**7,781**	20,652	22,807	**15,385**	19,517
Sales volumes	**826,906**	769,041	790,308	**786,227**	751,121
Barrels of oil equivalent sales [(1)]	**$ 5,581**	$ 4,460	$ 3,013	**$ 18,025**	$ 9,511
Less: Blending costs [(2)]	**1,202**	777	641	**3,792**	2,321
Less: Sulphur (income) expense	**(12)**	(3)	—	**(21)**	4
Realized barrels of oil equivalent sales	**$ 4,391**	$ 3,686	$ 2,372	**$ 14,254**	$ 7,186
Realized price ($/BOE)	**$ 57.72**	$ 52.09	$ 32.61	**$ 49.67**	$ 26.15

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

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

Transportation – Exploration and Production

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

($ millions, except $ per unit amounts)	Three Months Ended **Dec 31 2021**	Three Months Ended Sep 30 2021	Three Months Ended Dec 31 2020	Year Ended **Dec 31 2021**	Year Ended Dec 31 2020
Transportation, blending and feedstock (1)	**$ 1,461**	$ 1,025	$ 1,028	**$ 4,780**	$ 3,409
Less: Blending costs	**1,202**	777	641	**3,792**	2,321
Less: Other (2)	**—**	—	143	**—**	143
Transportation	**$ 259**	$ 248	$ 244	**$ 988**	$ 945
Transportation ($/BOE)	**$ 3.40**	$ 3.50	$ 3.37	**$ 3.44**	$ 3.44
Amounts attributed to crude oil and NGLs	**$ 187**	$ 178	$ 181	**$ 710**	$ 711
Transportation ($/bbl)	**$ 3.93**	$ 4.00	$ 3.81	**$ 3.86**	$ 3.85
Amounts attributed to natural gas	**$ 72**	$ 70	$ 63	**$ 278**	$ 234
Transportation ($/Mcf)	**$ 0.42**	$ 0.44	$ 0.42	**$ 0.45**	$ 0.43

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

(2) Transportation excludes the impact of a $143 million provision recognized in the fourth quarter of 2020, relating to the Keystone XL pipeline project.

North America – Realized Product Prices & Royalties

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

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

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

($ millions, except $/bbl and royalty rates)	Three Months Ended **Dec 31 2021**	Three Months Ended Sep 30 2021	Three Months Ended Dec 31 2020	Year Ended **Dec 31 2021**	Year Ended Dec 31 2020
Crude oil and NGLs sales (1)	**$ 4,431**	$ 3,506	$ 2,374	**$ 14,478**	$ 7,480
Less: Blending costs (2)	**1,202**	777	641	**3,792**	2,321
Realized crude oil and NGLs sales	**$ 3,229**	$ 2,729	$ 1,733	**$ 10,686**	$ 5,159
Realized crude oil and NGLs prices ($/bbl)	**$ 71.57**	$ 66.03	$ 39.54	**$ 62.10**	$ 30.31
Crude oil and NGLs royalties (3)	**$ 506**	$ 414	$ 155	**$ 1,558**	$ 464
Crude oil and NGLs royalty rates	**16%**	15%	9%	**15%**	9%

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

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

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

Realized Product Prices and Transportation – Oil Sands Mining and Upgrading

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

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

Reconciliations for Oil Sands Mining and Upgrading realized SCO sales and transportation and the calculations for realized SCO sales price and transportation are presented below.

	Three Months Ended			Year Ended	
($ millions, except for bbl/d and $/bbl)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
SCO sales volumes (bbl/d)	**483,972**	467,772	423,438	**447,230**	415,741
Crude oil and NGLs sales [(1)]	**$ 4,408**	$ 3,848	$ 2,078	**$ 14,033**	$ 7,389
Less: blending and feedstock costs	**468**	339	187	**1,309**	695
Realized SCO sales	**$ 3,940**	$ 3,509	$ 1,891	**$ 12,724**	$ 6,694
Realized SCO sales price ($/bbl)	**$ 88.48**	$ 81.54	$ 48.56	**$ 77.95**	$ 43.98
Transportation, blending and feedstock [(2)]	**$ 527**	$ 387	$ 240	**$ 1,505**	$ 881
Less: blending and feedstock costs	**468**	339	187	**1,309**	695
Transportation	**$ 59**	$ 48	$ 53	**$ 196**	$ 186
Transportation ($/bbl)	**$ 1.33**	$ 1.14	$ 1.36	**$ 1.21**	$ 1.23

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

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

Net Capital Expenditures

Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, proceeds from investment, 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. A reconciliation of net capital expenditures is presented below.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2021**	Sep 30 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Cash flows used in investing activities	**$ 1,615**	$ 721	$ 624	**$ 3,703**	$ 2,819
Net change in non-cash working capital	**(61)**	108	(21)	**107**	(383)
Proceeds from investment	**—**	128	—	**128**	—
Repayment of NWRP subordinated debt advances	**—**	—	124	**555**	124
Capital expenditures	**1,554**	957	727	**4,493**	2,560
Abandonment expenditures, net [(1)]	**67**	54	52	**232**	249
Settlement of long-term debt acquired [(2)]	**183**	—	397	**183**	397
Net capital expenditures	**$ 1,804**	$ 1,011	$ 1,176	**$ 4,908**	$ 3,206

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

(2) Relates to the settlement of long-term debt assumed in the acquisition of Storm in the fourth quarter of 2021 and Painted Pony in the fourth quarter of 2020.

Liquidity

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

($ millions)		**Dec 31 2021**		Sep 30 2021		Dec 31 2020
Undrawn bank credit facilities	**$**	**6,098**	$	4,959	$	4,958
Cash and cash equivalents		**744**		894		184
Investments		**309**		306		305
Liquidity	**$**	**7,151**	$	6,159	$	5,447

Long-term Debt, net

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

Debt to Book Capitalization

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

After-Tax Return on Average Capital Employed

After-tax return on average capital employed as defined by the Company is a non-GAAP ratio. The ratio is calculated as net earnings (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. The Company considers this ratio a key measure in evaluating the Company's ability to generate profit and the efficiency with which it employs capital. A reconciliation of the Company's after-tax return on average capital employed is presented below.

($ millions, except ratios)		**Dec 31 2021**		Sep 30 2021		Dec 31 2020
Interest adjusted after-tax return:						
Net earnings (loss), 12 months trailing	**$**	**7,664**	$	5,879	$	(435)
Interest and other financing expense, net of tax, 12 months trailing (1)		**547**		552		571
Interest adjusted after-tax return	**$**	**8,211**	$	6,431	$	136
12 months average current portion long-term debt (2)	**$**	**1,483**	$	1,449	$	1,842
12 months average long-term debt (2)		**16,769**		18,240		20,162
12 months average common shareholders' equity (2)		**34,458**		33,502		33,026
12 months average capital employed	**$**	**52,710**	$	53,191	$	55,030
After-tax return on average capital employed		**15.6%**		12.1%		0.2%

(1) The blended tax rate on interest was 23% for December 31, 2021, 23% for September 30, 2021, and 24% for December 31, 2020.

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

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note		**Dec 31 2021**		Dec 31 2020
ASSETS					
Current assets					
Cash and cash equivalents		**$**	**744**	$	184
Accounts receivable			**3,111**		2,190
Current income taxes receivable			**—**		309
Inventory			**1,548**		1,060
Prepaids and other			**195**		231
Investments	6		**309**		305
Current portion of other long-term assets	7		**35**		82
			5,942		4,361
Exploration and evaluation assets	3		**2,250**		2,436
Property, plant and equipment	4		**66,400**		65,752
Lease assets	5		**1,508**		1,645
Other long-term assets	7		**565**		1,082
		$	**76,665**	$	75,276
LIABILITIES					
Current liabilities					
Accounts payable		**$**	**803**	$	667
Accrued liabilities			**3,064**		2,346
Current income taxes payable			**1,607**		—
Current portion of long-term debt	8		**1,000**		1,343
Current portion of other long-term liabilities	5,9		**948**		722
			7,422		5,078
Long-term debt	8		**13,694**		20,110
Other long-term liabilities	5,9		**8,384**		7,564
Deferred income taxes			**10,220**		10,144
			39,720		42,896
SHAREHOLDERS' EQUITY					
Share capital	11		**10,168**		9,606
Retained earnings			**26,778**		22,766
Accumulated other comprehensive (loss) income	12		**(1)**		8
			36,945		32,380
		$	**76,665**	$	75,276

Commitments and contingencies (note 16).

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

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Dec 31 2021**	Three Months Ended Dec 31 2020	Year Ended **Dec 31 2021**	Year Ended Dec 31 2020
Product sales	17	**$ 10,190**	$ 5,219	**$ 32,854**	$ 17,491
Less: royalties		**(977)**	(201)	**(2,797)**	(598)
Revenue		**9,213**	5,018	**30,057**	16,893
Expenses					
Production		**1,869**	1,631	**7,152**	6,280
Transportation, blending and feedstock		**2,065**	1,318	**6,604**	4,498
Depletion, depreciation and amortization	4,5	**1,473**	1,615	**5,724**	6,046
Administration		**97**	107	**366**	391
Share-based compensation	9	**191**	123	**514**	(82)
Asset retirement obligation accretion	9	**46**	51	**185**	205
Interest and other financing expense		**171**	177	**711**	756
Risk management activities	15	**2**	2	**36**	(7)
Foreign exchange gain		**(106)**	(513)	**(127)**	(275)
Gain on acquisitions	4	**—**	(217)	**(478)**	(217)
Income from North West Redwater Partnership	7	**—**	—	**(400)**	—
(Gain) loss from investments	6	**(5)**	(35)	**(141)**	171
		5,803	4,259	**20,146**	17,766
Earnings (loss) before taxes		**3,410**	759	**9,911**	(873)
Current income tax expense (recovery)	10	**683**	35	**1,848**	(257)
Deferred income tax expense (recovery)	10	**193**	(25)	**399**	(181)
Net earnings (loss)		**$ 2,534**	$ 749	**$ 7,664**	$ (435)
Net earnings (loss) per common share					
Basic	14	**$ 2.16**	$ 0.63	**$ 6.49**	$ (0.37)
Diluted	14	**$ 2.14**	$ 0.63	**$ 6.46**	$ (0.37)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended **Dec 31 2021**	Three Months Ended Dec 31 2020	Year Ended **Dec 31 2021**	Year Ended Dec 31 2020
Net earnings (loss)	**$ 2,534**	$ 749	**$ 7,664**	$ (435)
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 – $nil) – three months ended; $2 million (2020 – $2 million) – year ended	**(19)**	(4)	**15**	13
Reclassification to net earnings (loss), net of taxes of $nil (2020 – $nil) – three months ended; $1 million (2020 – $2 million) – year ended	**1**	(2)	**(7)**	(15)
	(18)	(6)	**8**	(2)
Foreign currency translation adjustment				
Translation of net investment	**(20)**	(110)	**(17)**	(24)
Other comprehensive loss, net of taxes	**(38)**	(116)	**(9)**	(26)
Comprehensive income (loss)	**$ 2,496**	$ 633	**$ 7,655**	$ (461)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended **Dec 31 2021**	Dec 31 2020
Share capital	11		
Balance – beginning of year		**$ 9,606**	$ 9,533
Issued upon exercise of stock options		**707**	108
Previously recognized liability on stock options exercised for common shares		**139**	21
Purchase of common shares under Normal Course Issuer Bid		**(284)**	(56)
Balance – end of year		**10,168**	9,606
Retained earnings			
Balance – beginning of year		**22,766**	25,424
Net earnings (loss)		**7,664**	(435)
Dividends on common shares	11	**(2,355)**	(2,008)
Purchase of common shares under Normal Course Issuer Bid	11	**(1,297)**	(215)
Balance – end of year		**26,778**	22,766
Accumulated other comprehensive (loss) income	12		
Balance – beginning of year		**8**	34
Other comprehensive loss, net of taxes		**(9)**	(26)
Balance – end of year		**(1)**	8
Shareholders' equity		**$ 36,945**	$ 32,380

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Dec 31 2021**	Three Months Ended Dec 31 2020	Year Ended **Dec 31 2021**	Year Ended Dec 31 2020
Operating activities					
Net earnings (loss)		**$ 2,534**	$ 749	**$ 7,664**	$ (435)
Non-cash items					
Depletion, depreciation and amortization		**1,473**	1,615	**5,724**	6,046
Share-based compensation		**191**	123	**514**	(82)
Asset retirement obligation accretion		**46**	51	**185**	205
Unrealized risk management loss (gain)		**8**	(21)	**19**	(39)
Unrealized foreign exchange gain		**(79)**	(534)	**(205)**	(116)
Gain on acquisitions	4	**—**	(217)	**(478)**	(217)
(Gain) loss from investments	6	**(3)**	(33)	**(132)**	185
Deferred income tax expense (recovery)		**193**	(25)	**399**	(181)
Realized foreign exchange loss (gain)	8	**—**	—	**118**	(166)
Other		**21**	8	**13**	(71)
Abandonment expenditures		**(92)**	(52)	**(307)**	(249)
Net change in non-cash working capital		**420**	(394)	**964**	(166)
Cash flows from operating activities		**4,712**	1,270	**14,478**	4,714
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net	8	**(1,979)**	(563)	**(6,151)**	338
Issue (repayment) of medium-term notes	8	**—**	800	**—**	(1,100)
(Repayment) issue of US dollar debt securities	8	**—**	—	**(628)**	1,481
Settlement of long-term debt acquired	4	**(183)**	(397)	**(183)**	(397)
Proceeds on settlement of cross currency swaps		**—**	—	**—**	166
Payment of lease liabilities	5,9	**(55)**	(47)	**(209)**	(225)
Issue of common shares on exercise of stock options	11	**360**	72	**707**	108
Dividends on common shares		**(552)**	(502)	**(2,170)**	(1,950)
Purchase of common shares under Normal Course Issuer Bid	11	**(838)**	—	**(1,581)**	(271)
Cash flows used in financing activities		**(3,247)**	(637)	**(10,215)**	(1,850)
Investing activities					
Net proceeds (expenditures) on exploration and evaluation assets	3,17	**4**	(8)	**(1)**	(5)
Net expenditures on property, plant and equipment	4,17	**(1,558)**	(719)	**(4,492)**	(2,555)
Proceeds from investment	6	**—**	—	**128**	—
Repayment of North West Redwater Partnership subordinated debt advances	7	**—**	124	**555**	124
Net change in non-cash working capital		**(61)**	(21)	**107**	(383)
Cash flows used in investing activities		**(1,615)**	(624)	**(3,703)**	(2,819)
(Decrease) increase in cash and cash equivalents		**(150)**	9	**560**	45
Cash and cash equivalents – beginning of period		**894**	175	**184**	139
Cash and cash equivalents – end of period		**$ 744**	$ 184	**$ 744**	$ 184
Interest paid on long-term debt, net		**$ 122**	$ 147	**$ 672**	$ 745
Income taxes paid (received), net		**$ 32**	$ —	**$ (62)**	$ (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 months and year ended December 31, 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 fourth quarter of 2021 continued to reflect the market uncertainty associated with COVID-19. 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 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/Acquisitions	**30**	**—**	**8**	**—**	**38**
Transfers to property, plant and equipment	**(73)**	**—**	**—**	**(150)**	**(223)**
Derecognitions and other	**(1)**	**—**	**—**	**—**	**(1)**
At December 31, 2021	**$ 2,057**	**$ —**	**$ 91**	**$ 102**	**$ 2,250**

On December 17, 2021, the Company completed the acquisition of all the issued and outstanding common shares of Storm Resources Ltd. ("Storm") for total cash consideration of $771 million, including $13 million of exploration and evaluation assets (note 4).

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/Acquisitions	**4,146**	**208**	**48**	**1,526**	**9**	**23**	**5,960**
Transfers from E&E assets	**73**	**—**	**—**	**150**	**—**	**—**	**223**
Derecognitions and other [1]	**(382)**	**3**	**—**	**(530)**	**—**	**—**	**(909)**
Foreign exchange adjustments and other	**—**	**(56)**	**(31)**	**—**	**—**	**—**	**(87)**
At December 31, 2021	**$ 77,834**	**$ 7,438**	**$ 3,980**	**$ 46,856**	**$ 466**	**$ 508**	**$ 137,082**
Accumulated depletion and depreciation							
At December 31, 2020	$ 49,641	$ 5,853	$ 2,822	$ 7,289	$ 168	$ 370	$ 66,143
Expense	**3,468**	**149**	**118**	**1,733**	**15**	**25**	**5,508**
Derecognitions and other [1]	**(382)**	**3**	**—**	**(530)**	**—**	**—**	**(909)**
Foreign exchange adjustments and other	**5**	**(54)**	**(17)**	**7**	**—**	**(1)**	**(60)**
At December 31, 2021	**$ 52,732**	**$ 5,951**	**$ 2,923**	**$ 8,499**	**$ 183**	**$ 394**	**$ 70,682**
Net book value							
- at December 31, 2021	**$ 25,102**	**$ 1,487**	**$ 1,057**	**$ 38,357**	**$ 283**	**$ 114**	**$ 66,400**
- 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.

Acquisition of Storm Resources Limited

On December 17, 2021, the Company completed the acquisition of all the issued and outstanding common shares of Storm for total cash consideration of $771 million. Storm is involved in the exploration for and development of natural gas and natural gas liquids in the Montney region of British Columbia.

The acquisition has been accounted for using the acquisition method of accounting. The allocation of the purchase price was based on management's best estimates of the fair value of the assets acquired and liabilities assumed as of the acquisition date. The below amounts are estimates, and may be subject to change based on the receipt of new information.

The following provides a summary of the net assets acquired relating to the acquisition:

Property, plant and equipment	$	**1,114**
Exploration and evaluation assets		**13**
Working capital		**20**
Long-term debt		**(183)**
Asset retirement obligations		**(18)**
Other long-term liabilities		**(35)**
Deferred tax liability		**(140)**
Net assets acquired	$	**771**

In connection with the acquisition the Company assumed certain product transportation and processing commitments (note 16).

The impact of revenue and revenue, less production and transportation and blending expenses ("net operating income") generated by the acquisition from December 17, 2021 to December 31, 2021 was not significant. If the acquisition had been completed on January 1, 2021, the Company estimates that pro forma revenue would have increased by an additional $294 million and pro forma net operating income would have increased by an additional $205 million for the year ended December 31, 2021. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2021, or of future results. Pro forma results are based on available historical information for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

Other Acquisitions

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 operations consist 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.

As at December 31, 2021, the Company assessed the recoverability of its property, plant and equipment and its exploration and evaluation assets, and determined the carrying amounts of all of its cash generating units to be recoverable.

5. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2020	$ 1,038	$ 379	$ 128	$ 100	$ 1,645
Additions	**48**	**36**	**—**	**4**	**88**
Depreciation	**(110)**	**(57)**	**(27)**	**(22)**	**(216)**
Foreign exchange adjustments and other	**(2)**	**(4)**	**(2)**	**(1)**	**(9)**
At December 31, 2021	**$ 974**	**$ 354**	**$ 99**	**$ 81**	**$ 1,508**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at December 31, 2021 were as follows:

	Dec 31 2021	Dec 31 2020
Lease liabilities	**$ 1,584**	$ 1,690
Less: current portion	**185**	189
	$ 1,399	$ 1,501

Total cash outflows for leases for the three months ended December 31, 2021, including payments related to short-term leases not reported as lease assets, were $258 million (three months ended December 31, 2020 – $221 million; year ended December 31, 2021 – $1,089 million; year ended December 31, 2020 – $983 million). Interest expense on leases for the three months ended December 31, 2021 was $15 million (three months ended December 31, 2020 – $17 million; year ended December 31, 2021 – $62 million; year ended December 31, 2020 – $67 million).

6. INVESTMENTS

As at December 31, 2021, the Company had the following investments:

	Dec 31 2021	Dec 31 2020
Investment in PrairieSky Royalty Ltd.	**$ 309**	$ 228
Investment in Inter Pipeline Ltd.	**—**	77
	$ 309	$ 305

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

	Three Months Ended		Year Ended	
	Dec 31 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
(Gain) loss from investments	**$ (3)**	$ (33)	**$ (132)**	$ 185
Dividend income	**(2)**	(2)	**(9)**	(14)
	$ (5)	$ (35)	**$ (141)**	$ 171

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 December 31, 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 December 31, 2021, the market price per common share was $13.63 (December 31, 2020 – $10.09).

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

		Dec 31 2021		Dec 31 2020
North West Redwater Partnership	**$**	**—**	$	555
Prepaid cost of service tolls		**157**		162
Risk management (note 15)		**140**		136
Long-term inventory		**126**		121
Other		**177**		190
		600		1,164
Less: current portion		**35**		82
	$	**565**	$	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. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period (note 16). Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 17).

On June 30, 2021, the equity partners together with the toll payers, agreed to optimize the structure of NWRP to better align the commercial interests of the equity partners and the toll payers (the "Optimization Transaction"). 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 December 31, 2021, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $562 million (December 31, 2020 – $153 million). For the three months ended December 31, 2021, the unrecognized share of the equity loss was $12 million (year ended December 31, 2021 – unrecognized equity loss of $9 million and partnership distributions of $400 million; three months ended December 31, 2020 – unrecognized equity income of $6 million; year ended December 31, 2020 – unrecognized equity loss of $94 million).

8. LONG-TERM DEBT

	Dec 31 2021	Dec 31 2020
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ —**	$ 1,614
Medium-term notes	**3,200**	3,200
	3,200	4,814
US dollar denominated debt, unsecured		
Bank credit facilities (December 31, 2021 – US$901 million; December 31, 2020 – US$3,953 million)	**1,140**	5,041
Commercial paper (December 31, 2021 – US$ nil; December 31, 2020 – US$426 million)	**—**	544
US dollar debt securities (December 31, 2021 – US$8,250 million; December 31, 2020 – US$8,750 million)	**10,441**	11,161
	11,581	16,746
Long-term debt before transaction costs and original issue discounts, net	**14,781**	21,560
Less: original issue discounts, net (1)	**15**	18
transaction costs (1) (2)	**72**	89
	14,694	21,453
Less: current portion of commercial paper	**—**	544
current portion of other long-term debt (1) (2)	**1,000**	799
	$ 13,694	$ 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 December 31, 2021, the Company had undrawn bank credit facilities of $6,098 million. Additionally, the Company had in place fully drawn term credit facilities of $1,150 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 $1,000 million term credit facility maturing February 2023;
- a $1,150 million non-revolving term credit facility maturing February 2023;
- a $2,495 million revolving syndicated credit facility, with $70 million maturing June 2022, and $2,425 million maturing June 2024;
- a $2,495 million revolving syndicated credit facility, with $70 million maturing June 2023, and $2,425 million maturing June 2025; 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, SOFR, US base rate or Canadian prime rate.

During the fourth quarter of 2021, the Company extended both of its $2,425 million revolving credit facilities originally maturing June 2022 and June 2023, to June 2024 and June 2025, respectively and increased each by $70 million. In accordance with the terms of the extension, and by mutual agreement, $70 million of the original revolving credit facilities were not extended and will mature upon the original maturity date of June 2022 and June 2023, respectively. 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.

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 fourth quarter of 2021, the facility was fully repaid. The facility was amended to allow for a re-draw of the full $1,000 million until March 31, 2022.

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. During the fourth quarter of 2021, the Company repaid an additional $1,000 million on the facility, reducing the outstanding balance to $1,150 million.

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 December 31, 2021 was 0.8% (December 31, 2020 – 1.1%), and on total long-term debt outstanding for the year ended December 31, 2021 was 3.5% (December 31, 2020 – 3.5%).

As at December 31, 2021, letters of credit and guarantees aggregating to $513 million were outstanding.

Medium-Term Notes

In July 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US Dollar Debt Securities

In July 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

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

	Dec 31 2021	Dec 31 2020
Asset retirement obligations	**$ 6,806**	$ 5,861
Lease liabilities (note 5)	**1,584**	1,690
Share-based compensation	**489**	160
Risk management (note 15)	**85**	160
Transportation and processing contracts	**241**	270
Other [1]	**127**	145
	9,332	8,286
Less: current portion	**948**	722
	$ 8,384	$ 7,564

(1) Includes $48 million (2020 – $72 million) related to the acquisition of the Joslyn oil sands project in 2018, payable in annual installments of $25 million.

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 4.0% (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:

	Dec 31 2021	Dec 31 2020
Balance – beginning of year	**$ 5,861**	$ 5,771
Liabilities incurred	**5**	5
Liabilities acquired, net	**76**	13
Liabilities settled	**(307)**	(249)
Asset retirement obligation accretion	**185**	205
Revision of cost and timing estimates	**1,716**	(134)
Change in discount rates	**(723)**	253
Foreign exchange adjustments	**(7)**	(3)
Balance – end of year	**6,806**	5,861
Less: current portion	**249**	184
	$ 6,557	$ 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.

	Dec 31 2021	Dec 31 2020
Balance – beginning of year	**$ 160**	$ 297
Share-based compensation expense (recovery)	**514**	(82)
Cash payment for stock options surrendered and PSUs vested	**(48)**	(39)
Transferred to common shares	**(139)**	(21)
Other	**2**	5
Balance – end of year	**489**	160
Less: current portion	**329**	119
	$ 160	$ 41

Included within share-based compensation liability as at December 31, 2021 was $90 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		Year Ended	
Expense (recovery)	**Dec 31 2021**	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Current corporate income tax – North America	**$ 691**	$ 42	**$ 1,841**	$ (245)
Current corporate income tax – North Sea	**(3)**	—	**7**	(4)
Current corporate income tax – Offshore Africa	**3**	5	**21**	17
Current PRT [(1)] – North Sea	**(12)**	(14)	**(34)**	(31)
Other taxes	**4**	2	**13**	6
Current income tax	**683**	35	**1,848**	(257)
Deferred income tax	**193**	(25)	**399**	(181)
Income tax	**$ 876**	$ 10	**$ 2,247**	$ (438)

(1) Petroleum Revenue Tax

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Year Ended Dec 31, 2021	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of year	**1,183,866**	**$ 9,606**
Issued upon exercise of stock options	**18,147**	**707**
Previously recognized liability on stock options exercised for common shares	**—**	**139**
Purchase of common shares under Normal Course Issuer Bid	**(33,644)**	**(284)**
Balance – end of year	**1,168,369**	**$ 10,168**

Dividend Policy

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

On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share, beginning with the dividend payable on April 5, 2022. On November 3, 2021, the Board of Directors approved a 25% increase in the quarterly dividend to $0.5875 per common share, from $0.47 per common share. On March 3, 2021, the Board of Directors approved an 11% increase in the quarterly dividend to $0.47 per common share, from $0.425 per common share. On March 4, 2020, the Board of Directors approved a 13% increase in the quarterly dividend to $0.425 per common share, from $0.375 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

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 ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 59,278,474 common shares, over a 12-month period commencing March 11, 2021 and ending March 10, 2022.

For the year ended December 31, 2021, the Company purchased 33,644,400 common shares at a weighted average price of $46.98 per common share for a total cost of $1,581 million. Retained earnings were reduced by $1,297 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2021, the Company purchased 10,500,000 common shares at a weighted average price of $64.79 per common share for a total cost of $680 million.

On March 2, 2022, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of a Normal Course Issuer Bid, up to 10% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding at December 31, 2021:

	Year Ended Dec 31, 2021		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of year	**48,656**	**$**	**37.53**
Granted	**12,547**	**$**	**34.39**
Exercised for common shares	**(18,147)**	**$**	**38.97**
Surrendered for cash settlement	**(1,324)**	**$**	**40.54**
Forfeited	**(3,405)**	**$**	**35.73**
Outstanding – end of year	**38,327**	**$**	**35.88**
Exercisable – end of year	**7,841**	**$**	**39.19**

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 (LOSS) INCOME

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

		Dec 31 2021		Dec 31 2020
Derivative financial instruments designated as cash flow hedges	**$**	**77**	$	69
Foreign currency translation adjustment		**(78)**		(61)
	$	**(1)**	$	8

13. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current long-term debt and long-term debt less cash and cash equivalents divided by the sum of the carrying value of shareholders' equity plus current long-term debt and long-term debt less cash and cash equivalents. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2021, the ratio was within the target range at 27.4%.

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

		Dec 31 2021		Dec 31 2020
Long-term debt	**$**	**14,694**	$	21,453
Less: cash and cash equivalents		**744**		184
Long-term debt, net	**$**	**13,950**	$	21,269
Total shareholders' equity	**$**	**36,945**	$	32,380
Debt to book capitalization		**27.4%**		39.6%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. At December 31, 2021, the Company was in compliance with this covenant.

14. NET EARNINGS (LOSS) PER COMMON SHARE

		Three Months Ended				Year Ended		
		Dec 31 2021		Dec 31 2020		**Dec 31 2021**		Dec 31 2020
Weighted average common shares outstanding – basic (thousands of shares)		**1,174,683**		1,181,968		**1,181,250**		1,181,768
Effect of dilutive stock options (thousands of shares)		**11,150**		924		**5,307**		—
Weighted average common shares outstanding – diluted (thousands of shares)		**1,185,833**		1,182,892		**1,186,557**		1,181,768
Net earnings (loss)	**$**	**2,534**	$	749	**$**	**7,664**	$	(435)
Net earnings (loss) per common share – basic	**$**	**2.16**	$	0.63	**$**	**6.49**	$	(0.37)
– diluted	**$**	**2.14**	$	0.63	**$**	**6.46**	$	(0.37)

15. FINANCIAL INSTRUMENTS

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

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

	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
Cash and cash equivalents	$ 184	$ —	$ —	$ —	$ 184
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)
	$ 2,929	$ 253	$ 28	$ (26,228)	$ (23,018)

(1) Includes $1,584 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:

	Dec 31, 2021			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3 (4)**
Investments (3)	**$ 309**	**$ 309**	**$ —**	**$ —**
Other long-term assets	**$ 140**	**$ —**	**$ 140**	**$ —**
Other long-term liabilities	**$ (133)**	**$ —**	**$ (85)**	**$ (48)**
Fixed rate long-term debt (6) (7)	**$ (13,554)**	**$ (15,420)**	**$ —**	**$ —**

	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)	**Dec 31 2021**	Dec 31 2020
Derivatives held for trading		
Natural gas (1)	**$ (41)**	$ (45)
Crude oil (1)	**(10)**	—
Foreign currency forward contracts	**(13)**	(7)
Cash flow hedges		
Foreign currency forward contracts	**(21)**	(108)
Cross currency swaps	**140**	136
	$ 55	$ (24)
Included within:		
Current portion of other long-term assets	**$ 5**	$ 5
Current portion of other long-term liabilities	**(72)**	(131)
Other long-term assets	**135**	131
Other long-term liabilities	**(13)**	(29)
	$ 55	$ (24)

(1) Commodity financial instruments acquired from Storm and Painted Pony in the fourth quarter of 2021 and 2020, respectively.

For the year ended December 31, 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)	**Dec 31 2021**	Dec 31 2020
Balance – beginning of year	**$ (24)**	$ 178
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities (1)	**(12)**	(32)
Foreign exchange	**82**	(168)
Other comprehensive income (loss)	**9**	(2)
Balance – end of year	**55**	(24)
Less: current portion	**(67)**	(126)
	$ 122	$ 102

(1) Includes the fair value movement in commodity financial instruments acquired from the date of acquisition.

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

	Three Months Ended		Year Ended	
	Dec 31 2021	Dec 31 2020	**Dec 31 2021**	Dec 31 2020
Net realized risk management (gain) loss	**$ (6)**	$ 23	**$ 17**	$ 32
Net unrealized risk management loss (gain)	**8**	(21)	**19**	(39)
	$ 2	$ 2	**$ 36**	$ (7)

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.

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 December 31, 2021, the Company had no significant interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. 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.

As at December 31, 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	Jan 2022	–	Mar 2038	US$550	1.170	6.25 %	5.76 %

The cross currency swap derivative financial instrument was designated as a hedge at December 31, 2021 and was classified as a cash flow hedge.

In addition to the cross currency swap contract noted above, at December 31, 2021, the Company had US$1,429 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$901 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 December 31, 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 December 31, 2021, the Company had net risk management assets of $140 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 December 31, 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	$ 803	$ —	$ —	$ —
Accrued liabilities	$ 3,064	$ —	$ —	$ —
Long-term debt (1)	$ 1,000	$ 2,906	$ 3,251	$ 7,624
Other long-term liabilities (2)	$ 282	$ 181	$ 430	$ 824
Interest and other financing expense (3)	$ 650	$ 583	$ 1,503	$ 3,971

(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, $185 million; one to less than two years, $149 million; two to less than five years, $426 million; and thereafter, $824 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 December 31, 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 December 31, 2021:

	2022	2023	2024	2025	2026	Thereafter
Product transportation and processing (1) (2)	$ 967	$ 1,107	$ 914	$ 870	$ 816	$ 10,028
North West Redwater Partnership service toll (3)	$ 122	$ 123	$ 121	$ 119	$ 97	$ 3,671
Offshore vessels and equipment	$ 62	$ —	$ —	$ —	$ —	$ —
Field equipment and power	$ 25	$ 21	$ 21	$ 21	$ 21	$ 225
Other	$ 37	$ 27	$ 22	$ 20	$ 15	$ —

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

(2) The acquisition of Storm in the fourth quarter of 2021 included approximately $298 million of product transportation and processing commitments (note 4).

(3) 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 $1,486 million of interest payable over the 40-year tolling period, ending in 2058 (note 7).

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

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

17. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2021	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Segmented product sales																
Crude oil and NGLs	**4,431**	2,374	**14,478**	7,480	**197**	104	**607**	417	**39**	90	**420**	318	**4,667**	2,568	**15,505**	8,215
Natural gas	**901**	434	**2,484**	1,242	**2**	1	**5**	12	**11**	10	**31**	42	**914**	445	**2,520**	1,296
Other income and revenue [1]	**38**	13	**119**	41	**(1)**	—	**(1)**	3	**1**	(4)	**7**	18	**38**	9	**125**	62
Total segmented product sales	**5,370**	2,821	**17,081**	8,763	**198**	105	**611**	432	**51**	96	**458**	378	**5,619**	3,022	**18,150**	9,573
Less: royalties	**(566)**	(173)	**(1,694)**	(503)	**—**	—	**(1)**	(1)	**(3)**	(5)	**(21)**	(16)	**(569)**	(178)	**(1,716)**	(520)
Segmented revenue	**4,804**	2,648	**15,387**	8,260	**198**	105	**610**	431	**48**	91	**437**	362	**5,050**	2,844	**16,434**	9,053
Segmented expenses																
Production	**794**	633	**2,963**	2,510	**130**	99	**383**	321	**14**	27	**91**	103	**938**	759	**3,437**	2,934
Transportation, blending and feedstock	**1,459**	1,026	**4,772**	3,393	**2**	2	**7**	15	**—**	—	**1**	1	**1,461**	1,028	**4,780**	3,409
Depletion, depreciation and amortization	**939**	1,017	**3,569**	3,780	**33**	61	**160**	277	**19**	54	**142**	190	**991**	1,132	**3,871**	4,247
Asset retirement obligation accretion	**25**	24	**101**	97	**5**	8	**21**	30	**2**	1	**6**	6	**32**	33	**128**	133
Risk management activities (commodity derivatives)	**(3)**	(29)	**29**	(20)	**—**	—	**—**	—	**—**	—	**—**	—	**(3)**	(29)	**29**	(20)
Gain on acquisitions	**—**	(217)	**(478)**	(217)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(217)	**(478)**	(217)
Income from North West Redwater Partnership	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**3,214**	2,454	**10,956**	9,543	**170**	170	**571**	643	**35**	82	**240**	300	**3,419**	2,706	**11,767**	10,486
Segmented earnings (loss)	**1,590**	194	**4,431**	(1,283)	**28**	(65)	**39**	(212)	**13**	9	**197**	62	**1,631**	138	**4,667**	(1,433)
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange gain																
(Gain) loss from investments																
Total non–segmented expenses																
Earnings (loss) before taxes																
Current income tax																
Deferred income tax																
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 Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2021	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Segmented product sales																
Crude oil and NGLs [2]	**4,408**	2,078	**14,033**	7,389	**17**	21	**78**	83	**(113)**	(75)	**(360)**	(108)	**8,979**	4,592	**29,256**	15,579
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**44**	51	**196**	182	**958**	496	**2,716**	1,478
Other income and revenue [1]	**18**	14	**73**	139	**200**	99	**681**	202	**(3)**	9	**3**	31	**253**	131	**882**	434
Total segmented product sales	**4,426**	2,092	**14,106**	7,528	**217**	120	**759**	285	**(72)**	(15)	**(161)**	105	**10,190**	5,219	**32,854**	17,491
Less: royalties	**(408)**	(23)	**(1,081)**	(78)	**—**	—	**—**	—	**—**	—	**—**	—	**(977)**	(201)	**(2,797)**	(598)
Segmented revenue	**4,018**	2,069	**13,025**	7,450	**217**	120	**759**	285	**(72)**	(15)	**(161)**	105	**9,213**	5,018	**30,057**	16,893
Segmented expenses																
Production	**871**	787	**3,414**	3,114	**42**	75	**234**	184	**18**	10	**67**	48	**1,869**	1,631	**7,152**	6,280
Transportation, blending and feedstock [2]	**527**	240	**1,505**	881	**165**	83	**550**	181	**(88)**	(33)	**(231)**	27	**2,065**	1,318	**6,604**	4,498
Depletion, depreciation and amortization	**478**	479	**1,838**	1,784	**4**	4	**15**	15	**—**	—	**—**	—	**1,473**	1,615	**5,724**	6,046
Asset retirement obligation accretion	**14**	18	**57**	72	**—**	—	**—**	—	**—**	—	**—**	—	**46**	51	**185**	205
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(3)**	(29)	**29**	(20)
Gain on acquisitions	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(217)	**(478)**	(217)
Income from North West Redwater Partnership	**—**	—	**—**	—	**—**	—	**(400)**	—	**—**	—	**—**	—	**—**	—	**(400)**	—
Total segmented expenses	**1,890**	1,524	**6,814**	5,851	**211**	162	**399**	380	**(70)**	(23)	**(164)**	75	**5,450**	4,369	**18,816**	16,792
Segmented earnings (loss)	**2,128**	545	**6,211**	1,599	**6**	(42)	**360**	(95)	**(2)**	8	**3**	30	**3,763**	649	**11,241**	101
Non–segmented expenses																
Administration													**97**	107	**366**	391
Share-based compensation													**191**	123	**514**	(82)
Interest and other financing expense													**171**	177	**711**	756
Risk management activities (other)													**5**	31	**7**	13
Foreign exchange gain													**(106)**	(513)	**(127)**	(275)
(Gain) loss from investments													**(5)**	(35)	**(141)**	171
Total non-segmented expenses													**353**	(110)	**1,330**	974
Earnings (loss) before taxes													**3,410**	759	**9,911**	(873)
Current income tax													**683**	35	**1,848**	(257)
Deferred income tax													**193**	(25)	**399**	(181)
Net earnings (loss)													**2,534**	749	**7,664**	(435)

(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)]

	Year Ended					
	Dec 31, 2021			Dec 31, 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	**$ (7)**	**$ (36)**	**$ (43)**	$ (7)	$ (150)	$ (157)
Offshore Africa	**8**	**—**	**8**	12	3	15
Oil Sands Mining and Upgrading	**—**	**(150)**	**(150)**	—	—	—
	1	**(186)**	**(185)**	5	(147)	(142)
Property, plant and equipment						
Exploration and Production						
North America [(3)] [(4)]	**2,486**	**1,351**	**3,837**	999	371	1,370
North Sea	**173**	**38**	**211**	122	(21)	101
Offshore Africa	**54**	**(6)**	**48**	87	7	94
	2,713	**1,383**	**4,096**	1,208	357	1,565
Oil Sands Mining and Upgrading [(5)]	**1,747**	**(601)**	**1,146**	1,323	(629)	694
Midstream and Refining	**9**	**—**	**9**	5	1	6
Head office	**23**	**—**	**23**	19	—	19
	4,492	**782**	**5,274**	2,555	(271)	2,284
	$ 4,493	**$ 596**	**$ 5,089**	$ 2,560	$ (418)	$ 2,142

(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) Includes cash consideration paid of $771 million for the acquisition of Storm in the fourth quarter of 2021.

(4) Includes cash consideration paid of $111 million for the acquisition of Painted Pony in the fourth quarter of 2020.

(5) 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

	Dec 31 2021	Dec 31 2020
Exploration and Production		
North America	**$ 30,645**	$ 29,094
North Sea	**1,561**	1,624
Offshore Africa	**1,332**	1,407
Other	**40**	81
Oil Sands Mining and Upgrading	**42,016**	41,567
Midstream and Refining	**886**	1,301
Head office	**185**	202
	$ 76,665	$ 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 December 31, 2021:	
Interest coverage (times)	
Net earnings [1]	14.9x
Adjusted funds flow [2]	22.9x

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

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

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CORPORATE INFORMATION

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CNR International (U.K.) Limited
Aberdeen, Scotland

David. B. Whitehouse
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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