FOURTH QUARTER REPORT

YEAR ENDED DECEMBER 31, 2020 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2020 FOURTH QUARTER AND YEAR END RESULTS

Commenting on the Company's 2020 results, Tim McKay, President of Canadian Natural stated "The impact of the COVID-19 pandemic effected the very way we conducted our lives and the way we operated our businesses. Through the year we took protocols to protect our stakeholders and would like to thank our employees, contractors, suppliers and shareholders for their support through this challenging year.

Despite the challenges of COVID-19 in 2020, the Company had a strong year operationally and financially as the Company's effective and efficient operations and long life low decline asset base proved their robustness in this challenging year. We were nimble in 2020, quickly lowering capital with minimal impact to annual production as we stayed within the Company's original production guidance range, effectively managing through a volatile commodity price environment and low crude oil demand. This was achieved through the commitment and hard work of our employees, who were rewarded with no economic layoffs due to the impacts of COVID-19. In 2020 the Company generated strong adjusted funds flow while effectively allocating to the Company's four pillars of capital allocation; balance sheet strength, returns to shareholders, resource value growth, and opportunistic acquisitions.

The Company achieved record annual corporate BOE production levels of approximately 1,164 MBOE/d, an increase of 6% or approximately 65,000 BOE/d over 2019 levels. Continued focus on effective and efficient operations and our culture of continuous improvement delivered strong operating cost reductions. As a result, record low annual operating costs of $20.46/bbl (US$15.25/bbl) of Synthetic Crude Oil ("SCO") produced were achieved at the Company's Oil Sands Mining and Upgrading segment, a decrease of $2.10/bbl. Our North America Exploration and Production ("E&P") liquids segment achieved significant operating cost reductions of $1.20/bbl or 10% from 2019 levels.

In 2020, Canadian Natural delivered top tier reserve replacement and finding, development and acquisition (“FD&A”) costs, reflecting the strength and depth of the asset base. Total proved reserves grew by 10% to 12.106 billion BOE, of which 58% are high value, zero decline, SCO reserves, resulting in a strong corporate reserve replacement of 361% in 2020. Total proved FD&A costs, including changes in future development costs, were strong at $4.46/BOE.

Environmental, Social and Governance ("ESG") performance remains a top priority and investments to improve our performance and reduce our environmental footprint continue. In 2020 we reduced our corporate Greenhouse Gas ("GHG") emission intensity by 18% and methane emissions by 28%, from 2016 levels. Our safety record is top tier, as corporate total recordable injury frequency ("TRIF") improved to 0.21 in 2020, a reduction of 58% from 2016 levels. Additionally in 2020, the Company reached significant environmental milestones, including the cumulative sequestration at our Quest facility of five million tonnes of CO_2 captured from the Scotford Upgrader and the cumulative planting of two and a half million trees at our Oil Sands Mining and Upgrading operations."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "The resilience and sustainability of our business model was evident in 2020 as annual adjusted funds flow was strong at over $5.3 billion, excluding the provision relating to the Keystone XL pipeline project. Excluding the Painted Pony acquisition costs and the Keystone XL provision, we completely covered our capital program, and dividend, generating approximately $690 million in free cash flow in 2020. Excluding Painted Pony acquisition costs, year end net debt would have decreased by approximately $80 million from 2019 year end levels. Our long life low decline asset base afforded the Company time to be patient in 2020 as we reduced capital, maintained our dividend increase, sustained a robust balance sheet with ample liquidity and opportunistically accessed the debt capital markets at attractive rates.

The sustainability of our free cash flow generation provides the Board of Directors confidence to increase our dividend by 11% to $1.88 per share annually, marking the 21st consecutive year of dividend increases representing a CAGR of 20% since inception. The 2021 capital budget of approximately $3.2 billion drives targeted annual production growth of approximately 61,000 BOE/d, at the mid-point of our production range, from 2020 levels and robust free cash flow generation. At the current 2021 annual strip pricing of approximately US$57 WTI per barrel, the Company targets to generate significant annual free cash flow of approximately $4.9 billion to $5.4 billion, after our capital program and increased dividend. As a result, our balance sheet is targeted to strengthen further in 2021, with year end debt to adjusted EBITDA targeted to improve to approximately 1.2x and debt to book capitalization targeted to improve to approximately 29%, at the mid-point of the targeted free cash flow range. Subsequent to year end, in March 2021 the Board of Directors authorized management, subject to acceptance by the TSX, to repurchase shares under a Normal Course Issuer Bid ("NCIB"), equal to options exercised throughout the coming year, in order to eliminate dilution for shareholders. Our strong financial position, unique long life low decline asset base and effective and efficient operations continue to generate long-term shareholder value."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Dec 31 2020	Three Months Ended Sep 30 2020	Three Months Ended Dec 31 2019	Year Ended Dec 31 2020	Year Ended Dec 31 2019
Net earnings (loss)	**$ 749**	$ 408	$ 597	**$ (435)**	$ 5,416
Per common share – basic	**$ 0.63**	$ 0.35	$ 0.50	**$ (0.37)**	$ 4.55
– diluted	**$ 0.63**	$ 0.35	$ 0.50	**$ (0.37)**	$ 4.54
Adjusted net earnings (loss) from operations (1)	**$ 176**	$ 135	$ 686	**$ (756)**	$ 3,795
Per common share – basic	**$ 0.15**	$ 0.11	$ 0.58	**$ (0.64)**	$ 3.19
– diluted	**$ 0.15**	$ 0.11	$ 0.58	**$ (0.64)**	$ 3.18
Cash flows from operating activities	**$ 1,270**	$ 2,070	$ 2,454	**$ 4,714**	$ 8,829
Adjusted funds flow (2)	**$ 1,708**	$ 1,740	$ 2,494	**$ 5,200**	$ 10,267
Per common share – basic	**$ 1.45**	$ 1.47	$ 2.11	**$ 4.40**	$ 8.62
– diluted	**$ 1.44**	$ 1.47	$ 2.10	**$ 4.40**	$ 8.61
Cash flows used in investing activities	**$ 624**	$ 643	$ 854	**$ 2,819**	$ 7,255
Net capital expenditures, excluding net acquisition costs (3)	**$ 655**	$ 771	$ 1,056	**$ 2,701**	$ 3,904
Net capital expenditures, including net acquisition costs (3)	**$ 1,176**	$ 771	$ 1,056	**$ 3,206**	$ 7,121
Daily production, before royalties					
Natural gas (MMcf/d)	**1,644**	1,362	1,455	**1,477**	1,491
Crude oil and NGLs (bbl/d)	**927,190**	884,342	913,782	**917,958**	850,393
Equivalent production (BOE/d) (4)	**1,201,198**	1,111,286	1,156,276	**1,164,136**	1,098,957

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure the Company utilizes to evaluate its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The derivation of this measure is discussed in the "Advisory" section of this press release.

(2) Adjusted funds flow is a non-GAAP measure the Company considers key to evaluate its performance as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The derivation of this measure is discussed in the "Advisory" section of this press release.

(3) Net capital expenditures is a non-GAAP measure the Company considers a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. For additional information and details, refer to the net capital expenditures table in the "Advisory" section of this press release.

(4) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, 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.

ANNUAL HIGHLIGHTS

- A net loss of $435 million and an adjusted net loss from operations of $756 million were realized in 2020.
- Cash flows from operating activities were $4,714 million in 2020.
- In 2020, the Company generated annual free cash flow of $692 million after dividend requirements and capital expenditures, before Painted Pony Energy Ltd. ("Painted Pony") acquisition costs, share repurchases and the provision relating to the Keystone XL pipeline project while managing through mandatory production volume curtailments, a volatile commodity price environment and lower crude oil demand, due to the global pandemic.
  - These results are a clear demonstration of the strength and resiliency of the Company's diverse, high quality, long life low decline asset base and effective and efficient operations that delivered a dividend increase in 2020 and excluding Painted Pony acquisition costs, would have decreased net debt from year ended 2019 levels.

- Canadian Natural generated strong annual adjusted funds flow of $5,343 million in 2020, excluding the provision relating to the Keystone XL pipeline project of $143 million, fully covering the Company's capital expenditures and dividend that was increased in March 2020.
  - Canadian Natural generated $692 million in free cash flow in 2020, after dividend payments of $1,950 million and net capital expenditures of $2,701 million, excluding Painted Pony acquisition costs, share repurchases and the provision relating to the Keystone XL pipeline project.
- Canadian Natural maintained a strong financial position in 2020 and would have reduced year ended net debt by $79 million from year ended 2019 levels when excluding Painted Pony acquisition costs.
  - Including Painted Pony acquisition costs, in the second half of 2020 the Company reduced absolute net debt by over $1.5 billion from June 30, 2020 levels.
  - As at December 31, 2020, the Company had undrawn revolving bank credit facilities of approximately $5.0 billion. Including cash and cash equivalents and short-term investments, the Company had significant liquidity of approximately $5.4 billion. At December 31, 2020, the Company had approximately $0.5 billion drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - In 2020, the Company repaid two medium-term notes totaling $1.9 billion.
  - In 2020, the Company successfully accessed both the Canadian and United States debt capital markets. Details are summarized as follows:
    - US dollar denominated debt securities were issued in Q2/20 totaling US$1.1 billion.
    - Canadian dollar denominated medium-term notes were issued in Q4/20 totaling $0.8 billion.
  - In 2020, the Company's $750 million non-revolving term credit facility, originally due February 2021 was increased by $250 million to $1,000 million and extended to February 2022. Subsequent to year end, in Q1/21, the Company has extended the facility to February 2023.
  - In Q2/20 the Company repaid $162.5 million on its $3,250 million non-revolving term loan, relating to the annual amortization requirement. Subsequent to year end, in Q1/21, the Company repaid a further $362.5 million on this facility, reducing the outstanding balance to $2,725 million, and satisfying the required annual amortization of $162.5 million originally due in June 2021.
- In 2020, the Company achieved record annual production volumes of 1,164,136 BOE/d, an increase of 6% from 2019 levels. The increase was primarily as a result of increased production from the thermal in situ and Oil Sands Mining and Upgrading segments and strong operations from the E&P liquids and natural gas segments.
  - Record annual corporate liquids production of 917,958 bbl/d was achieved in 2020, an increase of 8% from 2019 levels. The increase in 2020 was primarily as a result of the first full year of operatorship and improved performance at Jackfish, increased Kirby North production as the facility reached full capacity in June 2020 and high utilization rates and operational enhancements from the Company's Oil Sands Mining and Upgrading segment.
  - The Company effectively executed on its curtailment optimization strategy in 2020 by utilizing its high quality and flexible asset base to maximize production. The Government of Alberta curtailment program was suspended effective December 1, 2020.
- The Company's world class Oil Sands Mining and Upgrading assets averaged annual production of 417,351 bbl/d of SCO, an increase of 6% from 2019 levels. The increase from 2019 levels was as a result of high utilization rates and operational enhancements.
  - Record monthly production and high utilization was achieved at the Company's Oil Sands Mining and Upgrading assets in December 2020 of approximately 490,800 bbl/d of SCO, following the completion of planned turnarounds, increased capacity at the Scotford upgrader ("Scotford") and elimination of the mandatory Government of Alberta curtailment program.
  - Record low annual operating costs from the Company's Oil Sands Mining and Upgrading assets were achieved in 2020, averaging $20.46/bbl (US$15.25/bbl) of SCO. Operating costs decreased by 9% or $2.10/bbl from 2019 levels, driven by the Company's continued focus on effective and efficient operations, high reliability and operational enhancements.

- Canadian Natural's North America E&P annual liquids production averaged 460,443 bbl/d in 2020, an increase of 13% from 2019 levels. The increase was primarily as a result of increased thermal in situ production.
  - Canadian Natural's continued focus on effective and efficient operations was also demonstrated at the Company's North American E&P liquids, including thermal in situ operations, where annual operating costs of $11.21/bbl (US$8.36/bbl) were achieved in 2020, a decrease of 10%, or $1.20/bbl from 2019 levels.
- Canadian Natural's thermal in situ assets achieved record annual daily production in 2020, averaging 248,971 bbl/d, an increase of 48% over 2019 levels. The record daily production levels in 2020 were primarily as a result of a full year of operatorship of Jackfish and increased production at Kirby North.
  - Record monthly production was achieved at Jackfish in October 2020 reaching approximately 128,600 bbl/d, as a result the Company's curtailment optimization strategy and the ramp up of new pad tie-ins completed in Q4/19.
  - Strong annual operating costs from the Company's thermal in situ assets were achieved in 2020, averaging $9.44/bbl (US$7.04/bbl), a decrease of 13% or $1.39/bbl from 2019 levels. The decrease in operating costs was primarily due to cost savings as a result of operational synergies and higher production volumes, offset by higher fuel costs.
- North America annual natural gas production was strong in 2020 averaging 1,450 MMcf/d, comparable with 2019 levels. Strong base production, highly economic volumes additions and acquired production in the second half of the year resulted in significant exit rate volumes of 1,624 MMcf/d in December 2020.
  - North America natural gas operating costs in 2020 averaged $1.14/Mcf, a decrease of 2% from 2019 levels, demonstrating the Company's continued focus on effective and efficient operations.
- The strength of the Company's assets are shown in its ability to generate significant and sustainable free cash flow over the long term, supported by effective and efficient operations, making Canadian Natural’s business unique, robust and sustainable. As a result, 2021 adjusted funds flow is targeted to be $10.3 billion to $10.8 billion at an annual WTI level of approximately US$57/bbl, demonstrating the significant torque of the Company's assets to improving commodity prices.
  - 2021 free cash flow is targeted to be robust at $4.9 billion to $5.4 billion, after capital expenditures and increased dividend levels.
  - The Company's 2021 capital program of approximately $3.2 billion, provides a targeted production range of 1,190 MBOE/d to 1,260 MBOE/d, an increase of 5% at the mid-point from 2020 levels.
    - Corporate annual natural gas production is targeted to range between 1,620 MMcf/d to 1,680 MMcf/d in 2021, representing significant growth of over 170 MMcf/d at the mid-point, from 2020 levels.
    - Corporate annual liquids production is targeted to be strong in 2021 ranging from 920,000 bbl/d to 980,000 bbl/d, an increase of approximately 32,000 bbl/d at the mid-point, from 2020 levels.
    - Free cash flow is targeted to be allocated to the balance sheet in the near term resulting in targeted 2021 year ended debt to book capitalization and debt to adjusted EBITDA of approximately 29% and 1.2x respectively, at the mid-point of targeted free cash flow range.
    - 2020 dividends increased 13% from 2019 levels to $1.70 per share. Subsequent to year end, the Company declared a quarterly dividend increase of 11% to $0.47 per share, payable on April 5, 2021. The increase marks the 21st consecutive year of dividend increases, reflecting the Board of Directors' confidence in Canadian Natural's strength and robustness of the Company's assets and its ability to generate significant and sustainable free cash flow.
    - Subsequent to year end, in March 2021 the Board of Directors authorized management, subject to acceptance by the TSX, to repurchase shares under an NCIB, equal to options exercised throughout the coming year, in order to eliminate dilution for shareholders.

RESERVES UPDATE

- Canadian Natural's crude oil, SCO, bitumen, natural gas and NGL 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, 2020 (all reserves values are Company Gross unless stated otherwise).

- Total proved reserves increased 10% to 12.106 billion BOE with reserves additions and revisions of 1.538 billion BOE. Total proved plus probable reserves increased 12% to 15.925 billion BOE with reserves additions and revisions of 2.099 billion BOE.
  - The strength and depth of the Company's assets are evident as approximately 80% of total proved reserves are long life low decline. This results in a total proved BOE reserves life index of 29.8 years and a total proved plus probable BOE reserves life index is 39.2 years.
    - Additionally, high value, zero decline, SCO is approximately 58% of total proved reserves with a reserve life index of approximately 45 years.
- Canadian Natural’s 2020 performance has once again consistently delivered superior finding and development costs:
  - Finding, Development and Acquisition ("FD&A") costs, excluding changes in Future Development Cost ("FDC"), are $1.91/BOE for total proved reserves and $1.40/BOE for total proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $4.46/BOE for total proved reserves and $3.46/BOE for total proved plus probable reserves.
- Total proved reserves additions and revisions replaced 2020 production by 361%. Total proved plus probable reserves additions and revisions replaced 2020 production by 493%.
- Proved developed producing reserves additions and revisions are 1.032 billion BOE, replacing 2020 production by 242%. The proved developed producing BOE reserves life index is 21.2 years.
- The net present value of future net revenues, before income tax, discounted at 10%, is $80.7 billion for total proved reserves, $98.0 billion for total proved plus probable reserves and $61.4 billion for proved developed producing reserves.

QUARTERLY HIGHLIGHTS

- Net earnings of $749 million and adjusted net earnings from operations of $176 million were realized in Q4/20, improving over Q3/20 levels as expected. The increases in net earnings and adjusted net earnings are primarily a result of increased volumes from the Oil Sands Mining and Upgrading and Natural Gas segments as well as decreased operating costs from Oil Sands Mining and Upgrading.
- Cash flows from operating activities were $1,270 million in Q4/20.
- Canadian Natural generated strong quarterly adjusted funds flow of $1,851 million in Q4/20 excluding the provision relating to the Keystone XL pipeline project of $143 million. Strong adjusted funds flow was driven by the Company's effective and efficient operations and increased high value production.
- Canadian Natural generated $694 million in free cash flow in Q4/20, after net capital expenditures of $655 million and dividend payments of $502 million in the quarter, excluding Painted Pony acquisition costs and the provision, reflecting the strength of the Company's effective and efficient operations and its high quality, long life low decline asset base.
- Canadian Natural maintained a strong financial position in Q4/20 and reduced net debt by approximately $432 million, from Q3/20 levels, including Painted Pony acquisition costs.
- In Q4/20, the Company achieved record quarterly production volumes of 1,201,198 BOE/d, increases of 4% and 8% from Q4/19 and Q3/20 levels respectively. The increase in production from the comparable periods primarily reflected the completion of planned maintenance and turnaround activities combined with continued high utilization rates and operational enhancements in the Oil Sands Mining and Upgrading segment, increased natural gas activity throughout the year and closing of the Painted Pony acquisition in Q4/20.
  - Liquids production was strong in Q4/20 averaging 927,190 bbl/d, comparable to Q4/19 levels and an increase of 5% from Q3/20 levels.
  - Corporate natural gas production was 1,644 MMcf/d in Q4/20, increases of 13% and 21% from Q4/19 and Q3/20 levels respectively.
- The Company's world class Oil Sands Mining and Upgrading assets recorded strong operational results, high utilization and captured operational enhancements in Q4/20 resulting in average production of 417,089 bbl/d of SCO, increases of 17% and 19% from Q4/19 and Q3/20 levels respectively.

- Operating costs from the Company's Oil Sands Mining and Upgrading assets are industry leading, averaging $20.20/bbl (US$15.50/bbl) of SCO in Q4/20, decreases of 19% and 15% from Q4/19 and Q3/20 levels respectively, driven by the Company's continued focus on effective and efficient operations and increased production volumes.

▪ Canadian Natural's North America E&P liquids production, including thermal in situ, was strong in Q4/20 averaging 475,889 bbl/d, decreasing as expected by 6% and 4% from Q4/19 and Q3/20 levels respectively as the Company optimized production volumes within the mandatory Government of Alberta curtailment program.

  - Canadian Natural's continued focus on delivering effective and efficient operations across its entire asset base was also demonstrated at the Company's North American E&P liquids, including thermal in situ operations, where operating costs of $10.81/bbl (US$8.30/bbl) were achieved in Q4/20, comparable to Q4/19 levels.

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 Synthetic Crude Oil ("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 long life low decline production, representing approximately 80% of the Company's total liquids production in Q4/20, 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 long life low decline, low reserves replacement cost, 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 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			
	2020		2019	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**48**	**42**	96	86
Natural gas	**34**	**30**	30	19
Dry	**—**	**—**	3	3
Subtotal	**82**	**72**	129	108
Stratigraphic test / service wells	**427**	**372**	519	447
Total	**509**	**444**	648	555
Success rate (excluding stratigraphic test / service wells)		**100%**		97%

- The Company's total crude oil and natural gas drilling program of 72 net wells for the year ended December 31, 2020, excluding stratigraphic/service wells, represents a decrease of 36 net wells from 2019 levels.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs production (bbl/d)	**209,710**	206,974	247,184	**211,472**	238,028
Net wells targeting crude oil	**5**	—	9	**35**	79
Net successful wells drilled	**5**	—	9	**35**	77
Success rate	**100%**	—	100%	**100%**	97%

- Canadian Natural's North America E&P crude oil and NGL annual production volumes, excluding the Company's thermal in situ operations, averaged 211,472 bbl/d in 2020, a decrease of 11% from 2019 levels. The decrease from 2019 reflects natural declines and strategic decisions to limit capital investment.

- Primary heavy crude oil production averaged 70,279 bbl/d in 2020, a decrease of 14% from 2019 levels. The decrease in production relative to 2019 was due to natural field declines, low commodity prices and the mandatory Government of Alberta curtailment program.
    - Operating costs in the Company's primary heavy crude oil operations in 2020 averaged $17.59/bbl (US$13.11/bbl), a 6% increase from 2019 levels.
- Pelican Lake production was strong in 2020 averaging 56,535 bbl/d of long life low decline production, a decrease of only 4% from 2019 levels. The decrease from 2019 levels demonstrates Pelican Lake's low decline rate and the continued success of the Company's world class polymer flood.
    - The Company continues to focus on effective and efficient operations, realizing strong operating costs in 2020 at Pelican Lake, averaging $6.03/bbl (US$4.49/bbl), a decrease of 3% from 2019 levels.
- North American light crude oil and NGL production averaged 84,658 bbl/d in 2020, a decrease of 13% from 2019 levels primarily as a result of natural field declines.
    - Operating costs in the Company's North America light crude oil and NGL areas averaged $14.61/bbl (US$10.89/bbl) in 2020, a decrease of 4% from 2019 levels, as a result of the Company's continued focus on effective and efficient operations.
    - The Company continues to advance its high value Montney light crude oil development plan at Wembley, including 18 net wells targeted in 2021 and construction is underway on the new crude oil battery targeted to be on-stream in October 2021. With the crude oil battery in place the new wells are targeted to be brought on stream at strong capital efficiencies of approximately $9,400 per flowing BOE. This project is targeting to exit 2021 at total production rates of approximately 8,500 bbl/d of liquids and 28 MMcf/d.

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Bitumen production (bbl/d)	**266,179**	287,978	259,387	**248,971**	167,942
Net wells targeting bitumen	**—**	—	3	**6**	3
Net successful wells drilled	**—**	—	3	**6**	3
Success rate	**—**	—	100%	**100%**	100%

- Canadian Natural's thermal in situ assets achieved record annual daily production in 2020, averaging 248,971 bbl/d, an increase of 48% over 2019 levels. The record daily production levels in 2020 were primarily as a result of a full year of operatorship of Jackfish and increased production at Kirby North.
    - Record monthly production was achieved at Jackfish in October 2020 reaching approximately 128,600 bbl/d, as a result the Company's curtailment optimization strategy and the ramp up of new pad tie-ins completed in Q4/19.
    - Strong annual operating costs from the Company's thermal in situ assets were achieved in 2020, averaging $9.44/bbl (US$7.04/bbl), a decrease of 13% or $1.39/bbl from 2019 levels. The decrease in operating costs was primarily due to cost savings as a result of operational synergies and higher production volumes, offset by higher fuel costs.
    - At Jackfish, the Company achieved annual production of 103,294 bbl/d in 2020, an increase of 102% from 2019 levels. The increase was as a result of the Company's first full year of operatorship of the Jackfish assets and increased production throughout 2020 as a result of new pad tie-ins completed in Q4/19.
    - At Kirby, strong annual production of 61,476 bbl/d was achieved in 2020, an increase of 80% from 2019 levels as Kirby North averaged approximately 42,000 bbl/d in the second half of the year, continuing to produce above facility nameplate capacity.
    - At Primrose, annual production increased by 4% from 2019 levels, averaging 81,991 bbl/d in 2020 as the Company continues to optimize steam cycles.
- At Kirby South, the Company continues to see positive results from its on-going two year solvent enhanced oil recovery technology pilot. The Company is also developing a second pilot in the steam flood area at Primrose, targeted to begin in the latter half of 2021. The technology targets to increase bitumen production, with a Steam to

Oil Ratio ("SOR") reduction of up to 50%, GHG intensity reduction of up to 50% and high solvent recovery. The Company will continue to monitor results of the pilots throughout 2021 as this technology has the potential for application throughout the Company's extensive thermal in situ asset base.

North America Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Natural gas production (MMcf/d)	**1,623**	1,340	1,411	**1,450**	1,443
Net wells targeting natural gas	**9**	9	4	**30**	20
Net successful wells drilled	**9**	9	4	**30**	19
Success rate	**100%**	100%	100%	**100%**	95%

- North America annual natural gas production was strong in 2020 averaging 1,450 MMcf/d, comparable with 2019 levels. Strong base production, highly economic volumes additions and acquired production in the second half of the year resulted in significant exit rate volumes of 1,624 MMcf/d in December 2020.
  - As identified in May 2020, the Company completed its plan of adding low cost, volume adding opportunities in Q4/20. Results have been highly successful, with stronger than expected exit production rates totaling 69 MMcf/d, for less than $2,000 per flowing BOE, approximately $1,000 per flowing BOE lower than originally estimated.
- North America natural gas operating costs in 2020 averaged $1.14/Mcf, a decrease of 2% from 2019 levels, demonstrating the Company's continued focus on effective and efficient operations.
- At Septimus, in the high value liquids rich Montney, the Company drilled eight net wells which came on production in Q4/20 with strong capital efficiencies at approximately $4,800 per flowing BOE. Total current production rates from the wells is strong at approximately 46 MMcf/d and 2,150 bbl/d of NGLs, in-line with expectations.
  - Annual operating costs at Septimus remained strong in 2020, averaging $0.30/Mcfe, comparable to 2019 levels.
- Subsequent to year end, within our high quality Montney lands at Townsend, six of seven wells were brought on production at strong total rates of approximately 74 MMcf/d, compared to a target of 50 MMcf/d, resulting in a strong capital efficiency of approximately $2,200 per flowing BOE.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil production (bbl/d)					
North Sea	**17,057**	21,220	30,860	**23,142**	27,919
Offshore Africa	**17,155**	17,537	18,495	**17,022**	21,371
Natural gas production (MMcf/d)					
North Sea	**4**	5	25	**12**	24
Offshore Africa	**17**	17	19	**15**	24
Net wells targeting crude oil	**—**	—	—	**1.0**	5.5
Net successful wells drilled	**—**	—	—	**1.0**	5.5
Success rate	**—**	—	—	**100%**	100%

- International E&P annual crude oil production volumes averaged 40,164 bbl/d in 2020, a decrease of 19% from 2019 levels.

- In the North Sea, annual crude oil production volumes averaged 23,142 bbl/d in 2020, a decrease of 17% from 2019 levels. The decrease in production in 2020 was primarily a result of the permanent cessation of production from the Banff and Kyle fields and natural field declines.
  - Crude oil operating costs in the North Sea averaged $36.51/bbl (US$27.21/bbl) in 2020, comparable with 2019 levels.
- Offshore Africa annual crude oil production volumes averaged 17,022 bbl/d in 2020, a decrease of 20% from 2019 levels, primarily due to natural field declines.
  - Offshore Africa crude oil operating costs averaged $13.29/bbl (US$9.91/bbl) in 2020, an increase of 19% from 2019 levels, primarily due to lower volumes on a relatively fixed cost base.
  - Subsequent to quarter end, the Floating Production Storage and Offloading vessel ("FPSO") operator at Espoir reported a serious incident in which two of its employees were fatally injured on January 14, 2021. Operations on the FPSO were immediately suspended and production was shut-in. Late in February 2021 the operator of the FPSO safely resumed operations, and is currently reinitiating production of the field.
- As previously announced, the operator of the South Africa block 11B/12B, where Canadian Natural has a 20% working interest, has made a significant gas condensate discovery on the Luiperd prospect. This discovery follows the previously announced Brulpadda discovery in 2019. The operator is currently evaluating development scenarios following the successful discovery wells.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Synthetic crude oil production (bbl/d) (1) (2)	**417,089**	350,633	357,856	**417,351**	395,133

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

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

▪ The Company's world class Oil Sands Mining and Upgrading assets averaged annual production of 417,351 bbl/d of SCO, an increase of 6% from 2019 levels. The increase from 2019 levels was as a result of high utilization rates and operational enhancements.

- Record monthly production and high utilization was achieved at the Company's Oil Sands Mining and Upgrading assets in December 2020 of approximately 490,800 bbl/d of SCO, following the completion of planned turnarounds, increased capacity at the Scotford and elimination of the mandatory Government of Alberta curtailment program.
- Record low annual operating costs from the Company's Oil Sands Mining and Upgrading assets were achieved in 2020, averaging $20.46/bbl (US$15.25/bbl) of SCO. Operating costs decreased by 9% or $2.10/bbl from 2019 levels, driven by the Company's continued focus on effective and efficient operations, high reliability, as well as operational enhancements.
  - In 2020 the Company increased annual SCO production by approximately 22,000 bbl/d over 2019 levels and reduced annual operating costs by $183 million, excluding natural gas costs as the Company continues to focus on effective and efficient operations.

▪ As part of the 2021 budget, a planned 30 day turnaround at Horizon is scheduled for the month of April. During the shutdown, new incremental operational tankage at the upgrader is coordinated to be tied in.

▪ At Scotford no turnaround activities are targeted for 2021. The front end gross capacity was successfully increased by 20,000 bbl/d to 320,000 bbl/d as part of the Q3/20 turnaround activities.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) [(1)]	**$ 42.67**	$ 40.94	$ 56.96	**$ 39.40**	$ 57.04
WCS heavy differential as a percentage of WTI (%) [(2)]	**22%**	22%	28%	**32%**	22%
SCO price (US$/bbl)	**$ 39.69**	$ 38.61	$ 56.32	**$ 36.26**	$ 56.35
Condensate benchmark pricing (US$/bbl)	**$ 42.54**	$ 37.55	$ 52.99	**$ 36.97**	$ 52.84
Average realized pricing before risk management (C$/bbl) [(3)]	**$ 40.56**	$ 40.14	$ 49.60	**$ 31.90**	$ 55.08
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.62**	$ 2.03	$ 2.21	**$ 2.12**	$ 1.54
Average realized pricing before risk management (C$/Mcf)	**$ 2.94**	$ 2.31	$ 2.64	**$ 2.40**	$ 2.34

(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.

- Canadian Natural has a balanced and diverse product mix with strong expertise in marketing its products. Additionally, flexibility of the Company's production is targeted to be maximized in 2021, as the Government of Alberta suspended the mandatory curtailment production limits as of December 1, 2020.
- Natural gas prices improved throughout 2020, with AECO averaging $2.12/GJ in the year, an increase of 38% from 2019 levels. The increase in natural gas prices from the comparable period primarily reflects lower WCSB production levels.
- Market egress will continue to improve in the mid-term as construction is progressing on the Trans Mountain Expansion ("TMX") on which Canadian Natural has 94,000 bbl/d committed capacity. Including the Enbridge Line 3 replacement, Western Canadian egress is targeted to increase by approximately 1.0 MMbbl/d in the mid-term.
  - Enbridge Line 3 continues to progress and is targeted to be on stream in Q4/21.
  - Canadian Natural is committed to approximately 10,000 bbl/d of the targeted 50,000 bbl/d base Keystone export pipeline optimization expansion, which is targeted to be on-stream in the latter half of 2021.
  - TMX construction is on track for a targeted on stream date late in 2022.
  - On January 20, 2021, the presidential permit granted in 2019 on the Keystone XL Pipeline was revoked following the US presidential inauguration.
- The North West Redwater ("NWR") Refinery reached commercial operations on June 1, 2020 and has a targeted processing capacity of approximately 80,000 bbl/d of diluted bitumen, which will improve heavy oil demand in western Canada, effectively increasing egress out of the WCSB. For more details, please contact the North West Redwater Partnership.

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, achieved annual production of 1,164,136 BOE/d in 2020, with approximately 98% of total production located in G7 countries.

- In 2020, the Company generated annual free cash flow of $692 million after dividend requirements and capital expenditures, before Painted Pony acquisition costs, share repurchases and the provision relating to the Keystone XL pipeline project while managing through mandatory production volume curtailments, a volatile commodity price environment and lower crude oil demand, due to the global pandemic.
  - These results are a clear demonstration of the strength and resiliency of the Company's diverse, high quality, long life low decline asset base and effective and efficient operations that delivered a dividend increase in 2020 and excluding Painted Pony acquisition costs, would have decreased net debt from year ended 2019 levels.
- Canadian Natural generated strong annual adjusted funds flow of $5,343 million in 2020, excluding the provision relating to the Keystone XL pipeline project of $143 million, fully covering the Company's net capital expenditures and dividend that was increased in March 2020.
  - Canadian Natural generated $692 million in free cash flow in 2020, after dividend payments of $1,950 million and net capital expenditures of $2,701 million, excluding Painted Pony acquisition costs, share repurchases and the provision relating to the Keystone XL pipeline project.
- Canadian Natural maintained a strong financial position in 2020 and would have reduced year ended net debt by $79 million from year ended 2019 levels when excluding Painted Pony acquisition costs.
  - Including Painted Pony acquisition costs, in the second half of 2020 the Company reduced absolute net debt by over $1.5 billion from June 30, 2020 levels.
  - As at December 31, 2020, the Company had undrawn revolving bank credit facilities of approximately $5.0 billion. Including cash and cash equivalents and short-term investments, the Company had significant liquidity of approximately $5.4 billion. At December 31, 2020, the Company had approximately $0.5 billion drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - In 2020, the Company repaid $0.9 billion of 2.05% medium-term notes and $1.0 billion of 2.89% medium-term notes in Q2/20 and Q3/20, respectively.
  - In 2020, the Company successfully accessed both the Canadian and United States debt capital markets. Details are summarized as follows:
    - US dollar denominated debt securities were issued in Q2/20 totaling US$1.1 billion, including a US$0.6 billion, 5 year, 2.05% note and a US$0.5 billion,10 year, 2.95% note.
    - Canadian dollar denominated medium-term notes were issued in Q4/20 totaling $0.8 billion, including a $0.5 billion, 3 year, 1.45% note and a $0.3 billion, 7 year 2.50% note.
  - In 2020, the Company's $750 million non-revolving term credit facility, originally due February 2021 was increased by $250 million to $1,000 million and extended to February 2022. Subsequent to year end, in Q1/21, the Company has extended the facility to February 2023.
  - In Q2/20 the Company repaid $162.5 million on its $3,250 million non-revolving term loan, relating to the annual amortization requirement. Subsequent to year end, in Q1/21, the Company repaid a further $362.5 million on the facility, reducing the outstanding balance to $2,725 million, and satisfying the required annual amortization of $162.5 million originally due in June 2021.
  - The Company has approximately $4.6 billion of availability under its United States (US$1.9 billion) and Canadian (C$2.2 billion) base shelf prospectuses, which expire August 2021, allowing the Company to offer these securities for sale from time to time.
- Returns to shareholders totaled $2,221 million in 2020 by way of dividends and share repurchases.
- The strength of the Company's assets are shown in its ability to generate significant and sustainable free cash flow over the long term, supported by effective and efficient operations, making Canadian Natural’s business unique, robust and sustainable. As a result, 2021 adjusted funds flow is targeted to be $10.3 billion to $10.8 billion at an annual WTI level of approximately US$57/bbl, demonstrating the significant torque of the Company's assets to improving commodity prices.
  - 2021 free cash flow is targeted to be robust at $4.9 billion to $5.4 billion, after capital expenditures and increased dividend levels.

- The Company's 2021 capital program of approximately $3.2 billion, provides a targeted production range of 1,190 MBOE/d to 1,260 MBOE/d, an increase of 5% at the mid-point from 2020 levels.
  - Corporate annual natural gas production is targeted to range between 1,620 MMcf/d to 1,680 MMcf/d in 2021, representing significant growth of over 170 MMcf/d at the mid-point, from 2020 levels.
  - Corporate annual liquids production is targeted to be strong in 2021 ranging from 920,000 bbl/d to 980,000 bbl/d, an increase of approximately 32,000 bbl/d at the mid-point, from 2020 levels.
  - Free cash flow is targeted to be allocated to the balance sheet in the near term resulting in targeted 2021 year ended debt to book capitalization and debt to adjusted EBITDA of approximately 29% and 1.2x respectively, at the mid-point of targeted free cash flow range.
  - 2020 dividends increased 13% from 2019 levels to $1.70 per share. Subsequent to year end, the Company declared a quarterly dividend increase of 11% to $0.47 per share, payable on April 5, 2021. The increase marks the 21st consecutive year of dividend increases, reflecting the Board of Directors' confidence in Canadian Natural's strength and robustness of the Company's assets and its ability to generate significant and sustainable free cash flow.
  - Subsequent to year end, in March 2021 the Board of Directors authorized management, subject to acceptance by the TSX, to repurchase shares under an NCIB, equal to options exercised throughout the coming year, in order to eliminate dilution for shareholders.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE ("ESG") HIGHLIGHTS

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

2020 ESG HIGHLIGHTS

- Canadian Natural's corporate GHG emissions intensity continues to improve, decreasing by 18% from 2016 to 2020, a material reduction in emissions intensity. These 2020 results include a decrease of 2% from 2019 levels.
- The Company reduced methane emissions in its North American E&P segment by 28% from 2016 to 2020, which includes a decrease of 14% from 2019 levels.
- The Company continues to improve corporate total recordable injury frequency ("TRIF") in 2020, with a TRIF of 0.21 in 2020 compared to 0.50 in 2016. The Company's TRIF is down 58% since 2016, while man-hours have increased over this time period.
- Canadian Natural is one of the largest owners of Carbon Capture and Storage ("CCS") and sequestration capacity in the oil and natural gas sector globally through projects at Horizon, the Company’s 70% owned Quest CCS facility located at Scotford, and its 50% working interest in the NWR Refinery. As part of our comprehensive GHG emissions reduction strategy, our CCS projects include carbon dioxide ("CO_2") storage in geological formations, the use of CO_2 in enhanced oil recovery techniques and injection of CO_2 into tailings. Gross carbon capture capacity through these projects combined is approximately 2.7 million tonnes of CO_2 annually, equivalent to taking approximately 576,000 cars off the road per year.
  - The Quest CCS facility captures and stores approximately 1.1 million tonnes of CO_2 per year and in May 2020 reached the milestone of 5 million tonnes of stored carbon dioxide. 5 million tonnes of CO_2 is equal to the annual emissions from approximately 1.25 million cars.
  - At Horizon, annual capture capacity is approximately 0.4 million tonnes of CO_2 from the hydrogen plant, the equivalent of removing approximately 85,000 cars off the road annually.
  - At the NWR Refinery, captured CO_2 from the refinery began to be delivered in March 2020 to the Alberta Carbon Truck Line for enhanced oil recovery and permanent storage in central Alberta. At full capacity, approximately 1.2 million tonnes of CO_2 per year will be captured, the equivalent of removing approximately 256,000 cars off the road annually.
- The Company continues to increase the level of third party verified direct GHG emissions and indirect energy use.
  - The Company targets to increase the total corporate level of third party verification of GHG emissions to 95% in 2021, an increase of 9% from 2020 targeted levels.

- In 2020 the Company planted its one millionth tree at AOSP and its one and a half millionth tree at Horizon, reclaiming land and contributing to increased carbon capture.
- In 2020 the Company successfully achieved three of our four current environmental targets relating to GHG and methane emissions intensity reductions and reduced fresh water usage, and as a result we plan to update our environmental targets in Q2/21.
- In September 2020, Canadian Natural published its 2019 Stewardship Report to Stakeholders, which is available on the Company's website at https://www.cnrl.com/report-to-stakeholders. The report displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing its environmental footprint. Canadian Natural outlined its pathway to lower carbon emissions and its journey to achieve its aspirational goal of net zero GHG emissions in the oil sands.
- The Company targets the release of its 2020 Stewardship Report to Stakeholders in Q3/21.

ESG HIGHLIGHTS FROM OUR STEWARDSHIP REPORT RELEASED IN 2020

- Three of the eight independent directors of our Board are female, achieving the Company's Board gender diversity target of no less than 30% of independent directors.
- We awarded over $550 million in contracts to more than 150 Indigenous businesses during the period covered by the report.
- Canadian Natural has invested over $3.7 billion in research and development over the last decade and continues to invest in technology to unlock reserves, become more effective and efficient and reduce the Company's environmental footprint. Many of the Company’s technology projects are featured in its 2020 Technology and Innovation Case Studies on the Company’s website at www.cnrl.com/innovation-case-studies.
- Oil Sands Mining and Upgrading fresh river water use intensity decreased by 68% from 2012 to 2019.
- Thermal in situ fresh water use intensity decreased by 61% from 2012 to 2019.

2020 YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2020, 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, 2020
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	142	81	216	580	6,870	3,725	98	8,607
Developed Non-Producing	24	12	—	27	—	264	4	111
Undeveloped	149	84	49	1,876	92	5,476	225	3,388
Total Proved	315	177	265	2,483	6,962	9,465	326	12,106
Probable	148	82	130	1,674	534	6,457	174	3,819
Total Proved plus Probable	463	260	395	4,157	7,496	15,922	500	15,925

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 were provided by Sproule Associates Limited:

		2021	2022	2023	2024	2025
Crude Oil and NGL						
WTI	US$/bbl	46.00	48.00	53.00	54.06	55.14
WCS	C$/bbl	43.51	46.10	52.60	53.65	54.72
Canadian Light Sweet	C$/bbl	54.55	57.14	63.64	64.91	66.21
Cromer LSB	C$/bbl	54.55	56.64	62.64	63.89	65.17
Edmonton C5+	C$/bbl	55.84	58.40	64.82	66.11	67.44
Brent	US$/bbl	48.00	50.00	55.00	56.10	57.22
Natural gas						
AECO	C$/MMBtu	2.86	2.78	2.69	2.75	2.80
BC Westcoast Station 2	C$/MMBtu	2.76	2.68	2.59	2.64	2.69
Henry Hub	US$/MMBtu	3.00	3.00	3.00	3.06	3.12

   All prices increase at a rate of 2%/year after 2025.

   A foreign exchange rate of 0.7700 US$/C$ for 2021 and 0.7700 US$/C$ after 2021 was used in the year-end 2020 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 is based on the amount for the relevant reserves category divided by the 2021 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 2020 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 2020 and net changes in FDC from December 31, 2019 to December 31, 2020 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, 2020 and forecast estimates of ADR costs attributable to future development activity.

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Special Note Regarding non-GAAP Financial Measures

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

Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP 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 and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure as it demonstrates the Company’s ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation “Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities” is presented in the Company’s MD&A.

Net capital expenditures is a non-GAAP 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, investment in other long-term assets, share consideration in business acquisitions and abandonment expenditures. The Company considers net capital expenditures a key measure as it provides an understanding of the Company’s capital spending activities in comparison to the Company's annual capital budget. The reconciliation “Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities” is presented in the Net Capital Expenditures section of the Company’s MD&A.

Free cash flow is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital from operating activities, abandonment, certain movements in other long-term assets, less net capital expenditures and dividends on common shares. The Company considers free cash flow a key measure in demonstrating the Company’s ability to generate cash flow to fund future growth through capital investment, pay returns to shareholders, and to repay debt.

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

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

Debt to book capitalization is a non-GAAP measure that is derived as net current and long-term debt, divided by the book value of common shareholders' equity plus net current and long-term debt. The Company considers this ratio to be a key measure in evaluating the Company's ability to pay off its debt.

Available liquidity is a non-GAAP measure that is derived as cash and cash equivalents, total bank and term credit facilities, less amounts drawn on the bank and credit facilities including under the commercial paper program. The Company considers available liquidity a key measure in evaluating the sustainability of the Company’s operations and ability to fund future growth. See note 9 - Long-term Debt in the Company’s consolidated financial statements.

The Company's 2021 targeted annual adjusted funds flow and free cash flow are based upon forecasted commodity prices of US$57.28 WTI/bbl, WCS discount of US$11.77/bbl, AECO price of C$2.88/GJ and FX of US$1.00 to C$1.27.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

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Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses and other targets provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to the Company's assets at Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), Primrose thermal oil projects, the Pelican Lake water and polymer flood projects, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project, the North West Redwater bitumen upgrader and refinery, construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs") or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market, the development and deployment of technology and technological innovations, and the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long term also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of effects of the novel coronavirus ("COVID-19") pandemic and the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+") which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil and natural gas and NGLs prices including due to actions of OPEC+ taken in response to COVID-19 or otherwise; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities (including production curtailments mandated by the Government of Alberta); government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short, medium, and long term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; the continued availability of the Canada Emergency Wage Subsidy ("CEWS") or other subsidies; and other circumstances affecting revenues and expenses.

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

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

Special Note Regarding non-GAAP Financial Measures

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

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three months and year ended December 31, 2020 and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2019. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s unaudited interim consolidated financial statements for the three months and year ended December 31, 2020 and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

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

The following discussion and analysis refers primarily to the Company’s financial results for the three months and year ended December 31, 2020 in relation to the comparable periods in 2019 and the third quarter of 2020. 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, 2019, 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 3, 2021.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Dec 31 2020	Sep 30 2020	Dec 31 2019	Year Ended Dec 31 2020	Dec 31 2019
Product sales (1)	**$ 5,219**	$ 4,676	$ 6,335	**$ 17,491**	$ 24,394
Crude oil and NGLs	**$ 4,592**	$ 4,202	$ 5,947	**$ 15,579**	$ 22,950
Natural gas	**$ 496**	$ 338	$ 382	**$ 1,478**	$ 1,419
Net earnings (loss)	**$ 749**	$ 408	$ 597	**$ (435)**	$ 5,416
Per common share – basic	**$ 0.63**	$ 0.35	$ 0.50	**$ (0.37)**	$ 4.55
– diluted	**$ 0.63**	$ 0.35	$ 0.50	**$ (0.37)**	$ 4.54
Adjusted net earnings (loss) from operations (2)	**$ 176**	$ 135	$ 686	**$ (756)**	$ 3,795
Per common share – basic	**$ 0.15**	$ 0.11	$ 0.58	**$ (0.64)**	$ 3.19
– diluted	**$ 0.15**	$ 0.11	$ 0.58	**$ (0.64)**	$ 3.18
Cash flows from operating activities	**$ 1,270**	$ 2,070	$ 2,454	**$ 4,714**	$ 8,829
Adjusted funds flow (3)	**$ 1,708**	$ 1,740	$ 2,494	**$ 5,200**	$ 10,267
Per common share – basic	**$ 1.45**	$ 1.47	$ 2.11	**$ 4.40**	$ 8.62
– diluted	**$ 1.44**	$ 1.47	$ 2.10	**$ 4.40**	$ 8.61
Cash flows used in investing activities	**$ 624**	$ 643	$ 854	**$ 2,819**	$ 7,255
Net capital expenditures (4)	**$ 1,176**	$ 771	$ 1,056	**$ 3,206**	$ 7,121

(1) Further details related to product sales are disclosed in note 18 to the Company's unaudited interim consolidated financial statements.

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

(3) Adjusted funds flow is a non-GAAP financial measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to North West Redwater Partnership ("NWRP") and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure in evaluating its performance as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" is presented in this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.

(4) Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, the repayment of NWRP subordinated debt advances, abandonment expenditures, and other. The Company considers net capital expenditures a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the "Net Capital Expenditures" section of this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.

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

($ millions)	Three Months Ended **Dec 31 2020**	Three Months Ended Sep 30 2020	Three Months Ended Dec 31 2019	Year Ended **Dec 31 2020**	Year Ended Dec 31 2019
Net earnings (loss)	***$ 749***	*$ 408*	*$ 597*	***$ (435)***	*$ 5,416*
Share-based compensation, net of tax (1)	***117***	*(5)*	*148*	***(86)***	*210*
Unrealized risk management (gain) loss, net of tax (2)	***(16)***	*(1)*	*16*	***(31)***	*14*
Unrealized foreign exchange gain, net of tax (3)	***(534)***	*(270)*	*(225)*	***(116)***	*(548)*
Realized foreign exchange gain on settlement of cross currency swaps, net of tax (4)	**—**	—	—	***(166)***	—
Gain on acquisition, net of tax (5)	***(217)***	—	—	***(217)***	—
(Gain) loss from investments, net of tax (6) (7)	***(33)***	*3*	*150*	***185***	*321*
Provision for pipeline project, net of tax (8)	***110***	—	—	***110***	—
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (9)	**—**	—	—	**—**	*(1,618)*
Adjusted net earnings (loss) from operations	***$ 176***	*$ 135*	*$ 686*	***$ (756)***	*$ 3,795*

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plan. The Company's Stock Option Plan provides for a cash payment option. 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. Accordingly, the fair value of the outstanding vested options is recognized as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings (loss) or are charged to (recovered from) the Oil Sands Mining and Upgrading segment.

(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 crude oil, natural gas and foreign exchange.

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

(4) During the 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.

(5) 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 Energy Ltd. ("Painted Pony").

(6) The Company's investment in the 50% owned NWRP is accounted for using the equity method of accounting. Included in the non-cash loss from investments is the Company's pro rata share of NWRP's equity loss recognized for the period.

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

(8) During the fourth quarter of 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.

(9) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to the underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recognized in net earnings (loss) during the period the legislation is substantively enacted. In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of this corporate income tax rate reduction, the Company's deferred corporate income tax liability decreased by $1,618 million for the year ended December 31, 2019. In the fourth quarter of 2020, the Government of Alberta substantively enacted legislation to accelerate this reduction, lowering the corporate tax rate from 10% to 8%, effective July 1, 2020. This acceleration did not have a significant impact on the Company's deferred corporate income tax liability for the year ended December 31, 2020.

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

($ millions)	Three Months Ended **Dec 31 2020**	Three Months Ended Sep 30 2020	Three Months Ended Dec 31 2019	Year Ended **Dec 31 2020**	Year Ended Dec 31 2019
Cash flows from operating activities	***$ 1,270***	*$ 2,070*	*$ 2,454*	***$ 4,714***	*$ 8,829*
Net change in non-cash working capital	***394***	*(372)*	*(52)*	***166***	*1,033*
Abandonment expenditures (1)	***52***	*68*	*84*	***249***	*296*
Other (2)	***(8)***	*(26)*	*8*	***71***	*109*
Adjusted funds flow	***$ 1,708***	*$ 1,740*	*$ 2,494*	***$ 5,200***	*$ 10,267*

(1) The Company includes abandonment expenditures in "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" in the "Net Capital Expenditures" section of this MD&A.

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

SUMMARY OF FINANCIAL HIGHLIGHTS

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

The net loss for the year ended December 31, 2020 was $435 million compared with net earnings of $5,416 million for the year ended December 31, 2019. The net loss for the year ended December 31, 2020 included net after-tax income of $321 million compared with net after-tax income of $1,621 million for the year ended December 31, 2019 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the foreign exchange gain on the settlement of the cross currency swaps, the gain on acquisition, the loss from investments, a provision relating to the Keystone XL pipeline project, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, the adjusted net loss from operations for the year ended December 31, 2020 was $756 million compared with adjusted net earnings from operations of $3,795 million for the year ended December 31, 2019.

Net earnings for the fourth quarter of 2020 were $749 million compared with net earnings of $597 million for the fourth quarter of 2019 and net earnings of $408 million for the third quarter of 2020. Net earnings for the fourth quarter of 2020 included net after-tax income of $573 million compared with net after-tax expenses of $89 million for the fourth quarter of 2019 and net after-tax income of $273 million for the third quarter of 2020 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the gain on acquisition, the (gain) loss from investments, and a provision relating to the Keystone XL pipeline project. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2020 were $176 million compared with adjusted net earnings from operations of $686 million for the fourth quarter of 2019 and adjusted net earnings from operations of $135 million for the third quarter of 2020.

The net loss and the adjusted net loss from operations for the year ended December 31, 2020 compared with net earnings and adjusted net earnings from operations for the year ended December 31, 2019 primarily reflected:

- lower crude oil and NGLs netbacks in the Exploration and Production segments;
- lower realized SCO prices in the Oil Sands Mining and Upgrading segment; and
- higher depletion, depreciation and amortization;

partially offset by:

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

Net earnings and adjusted net earnings from operations for the fourth quarter of 2020 compared with net earnings and adjusted net earnings from operations for the fourth quarter of 2019 primarily reflected:

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

partially offset by:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower SCO production costs in the Oil Sands Mining and Upgrading segment;
- higher natural gas sales volumes in the Exploration and Production segments; and
- higher natural gas netbacks in the Exploration and Production segments.

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

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower SCO production costs per bbl in the Oil Sands Mining and Upgrading segment;
- higher natural gas sales volumes in the Exploration and Production segments; and
- higher natural gas netbacks in the Exploration and Production segments;

partially offset by:

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

The impacts of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the gain on acquisition, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities 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, 2020 were $4,714 million compared with $8,829 million for the year ended December 31, 2019. Cash flows from operating activities for the fourth quarter of 2020 were $1,270 million compared with $2,454 million for the fourth quarter of 2019 and $2,070 million for the third quarter of 2020. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted relating to the fluctuations in net earnings (loss) and adjusted net earnings (loss) from operations (excluding the effects of depletion, depreciation and amortization, the gain on acquisition and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the year ended December 31, 2020 was $5,200 million compared with $10,267 million for the year ended December 31, 2019. Adjusted funds flow for the fourth quarter of 2020 was $1,708 million compared with $2,494 million for the fourth quarter of 2019 and $1,740 million for the third quarter of 2020. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures 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

Total production of crude oil and NGLs before royalties for the fourth quarter of 2020 averaged 927,190 bbl/d, comparable with 913,782 bbl/d for the fourth quarter of 2019 and an increase of 5% from 884,342 bbl/d for the third quarter of 2020. Total natural gas production before royalties for the fourth quarter of 2020 increased 13% to 1,644 MMcf/d from 1,455 MMcf/d for the fourth quarter of 2019 and increased 21% from 1,362 MMcf/d for the third quarter of 2020. Total production before royalties for the fourth quarter of 2020 increased 4% to 1,201,198 BOE/d from 1,156,276 BOE/d for the fourth quarter of 2019 and increased 8% from 1,111,286 BOE/d for the third quarter of 2020. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

Product Prices

The Company's realized pricing reflects prevailing benchmark pricing. In the Company's Exploration and Production segments, the fourth quarter of 2020 crude oil and NGLs sales price averaged $40.56 per bbl, a decrease of 18% compared with $49.60 per bbl for the fourth quarter of 2019, and comparable with $40.14 per bbl for the third quarter of 2020. The natural gas price increased 11% to average $2.94 per Mcf for the fourth quarter of 2020 from $2.64 per Mcf for the fourth quarter of 2019, and increased 27% from $2.31 per Mcf for the third quarter of 2020. In the Oil Sands Mining and Upgrading segment, the Company's SCO sales price decreased 29% to average $48.56 per bbl for the fourth quarter of 2020 from $68.67 per bbl from the fourth quarter of 2019, and was comparable with $48.92 per bbl for the third quarter of 2020. Crude oil and NGLs and natural gas prices are discussed in detail in the "Business Environment", "Product Prices – Exploration and Production", and the "Oil Sands Mining and Upgrading" sections of this MD&A.

Production Expense

In the Company's Exploration and Production segments, fourth quarter of 2020 crude oil and NGLs production expense averaged $12.47 per bbl, comparable with $12.46 for the fourth quarter of 2019, and an increase of 13% from $11.03 per bbl for the third quarter of 2020. Natural gas production expense averaged $1.10 per Mcf for the fourth quarter of 2020, a decrease of 6% from $1.17 per Mcf for the fourth quarter of 2019 and a decrease of 7% from $1.18 per Mcf for the third quarter of 2020. In the Oil Sands Mining and Upgrading segment, production costs averaged $20.20 per bbl for the fourth quarter of 2020, a decrease of 19% from $25.09 per bbl for the fourth quarter of 2019, and a decrease of 15% from $23.81 per bbl for the third quarter of 2020. 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 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)

($ millions, except per common share amounts)	Dec 31 2019	Sep 30 2019	Jun 30 2019	Mar 31 2019
Product sales [1]	$ 6,335	$ 6,587	$ 5,931	$ 5,541
Crude oil and NGLs	$ 5,947	$ 6,324	$ 5,597	$ 5,082
Natural gas	$ 382	$ 257	$ 324	$ 456
Net earnings (loss)	$ 597	$ 1,027	$ 2,831	$ 961
Net earnings (loss) per common share				
– basic	$ 0.50	$ 0.87	$ 2.37	$ 0.80
– diluted	$ 0.50	$ 0.87	$ 2.36	$ 0.80

(1) Further details related to product sales for the three months ended December 31, 2020 and 2019 are disclosed in note 18 to the Company's unaudited interim consolidated financial statements.

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

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from OPEC+ and its impact on world supply; the impact of geopolitical and market uncertainties, including those due to COVID-19 and in connection with governmental responses to COVID-19, on worldwide benchmark pricing; the impact of shale oil production in North America; the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin"); 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 due to the cyclic nature of the Company's Primrose thermal oil projects, production from the Kirby Thermal Oil Sands Project, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America and the International segments, the impact and timing of acquisitions, including the acquisition of assets from Devon Canada Corporation ("Devon") in the second quarter of 2019, as well as 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 higher return crude oil projects, natural decline rates, shut-in production due to low commodity prices and the impact and timing of acquisitions, including the acquisition of Painted Pony in the fourth quarter of 2020.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production volumes, the impact of seasonal costs, 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 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 acquisition and gains/losses on investments** – Fluctuations due to the recognition of a gain on the acquisition of Painted Pony in the fourth quarter of 2020, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss on the Company's interest in NWRP.
- **Income tax expense** – Fluctuations due to statutory tax rate and other legislative changes substantively enacted in the various periods.

BUSINESS ENVIRONMENT

Global benchmark crude oil prices decreased significantly in the first half of 2020 due to the erosion of global demand, reflecting the severity of COVID-19 and related economic conditions. In April 2020, in response to the collapse of crude oil prices, OPEC+ agreed to cut production. As the global economy improved in the latter part of the year, OPEC+ agreed to continue with production cuts implemented in the second quarter of 2020. Pricing improved in the fourth quarter of 2020 with WTI benchmark pricing averaging US$42.67 per bbl and the WCS Heavy Differential averaging US$9.30 per bbl. Subsequent to December 31, 2020, Saudi Arabia committed to reduce its production by 1.0 MMbbl/d, which had a further positive impact on crude oil pricing.

Production Flexibility and Cost Control

The Company continues to be nimble and act decisively to make appropriate operational improvements to increase efficiencies and cost control and mitigate the impact of the decline in commodity pricing across all of its operations. To mitigate the impact of realized pricing on certain crude oil products, the Company optimizes the production profile across its diverse asset base. The Company implemented changes to its compensation program in light of current commodity volatility, and these changes had an immediate impact on the Company's costs, effective April 2020. The Company is also working diligently to reduce production costs wherever possible, asking all stakeholders to contribute to the sustainability of operations.

The Company continued to prioritize the optimization of higher value light crude oil, NGLs and SCO, representing approximately 45% of total corporate BOE production volumes for the fourth quarter of 2020. Optimization of production volumes continues to be a key focus of the Company at current commodity price levels.

Production costs throughout 2020 also reflected the impact of measures to promote social distancing and other precautionary measures related to COVID-19 at the Company's head office and field locations, both internationally and in North America. The Company continues to mitigate the impact of these costs through its focus on cost control and efficiencies across the asset base.

Canada Emergency Wage Subsidy

On March 27, 2020, in response to COVID-19, the Government of Canada announced the CEWS. The CEWS enables eligible Canadian employers who have been impacted by COVID-19 to apply for a subsidy of a specified amount of eligible employee wages. The Company continued to be eligible for the subsidy in the fourth quarter of 2020 as its qualifying revenues declined by the specified amount as compared with the prior year reference period.

Liquidity

As at December 31, 2020, the Company had undrawn revolving bank credit facilities of $4,958 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,447 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit.

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

Capital Spending

Safe, reliable, effective and efficient operations continues to be a focus for the Company. On December 9, 2020, the Company announced its 2021 capital budget targeted at approximately $3,205 million, of which $1,345 million is related to conventional and unconventional assets and $1,860 million is allocated to long-life low decline assets. Production for 2021 is targeted between 1,190,000 BOE/d and 1,260,000 BOE/d. Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns and the balancing of project risks and time horizons. The 2021 capital budget and production targets constitute forward-looking information. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Risks and Uncertainties

COVID-19 continues to have the potential to further disrupt the Company’s operations, projects and financial condition through the disruption of the local or global supply chain and transportation services, or the loss of manpower resulting from quarantines that affect the Company’s labour pools in their local communities, workforce camps or operating sites or that are instituted by local health authorities as a precautionary measure, any of which may require the Company to temporarily reduce or shutdown its operations depending on their extent and severity.

Benchmark Commodity Prices

(Average for the period)	Three Months Ended Dec 31 2020	Sep 30 2020	Dec 31 2019	Year Ended Dec 31 2020	Dec 31 2019
WTI benchmark price (US$/bbl)	**$ 42.67**	$ 40.94	$ 56.96	**$ 39.40**	$ 57.04
Dated Brent benchmark price (US$/bbl)	**$ 44.52**	$ 42.74	$ 62.64	**$ 42.27**	$ 64.04
WCS Heavy Differential from WTI (US$/bbl)	**$ 9.30**	$ 9.06	$ 15.84	**$ 12.57**	$ 12.79
SCO price (US$/bbl)	**$ 39.69**	$ 38.61	$ 56.32	**$ 36.26**	$ 56.35
Condensate benchmark price (US$/bbl)	**$ 42.54**	$ 37.55	$ 52.99	**$ 36.97**	$ 52.84
Condensate Differential from WTI (US$/bbl)	**$ 0.13**	$ 3.39	$ 3.97	**$ 2.43**	$ 4.20
NYMEX benchmark price (US$/MMBtu)	**$ 2.66**	$ 1.97	$ 2.50	**$ 2.08**	$ 2.63
AECO benchmark price (C$/GJ)	**$ 2.62**	$ 2.03	$ 2.21	**$ 2.12**	$ 1.54
US/Canadian dollar average exchange rate (US$)	**$ 0.7674**	$ 0.7507	$ 0.7576	**$ 0.7454**	$ 0.7536

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

On January 1, 2019, the Government of Alberta implemented a mandatory curtailment program that has been successful in mitigating the discount in crude oil pricing received in Alberta for both light crude oil and heavy crude oil. The Government of Alberta extended the mandatory curtailment program to December 31, 2021; however, curtailment production limits were suspended effective December 1, 2020 and curtailment orders will only be issued in 2021 if deemed necessary by the Government of Alberta.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$39.40 per bbl for the year ended December 31, 2020, a decrease of 31% from US$57.04 per bbl for the year ended December 31, 2019. WTI averaged US$42.67 per bbl for the fourth quarter of 2020, a decrease of 25% from US$56.96 per bbl for the fourth quarter of 2019, and an increase of 4% from US$40.94 per bbl for the third quarter of 2020.

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$42.27 per bbl for the year ended December 31, 2020, a decrease of 34% from US$64.04 per bbl for the year ended December 31, 2019. Brent averaged US$44.52 per bbl for the fourth quarter of 2020, a decrease of 29% from US$62.64 per bbl for the fourth quarter of 2019, and an increase of 4% from US$42.74 per bbl for the third quarter of 2020.

The decrease in WTI and Brent pricing for the three months and year ended December 31, 2020 from the comparable periods in 2019 primarily reflected significant reductions in refinery utilization due to decreased demand for refined products as a result of COVID-19, resulting in an oversupply of crude oil in the market. The increase in WTI and Brent pricing for the fourth quarter of 2020 from the third quarter of 2020 primarily reflected a partial recovery in global demand and agreements by OPEC+ in the fourth quarter of 2020 to continue with production cuts implemented in the second quarter of 2020.

The WCS Heavy Differential averaged US$12.57 per bbl for the year ended December 31, 2020, comparable with US$12.79 per bbl for the year ended December 31, 2019. The WCS Heavy Differential averaged US$9.30 per bbl for the fourth quarter of 2020, a decrease of 41% from US$15.84 per bbl for the fourth quarter of 2019, and an increase of 3% from US$9.06 per bbl for the third quarter of 2020. The narrowing of the WCS Heavy Differential for the fourth quarter of 2020 from the fourth quarter of 2019 primarily reflected the impact of a significant reduction in supply from the Basin due to planned and unplanned outages, together with the partial recovery in global demand. The slight widening of the WCS Heavy Differential for the fourth quarter of 2020 from the third quarter of 2020 was primarily due to lower seasonal demand in addition to the suspension of mandatory Government of Alberta curtailment, effective

December 1, 2020. The WCS Heavy Differential in the current and the comparable periods reflected the impact of the mandatory curtailment program.

The SCO price averaged US$36.26 per bbl for the year ended December 31, 2020, a decrease of 36% from US$56.35 per bbl for the year ended December 31, 2019. The SCO price averaged US$39.69 per bbl for the fourth quarter of 2020, a decrease of 30% from US$56.32 per bbl for the fourth quarter of 2019, and an increase of 3% from US$38.61 per bbl for the third quarter of 2020. The decrease in SCO pricing for the three months and year ended December 31, 2020 from the comparable periods in 2019 primarily reflected decreases in WTI benchmark pricing. The increase in SCO pricing for the fourth quarter of 2020 from the third quarter of 2020 primarily reflected increases in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.08 per MMBtu for the year ended December 31, 2020, a decrease of 21% from US$2.63 per MMBtu for the year ended December 31, 2019. NYMEX natural gas prices averaged US$2.66 per MMBtu for the fourth quarter of 2020, an increase of 6% from US$2.50 per MMBtu for the fourth quarter of 2019, and an increase of 35% from US$1.97 per MMBtu for the third quarter of 2020. The decrease in NYMEX natural gas prices for the year ended December 31, 2020 from 2019 primarily reflected supply exceeding North American demand due to the impact of COVID-19, and lower Liquefied Natural Gas ("LNG") exports. The increase in NYMEX natural gas prices for the fourth quarter of 2020 from the comparable periods primarily reflected increased domestic demand and LNG exports, together with lower production levels.

AECO natural gas prices averaged $2.12 per GJ for the year ended December 31, 2020, an increase of 38% from $1.54 per GJ for the year ended December 31, 2019. AECO natural gas prices averaged $2.62 per GJ for the fourth quarter of 2020, an increase of 19% from $2.21 per GJ for the fourth quarter of 2019, and an increase of 29% from $2.03 per GJ for the third quarter of 2020. The increase in AECO natural gas prices for the three months and year ended December 31, 2020 from the comparable periods primarily reflected lower production levels from the Basin.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**475,889**	494,952	506,571	**460,443**	405,970
North America – Oil Sands Mining and Upgrading (1)	**417,089**	350,633	357,856	**417,351**	395,133
North Sea	**17,057**	21,220	30,860	**23,142**	27,919
Offshore Africa	**17,155**	17,537	18,495	**17,022**	21,371
	927,190	884,342	913,782	**917,958**	850,393
Natural gas (MMcf/d)					
North America	**1,623**	1,340	1,411	**1,450**	1,443
North Sea	**4**	5	25	**12**	24
Offshore Africa	**17**	17	19	**15**	24
	1,644	1,362	1,455	**1,477**	1,491
Total barrels of oil equivalent (BOE/d)	**1,201,198**	1,111,286	1,156,276	**1,164,136**	1,098,957
Product mix					
Light and medium crude oil and NGLs	**10%**	11%	12%	**11%**	13%
Pelican Lake heavy crude oil	**5%**	5%	5%	**5%**	5%
Primary heavy crude oil	**5%**	6%	8%	**6%**	8%
Bitumen (thermal oil)	**22%**	26%	23%	**21%**	15%
Synthetic crude oil (1)	**35%**	32%	31%	**36%**	36%
Natural gas	**23%**	20%	21%	**21%**	23%
Percentage of gross revenue (1) (2) (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**90%**	93%	94%	**91%**	94%
Natural gas	**10%**	7%	6%	**9%**	6%

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

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**433,697**	455,393	438,894	**420,906**	356,794
North America – Oil Sands Mining and Upgrading	**411,640**	347,475	340,262	**413,363**	375,048
North Sea	**17,023**	21,150	30,815	**23,086**	27,866
Offshore Africa	**16,416**	16,767	17,294	**16,306**	20,078
	878,776	840,785	827,265	**873,661**	779,786
Natural gas (MMcf/d)					
North America	**1,553**	1,298	1,351	**1,406**	1,400
North Sea	**4**	5	25	**12**	24
Offshore Africa	**16**	16	18	**14**	22
	1,573	1,319	1,394	**1,432**	1,446
Total barrels of oil equivalent (BOE/d)	**1,141,022**	1,060,629	1,059,562	**1,112,364**	1,020,749

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

Crude oil and NGLs production before royalties for the year ended December 31, 2020 averaged 917,958 bbl/d, an increase of 8% from 850,393 bbl/d for the year ended December 31, 2019. Crude oil and NGLs production for the fourth quarter of 2020 of 927,190 bbl/d was comparable with 913,782 bbl/d for the fourth quarter of 2019, and increased 5% from 884,342 bbl/d for the third quarter of 2020. The increase in crude oil and NGLs production for the year ended December 31, 2020 from 2019 primarily reflected the acquisition of Jackfish assets, increased thermal oil production at Kirby North, and high utilization rates and operational enhancements in the Oil Sands Mining and Upgrading segment. The increase in crude oil and NGLs production for the fourth quarter of 2020 from the comparable periods primarily reflected the completion of planned maintenance and turnaround activities at AOSP and Horizon, combined with continued high utilization rates and operational enhancements in the Oil Sands Mining and Upgrading segment. Production for all periods reflected the impact of the Company's curtailment optimization strategy as a result of mandatory Government of Alberta curtailment, which was suspended effective December 1, 2020.

Natural gas production before royalties for the year ended December 31, 2020 of 1,477 MMcf/d was comparable with 1,491 MMcf/d for the year ended December 31, 2019. Natural gas production for the fourth quarter of 2020 of 1,644 MMcf/d increased 13% from 1,455 MMcf/d for the fourth quarter of 2019, and increased 21% from 1,362 MMcf/d for the third quarter of 2020. The increase in natural gas production for the fourth quarter of 2020 from the comparable periods primarily reflected added volumes from opportunities identified by the Company in the first half of 2020 and production volumes from the acquisition of Painted Pony on October 6, 2020, partially offset by natural field declines.

Due to the uncertainty regarding COVID-19, the Company withdrew its 2020 corporate production guidance, however, annual 2020 crude oil and NGLs and natural gas production before royalties was within the previously issued corporate guidance range. Annual crude oil and NGLs production for 2021 is targeted to average between 920,000 bbl/d and 980,000 bbl/d. Annual natural gas production for 2021 is targeted to average between 1,620 MMcf/d and 1,680 MMcf/d. Production targets constitute forward-looking information. 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, 2020 averaged 460,443 bbl/d, an increase of 13% from 405,970 bbl/d for the year ended December 31, 2019. North America crude oil and NGLs production for the fourth quarter of 2020 of 475,889 bbl/d decreased 6% from 506,571 bbl/d for the fourth quarter of 2019, and decreased 4% from 494,952 bbl/d for the third quarter of 2020. The increase in crude oil and NGLs production for the year ended December 31, 2020 from 2019 primarily reflected the acquisition of Jackfish assets, increased thermal oil production at Kirby North, and the optimization of steam cycles at Primrose. The decrease in crude oil and NGLs production for the fourth quarter of 2020 from the comparable periods primarily reflected the Company's curtailment optimization strategy, including higher production in the North America – Exploration and Production segment in the fourth quarter of 2019 as the Company completed planned and unplanned maintenance in the Oil Sands Mining and Upgrading segment. Production for all periods reflected the impact of mandatory Government of Alberta curtailment, which was suspended effective December 1, 2020.

Thermal oil production before royalties for the fourth quarter of 2020 averaged 266,179 bbl/d, an increase of 3% from 259,387 bbl/d for the fourth quarter of 2019, and a decrease of 8% from 287,978 bbl/d for the third quarter of 2020. The increase in thermal oil production from the fourth quarter of 2019 primarily reflected the impact of increased production at Kirby North and Jackfish. Thermal oil production decreased from the third quarter of 2020 primarily as a result of the Company's curtailment optimization strategy.

Pelican Lake heavy crude oil production before royalties averaged 56,036 bbl/d for the fourth quarter of 2020, a decrease of 5% from 59,013 bbl/d for the fourth quarter of 2019, and was comparable with 56,392 bbl/d for the third quarter of 2020, demonstrating Pelican Lake's long-life low decline production.

Natural gas production before royalties for the year ended December 31, 2020 of 1,450 MMcf/d increased slightly from 1,443 MMcf/d for the year ended December 31, 2019. Natural gas production for the fourth quarter of 2020 averaged 1,623 MMcf/d, an increase of 15% from 1,411 MMcf/d for the fourth quarter of 2019, and an increase of 21% from 1,340 MMcf/d for the third quarter of 2020. The increase in natural gas production for the three months and year ended December 31, 2020 from the comparable periods primarily reflected added volumes from opportunities identified by the Company in the first half of 2020 and the acquisition of Painted Pony on October 6, 2020, partially offset by the impact of natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the year ended December 31, 2020 of 417,351 bbl/d increased 6% from 395,133 bbl/d for the year ended December 31, 2019. SCO production for the fourth quarter of 2020 increased 17% to average 417,089 bbl/d from 357,856 bbl/d for the fourth quarter of 2019 and increased 19% from 350,633 bbl/d for the third quarter of 2020. The increase in SCO production for the year ended December 31, 2020 from 2019 primarily reflected high utilization rates and operational enhancements, partially offset by the impact of planned maintenance activities. The increase in SCO production for the fourth quarter of 2020 from the comparable periods primarily reflected continued high utilization rates following the successful completion of planned maintenance activities at Horizon, together with expanded front-end capacity at AOSP. The fourth quarter of 2020 also reflected the impact of the Company's curtailment optimization strategy, including the suspension of mandatory Government of Alberta curtailment effective December 1, 2020.

North Sea

North Sea crude oil production before royalties for the year ended December 31, 2020 of 23,142 bbl/d decreased 17% from 27,919 bbl/d for the year ended December 31, 2019. North Sea crude oil production for the fourth quarter of 2020 decreased 45% to 17,057 bbl/d from 30,860 bbl/d for the fourth quarter of 2019 and decreased 20% from 21,220 bbl/d for the third quarter of 2020. The decrease in production for the year ended December 31, 2020 from 2019 primarily reflected the permanent cessation of production at the Banff and Kyle fields on June 1, 2020 and natural field declines. The decrease in production for the fourth quarter of 2020 from the fourth quarter of 2019 primarily reflected the permanent cessation of production at the Banff and Kyle fields on June 1, 2020, planned turnaround activities, and natural field declines. The decrease in production from the third quarter of 2020 primarily reflected planned turnaround activities during the fourth quarter of 2020 and natural field declines.

Offshore Africa

Offshore Africa crude oil production before royalties for the year ended December 31, 2020 decreased 20% to 17,022 bbl/d from 21,371 bbl/d for the year ended December 31, 2019. Offshore Africa crude oil production for the fourth quarter of 2020 of 17,155 bbl/d decreased 7% from 18,495 bbl/d for the fourth quarter of 2019 and was comparable with 17,537 bbl/d for the third quarter of 2020. The decrease in production for the three months and year ended December 31, 2020 from the comparable periods in 2019 primarily reflected natural field declines.

International Crude Oil Inventory Volumes

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

(bbl)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019
North Sea	**450,889**	730,801	344,726
Offshore Africa	**521,244**	779,347	519,504
	972,133	1,510,148	864,230

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs ($/bbl) [(1)]					
Sales price [(2)]	**$ 40.56**	$ 40.14	$ 49.60	**$ 31.90**	$ 55.08
Transportation [(3)]	**3.81**	3.60	3.53	**3.85**	3.48
Realized sales price, net of transportation	**36.75**	36.54	46.07	**28.05**	51.60
Royalties	**3.34**	3.03	6.03	**2.59**	6.08
Production expense	**12.47**	11.03	12.46	**12.42**	13.81
Netback	**$ 20.94**	$ 22.48	$ 27.58	**$ 13.04**	$ 31.71
Natural gas ($/Mcf) [(1)]					
Sales price	**$ 2.94**	$ 2.31	$ 2.64	**$ 2.40**	$ 2.34
Transportation	**0.42**	0.42	0.43	**0.43**	0.42
Realized sales price, net of transportation	**2.52**	1.89	2.21	**1.97**	1.92
Royalties	**0.13**	0.07	0.11	**0.08**	0.08
Production expense	**1.10**	1.18	1.17	**1.18**	1.22
Netback	**$ 1.29**	$ 0.64	$ 0.93	**$ 0.71**	$ 0.62
Barrels of oil equivalent ($/BOE) [(1)]					
Sales price [(2)]	**$ 32.61**	$ 32.28	$ 39.20	**$ 26.15**	$ 40.50
Transportation [(3)]	**3.37**	3.28	3.24	**3.44**	3.14
Realized sales price, net of transportation	**29.24**	29.00	35.96	**22.71**	37.36
Royalties	**2.44**	2.25	4.37	**1.89**	4.09
Production expense	**10.43**	9.84	10.79	**10.67**	11.49
Netback	**$ 16.37**	$ 16.91	$ 20.80	**$ 10.15**	$ 21.78

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

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 39.54**	$ 38.86	$ 46.06	**$ 30.31**	$ 51.43
North Sea	**$ 56.18**	$ 57.84	$ 87.76	**$ 50.09**	$ 86.76
Offshore Africa	**$ 49.05**	$ 55.11	$ 70.73	**$ 50.95**	$ 83.68
Average	**$ 40.56**	$ 40.14	$ 49.60	**$ 31.90**	$ 55.08
Natural gas ($/Mcf) (1)					
North America	**$ 2.91**	$ 2.25	$ 2.52	**$ 2.34**	$ 2.18
North Sea	**$ 1.41**	$ 3.44	$ 5.10	**$ 2.74**	$ 6.52
Offshore Africa	**$ 6.64**	$ 7.32	$ 8.58	**$ 7.77**	$ 7.41
Average	**$ 2.94**	$ 2.31	$ 2.64	**$ 2.40**	$ 2.34
Average ($/BOE) (1) (2)	**$ 32.61**	$ 32.28	$ 39.20	**$ 26.15**	$ 40.50

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

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

North America

North America realized crude oil prices decreased 41% to average $30.31 per bbl for the year ended December 31, 2020 from $51.43 per bbl for the year ended December 31, 2019. North America realized crude oil prices averaged $39.54 per bbl for the fourth quarter of 2020, a decrease of 14% compared with $46.06 per bbl for the fourth quarter of 2019, and comparable with $38.86 per bbl for the third quarter of 2020. The decrease in realized crude oil prices for the three months and year ended December 31, 2020 from the comparable periods in 2019 was primarily due to lower WTI benchmark pricing due to decreased demand for refined products as a result of COVID-19, partially offset by the narrowing of the WCS Heavy Differential. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2020 contributed approximately 138,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 7% to average $2.34 per Mcf for the year ended December 31, 2020 from $2.18 per Mcf for the year ended December 31, 2019. North America realized natural gas prices increased 15% to average $2.91 per Mcf for the fourth quarter of 2020 from $2.52 per Mcf for the fourth quarter of 2019, and increased 29% from $2.25 per Mcf for the third quarter of 2020. The increase in realized natural gas prices for the three months and year ended December 31, 2020 from the comparable periods primarily reflected lower production levels from the Basin.

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

	Three Months Ended		
(Quarterly average)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 38.03**	$ 36.48	$ 47.32
Pelican Lake heavy crude oil ($/bbl)	**$ 43.21**	$ 42.97	$ 51.66
Primary heavy crude oil ($/bbl)	**$ 42.01**	$ 42.63	$ 49.72
Bitumen (thermal oil) ($/bbl)	**$ 38.67**	$ 37.78	$ 42.93
Natural gas ($/Mcf)	**$ 2.91**	$ 2.25	$ 2.52

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

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

North Sea

North Sea realized crude oil prices decreased 42% to average $50.09 per bbl for the year ended December 31, 2020 from $86.76 per bbl for the year ended December 31, 2019. North Sea realized crude oil prices decreased 36% to average $56.18 per bbl for the fourth quarter of 2020 from $87.76 per bbl for the fourth quarter of 2019 and decreased 3% from $57.84 per bbl for the third quarter of 2020. Realized crude oil 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 decrease in realized crude oil prices for the three months and year ended December 31, 2020 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 prices decreased 39% to average $50.95 per bbl for the year ended December 31, 2020 from $83.68 per bbl for the year ended December 31, 2019. Offshore Africa realized crude oil prices decreased 31% to average $49.05 per bbl for the fourth quarter of 2020 from $70.73 per bbl for the fourth quarter of 2019 and decreased 11% from $55.11 per bbl for the third quarter of 2020. Realized crude oil 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 decrease in realized crude oil prices for the three months and year ended December 31, 2020 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 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 3.52**	$ 3.15	$ 6.52	**$ 2.72**	$ 6.56
North Sea	**$ 0.11**	$ 0.19	$ 0.13	**$ 0.12**	$ 0.16
Offshore Africa	**$ 2.11**	$ 2.42	$ 4.60	**$ 2.17**	$ 4.74
Average	**$ 3.34**	$ 3.03	$ 6.03	**$ 2.59**	$ 6.08
Natural gas ($/Mcf) (1)					
North America	**$ 0.13**	$ 0.07	$ 0.11	**$ 0.07**	$ 0.07
Offshore Africa	**$ 0.30**	$ 0.34	$ 0.39	**$ 0.37**	$ 0.63
Average	**$ 0.13**	$ 0.07	$ 0.11	**$ 0.08**	$ 0.08
Average ($/BOE) (1)	**$ 2.44**	$ 2.25	$ 4.37	**$ 1.89**	$ 4.09

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

North America

North America crude oil and natural gas royalties for the three months and year ended December 31, 2020 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates averaged approximately 9% of product sales for the year ended December 31, 2020 compared with 13% of product sales for the year ended December 31, 2019. Crude oil and NGLs royalty rates averaged approximately 9% of product sales for the fourth quarter of 2020 compared with 14% for the fourth quarter of 2019 and 8% for the third quarter of 2020. The decrease in royalty rates for the three months and year ended December 31, 2020 from the comparable periods in 2019 primarily reflected lower realized crude oil prices. The increase in the royalty rate for the fourth quarter of 2020 from the third quarter of 2020 primarily reflected higher realized crude oil prices in the fourth quarter of 2020.

Natural gas royalty rates averaged approximately 3% of product sales for the year ended December 31, 2020 compared with 3% of product sales for the year ended December 31, 2019. Natural gas royalty rates averaged approximately 4% of product sales for the fourth quarter of 2020 compared with 4% for the fourth quarter of 2019 and 3% for the third quarter of 2020. The increase in royalty rates for the fourth quarter of 2020 from the third quarter of 2020 primarily reflected higher realized natural gas 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 4% for the year ended December 31, 2020, compared with 6% of product sales for the year ended December 31, 2019. Royalty rates as a percentage of product sales averaged approximately 4% for the fourth quarter of 2020 compared with 6% of product sales for the fourth quarter of 2019 and 4% for the third quarter of 2020. 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 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 10.81**	$ 9.80	$ 10.74	**$ 11.21**	$ 12.41
North Sea	**$ 52.42**	$ 42.10	$ 33.67	**$ 36.51**	$ 36.39
Offshore Africa	**$ 11.74**	$ 16.41	$ 16.75	**$ 13.29**	$ 11.21
Average	**$ 12.47**	$ 11.03	$ 12.46	**$ 12.42**	$ 13.81
Natural gas ($/Mcf) (1)					
North America	**$ 1.07**	$ 1.14	$ 1.11	**$ 1.14**	$ 1.16
North Sea	**$ 5.29**	$ 5.38	$ 3.25	**$ 3.72**	$ 3.40
Offshore Africa	**$ 3.07**	$ 3.03	$ 3.19	**$ 3.58**	$ 2.60
Average	**$ 1.10**	$ 1.18	$ 1.17	**$ 1.18**	$ 1.22
Average ($/BOE) (1)	**$ 10.43**	$ 9.84	$ 10.79	**$ 10.67**	$ 11.49

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

North America

North America crude oil and NGLs production expense for the year ended December 31, 2020 averaged $11.21 per bbl, a decrease of 10% from $12.41 per bbl for the year ended December 31, 2019. North America crude oil and NGLs production expense for the fourth quarter of 2020 of $10.81 per bbl was comparable with $10.74 per bbl for the fourth quarter of 2019 and increased 10% from $9.80 per bbl for the third quarter of 2020. The decrease in crude oil and NGLs production expense per bbl for the year ended December 31, 2020 from 2019 primarily reflected the impact of increased thermal oil volumes, together with operating cost synergies at Jackfish. The increase in crude oil and NGLs production expense per bbl for the fourth quarter of 2020 from the third quarter of 2020 primarily reflected lower volumes as a result of the Company's curtailment optimization strategy, along with the impact of higher natural gas costs.

North America natural gas production expense for the year ended December 31, 2020 averaged $1.14 per Mcf, comparable with $1.16 per Mcf for the year ended December 31, 2019. North America natural gas production expense for the fourth quarter of 2020 of $1.07 per Mcf decreased 4% from $1.11 per Mcf for the fourth quarter of 2019 and decreased 6% from $1.14 per Mcf for the third quarter of 2020. The decrease in natural gas production expense per Mcf for the three months and year ended December 31, 2020 from the comparable periods primarily reflected the Company's strategy to own and control its infrastructure and its continued focus on cost control.

North Sea

North Sea crude oil production expense for the year ended December 31, 2020 averaged $36.51 per bbl, comparable with $36.39 per bbl for the year ended December 31, 2019. North Sea crude oil production expense for the fourth quarter of 2020 of $52.42 per bbl increased 56% from $33.67 per bbl for the fourth quarter of 2019 and increased 25% from $42.10 per bbl for the third quarter of 2020. The increase in crude oil production expense per bbl for the fourth quarter of 2020 from the comparable periods was primarily due to lower volumes, as a result of maintenance activities in the fourth quarter of 2020, on a relatively fixed cost base. The increase from the fourth quarter of 2019 also reflected fluctuations in the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the year ended December 31, 2020 averaged $13.29 per bbl, an increase of 19% from $11.21 per bbl for the year ended December 31, 2019. Offshore Africa crude oil production expense for the fourth quarter of 2020 of $11.74 per bbl decreased 30% from $16.75 per bbl for the fourth quarter of 2019 and decreased 28% from $16.41 per bbl for the third quarter of 2020. The increase in crude oil production expense per bbl for the year ended December 31, 2020 from 2019 was primarily due to lower volumes on a relatively fixed cost base. The decrease in crude oil production expense per bbl for the fourth quarter of 2020 from the comparable periods primarily reflected the timing of liftings from various fields that have different cost structures. Offshore Africa production expense also reflected fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Expense	**$ 1,132**	$ 1,046	$ 1,083	**$ 4,247**	$ 3,876
$/BOE (1)	**$ 15.55**	$ 15.01	$ 14.98	**$ 15.45**	$ 15.22

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

Depletion, depreciation and amortization expense for the year ended December 31, 2020 of $15.45 per BOE was comparable with $15.22 per BOE for the year ended December 31, 2019. Depletion, depreciation and amortization expense for the fourth quarter of 2020 of $15.55 per BOE increased 4% from $14.98 per BOE for the fourth quarter of 2019 and increased 4% from $15.01 per BOE for the third quarter of 2020. Fluctuations in depletion, depreciation and amortization expense from the comparable periods primarily reflected changes in product mix, fluctuating sales volumes from underlying operations, together with the impact of the acquisition of Painted Pony in the fourth quarter of 2020.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Expense	**$ 33**	$ 32	$ 36	**$ 133**	$ 129
$/BOE (1)	**$ 0.45**	$ 0.47	$ 0.49	**$ 0.48**	$ 0.51

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2020 of $0.48 per BOE decreased 6% from $0.51 per BOE for the year ended December 31, 2019. Asset retirement obligation accretion expense for the fourth quarter of 2020 of $0.45 per BOE decreased 8% from $0.49 per BOE for the fourth quarter of 2019 and decreased 4% from $0.47 per BOE for the third quarter of 2020. 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. Production in the fourth quarter of 2020 averaged 417,089 bbl/d, reflecting the ramp-up of production after the completion of expansion activities at AOSP and the successful planned maintenance activities at Horizon, as well as the impact of the Company's curtailment optimization strategy, including the suspension of mandatory Government of Alberta curtailment effective December 1, 2020.

The Company incurred production costs, excluding natural gas costs, of $2,968 million for the year ended December 31, 2020, a $183 million, or 6% decrease from the year ended December 31, 2019.

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

	Three Months Ended			Year Ended	
($/bbl) [1]	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
SCO realized sales price [2]	**$ 48.56**	$ 48.92	$ 68.67	**$ 43.98**	$ 70.18
Bitumen value for royalty purposes [3]	**$ 34.70**	$ 36.26	$ 44.88	**$ 25.82**	$ 50.79
Bitumen royalties [4]	**$ 0.59**	$ 0.46	$ 3.47	**$ 0.51**	$ 3.31
Transportation	**$ 1.36**	$ 1.30	$ 1.33	**$ 1.23**	$ 1.29

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

(2) Net of blending and feedstock costs.

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

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

The realized SCO sales price averaged $43.98 per bbl for the year ended December 31, 2020, a decrease of 37% from $70.18 per bbl for the year ended December 31, 2019. For the fourth quarter of 2020, the realized sales price decreased 29% to $48.56 per bbl from $68.67 per bbl for the fourth quarter of 2019 and was comparable with $48.92 per bbl for the third quarter of 2020. The decrease in the realized SCO sales price for the three months and year ended December 31, 2020 from the comparable periods in 2019 primarily reflected decreases in WTI benchmark pricing.

Transportation expense averaged $1.23 per bbl for the year ended December 31, 2020, comparable with $1.29 per bbl for the year ended December 31, 2019. For the fourth quarter of 2020, transportation expense of $1.36 per bbl, was comparable with $1.33 per bbl for the fourth quarter of 2019 and comparable with $1.30 per bbl for the third quarter of 2020.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 18 to the Company’s unaudited interim consolidated financial statements.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Production costs, excluding natural gas costs	**$ 736**	$ 760	$ 814	**$ 2,968**	$ 3,151
Natural gas costs	**51**	28	42	**146**	125
Production costs	**$ 787**	$ 788	$ 856	**$ 3,114**	$ 3,276

	Three Months Ended			Year Ended	
($/bbl) [1]	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Production costs, excluding natural gas costs	**$ 18.89**	$ 22.96	$ 23.86	**$ 19.50**	$ 21.70
Natural gas costs	**1.31**	0.85	1.23	**0.96**	0.86
Production costs	**$ 20.20**	$ 23.81	$ 25.09	**$ 20.46**	$ 22.56
Sales (bbl/d)	**423,438**	359,479	370,468	**415,741**	397,735

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

Production costs for the year ended December 31, 2020 decreased by $2.10 per bbl or 9% to $20.46 per bbl from $22.56 per bbl for the year ended December 31, 2019. Production costs for the fourth quarter of 2020 averaged $20.20 per bbl, a decrease of $4.89 per bbl or 19% from $25.09 per bbl for the fourth quarter of 2019 and a decrease of $3.61 per bbl or 15% from $23.81 per bbl for the third quarter of 2020.

The decrease in production costs per bbl for the three months and year ended December 31, 2020 from the comparable periods primarily reflected high reliability and operational enhancements at both Horizon and AOSP. The Company continued to focus on cost control and efficiencies across the entire asset base.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Expense	**$ 479**	$ 414	$ 464	**$ 1,784**	$ 1,656
$/bbl (1)	**$ 12.31**	$ 12.51	$ 13.61	**$ 11.73**	$ 11.41

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

Depletion, depreciation and amortization expense for the year ended December 31, 2020 of $11.73 per bbl was comparable with $11.41 per bbl for the year ended December 31, 2019. Depletion, depreciation and amortization expense for the fourth quarter of 2020 of $12.31 per bbl decreased 10% from $13.61 per bbl for the fourth quarter of 2019, and was comparable with $12.51 per bbl for the third quarter of 2020. Fluctuations in depletion, depreciation and amortization on a per barrel basis primarily reflect fluctuating sales volumes from different underlying operations.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Expense	**$ 18**	$ 19	$ 14	**$ 72**	$ 61
$/bbl (1)	**$ 0.47**	$ 0.55	$ 0.44	**$ 0.47**	$ 0.42

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2020 of $0.47 per bbl increased 12% from $0.42 per bbl for the year ended December 31, 2019. Asset retirement obligation accretion expense of $0.47 per bbl for the fourth quarter of 2020 increased 7% from $0.44 per bbl for the fourth quarter of 2019 and decreased 15% from $0.55 per bbl for the third quarter of 2020. 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 2020**	Sep 30 2020	Dec 31 2019	Year Ended **Dec 31 2020**	Dec 31 2019
Product sales					
Crude oil and NGLs, midstream activities	**$ 21**	$ 21	$ 26	**$ 83**	$ 88
NWRP, refined product sales	**99**	78	—	**202**	—
Segmented revenue	**120**	99	26	**285**	88
Less:					
Production expenses					
NWRP, refining toll	**72**	70	—	**166**	—
Midstream	**3**	4	5	**18**	20
NWRP, transportation and feedstock costs	**83**	76	—	**181**	—
Depreciation	**4**	4	3	**15**	14
Equity loss from investment in NWRP	**—**	—	73	**—**	287
Segmented loss before taxes	**$ (42)**	$ (55)	$ (55)	**$ (95)**	$ (233)

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% interest in NWRP.

NWRP operates a 50,000 bbl/d bitumen upgrader and refinery that targets to process 12,500 bbl/d of bitumen feedstock for the Company and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission, an agent of the Government of Alberta, under a 30-year fee-for-service tolling agreement.

On June 1, 2020, the refinery achieved the Commercial Operation Date, pursuant to the terms of the tolling agreement. The Company is unconditionally obligated to pay its 25% pro rata share of the debt tolls over the 30-year tolling period. For the three months ended December 31, 2020, production of ultra-low sulphur diesel and other refined products averaged 65,670 BOE/d (16,417 BOE/d to the Company).

The Company's unrecognized share of the equity (income) loss from NWRP for the three months ended December 31, 2020 was a recovery of unrecognized losses of $6 million (year ended December 31, 2020 – unrecognized equity loss of $94 million; December 31, 2019 – recognized equity loss of $287 million and unrecognized equity loss of $59 million). As at December 31, 2020, the cumulative unrecognized share of losses from NWRP was $153 million (December 31, 2019 – $59 million).

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended **Dec 31 2020**	Sep 30 2020	Dec 31 2019	Year Ended **Dec 31 2020**	Dec 31 2019
Expense	**$ 107**	$ 88	$ 95	**$ 391**	$ 344
$/BOE (1)	**$ 0.96**	$ 0.85	$ 0.90	**$ 0.92**	$ 0.86

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

Administration expense for the year ended December 31, 2020 of $0.92 per BOE increased 7% from $0.86 per BOE for the year ended December 31, 2019. Administration expense for the fourth quarter of 2020 of $0.96 per BOE increased 7% from $0.90 per BOE for the fourth quarter of 2019 and increased 13% from $0.85 per BOE for the third quarter of 2020. Administration expense per BOE increased for the year ended December 31, 2020 from 2019 primarily due to lower overhead recoveries and increased corporate and personnel costs. Administration expense per BOE increased for the fourth quarter of 2020 from the fourth quarter of 2019 primarily due to lower overhead recoveries and increased corporate costs, partially offset by the impact of lower personnel costs. The increase in administration expense per BOE for the fourth quarter of 2020 from the third quarter of 2020 was primarily due to higher personnel and corporate costs, partially offset by the impact of higher overhead recoveries.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended **Dec 31 2020**	Sep 30 2020	Dec 31 2019	Year Ended **Dec 31 2020**	Dec 31 2019
Expense (recovery)	**$ 123**	$ (5)	$ 161	**$ (82)**	$ 223

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

The Company recognized an $82 million share-based compensation recovery for the year ended December 31, 2020, primarily as a result of the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period, and changes in the Company’s share price. Included within the share-based compensation recovery for the year ended December 31, 2020 was an expense of $21 million related to PSUs granted to certain executive employees (December 31, 2019 – $49 million expense). For the year ended December 31, 2020, the Company charged $5 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (December 31, 2019 – $5 million charged).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended **Dec 31 2020**	Sep 30 2020	Dec 31 2019	Year Ended **Dec 31 2020**	Dec 31 2019
Expense, gross	**$ 180**	$ 180	$ 225	**$ 780**	$ 889
Less: capitalized interest	**3**	6	8	**24**	53
Expense, net	**$ 177**	$ 174	$ 217	**$ 756**	$ 836
$/BOE (1)	**$ 1.59**	$ 1.69	$ 2.04	**$ 1.77**	$ 2.09
Average effective interest rate	**3.3%**	3.4%	3.9%	**3.5%**	4.0%

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

Gross interest and other financing expense for the three months and year ended December 31, 2020 decreased from the comparable periods in 2019 primarily due to lower interest rates. Capitalized interest of $24 million for the year ended December 31, 2020 was related to residual project activities at Horizon.

Net interest and other financing expense per BOE for the year ended December 31, 2020 decreased 15% to $1.77 per BOE from $2.09 per BOE for the year ended December 31, 2019. Net interest and other financing expense per BOE for the fourth quarter of 2020 decreased 22% to $1.59 per BOE from $2.04 per BOE for the fourth quarter of 2019 and decreased 6% from $1.69 per BOE for the third quarter of 2020. The decrease in net interest and other financing expense per BOE for the three months and year ended December 31, 2020 from the comparable periods was primarily due to lower average interest rates.

The Company’s average effective interest rate for the fourth quarter of 2020 decreased from the comparable periods primarily due to the impact of lower benchmark interest rates on the Company's outstanding bank credit facilities and US commercial paper program.

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 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Foreign currency contracts	**$ 25**	$ 20	$ 5	**$ 16**	$ 13
Natural gas financial instruments	**(2)**	5	6	**16**	(1)
Crude oil and NGLs financial instruments	**—**	—	—	**—**	52
Net realized loss	**23**	25	11	**32**	64
Foreign currency contracts	**6**	—	10	**(3)**	15
Natural gas financial instruments	**(27)**	(2)	7	**(36)**	15
Crude oil and NGLs financial instruments	**—**	—	—	**—**	(17)
Net unrealized (gain) loss	**(21)**	(2)	17	**(39)**	13
Net loss (gain)	**$ 2**	$ 23	$ 28	**$ (7)**	$ 77

During the year ended December 31, 2020, net realized risk management losses were related to the settlement of foreign currency contracts and natural gas financial instruments. The Company recorded a net unrealized gain of $39 million ($31 million after-tax) on its risk management activities for the year ended December 31, 2020, including the impact of natural gas financial instruments from the Painted Pony acquisition in the fourth quarter of 2020. It also included an unrealized gain of $21 million ($16 million after-tax) for the fourth quarter of 2020 (September 30, 2020 – unrealized gain of $2 million, $1 million after-tax; December 31, 2019 – unrealized loss of $17 million, $16 million after-tax).

Further details related to outstanding derivative financial instruments at December 31, 2020 are disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Net realized loss (gain)	**$ 21**	$ 16	$ (4)	**$ (159)**	$ (22)
Net unrealized gain	**(534)**	(270)	(225)	**(116)**	(548)
Net gain (1)	**$ (513)**	$ (254)	$ (229)	**$ (275)**	$ (570)

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

The net realized foreign exchange gain for the year ended December 31, 2020 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the settlement of the US$500 million cross currency swaps during the first quarter of 2020. The net unrealized foreign exchange gain for the year ended December 31, 2020 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized gain for each of the periods presented reflected the impact of the cross currency swaps, including the settlement of US$500 million in cross currency swaps in the first quarter of 2020 (three months ended December 31, 2020 – unrealized loss of $32 million, September 30, 2020 – unrealized loss of $16 million, December 31, 2019 – unrealized loss of $29 million; year ended December 31, 2020 – unrealized loss of $150 million, December 31, 2019 – unrealized loss of $71 million). The US/Canadian dollar exchange rate at December 31, 2020 was US$0.7840 (September 30, 2020 – US$0.7505, December 31, 2019 – US$0.7713).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Dec 31 2020**	Sep 30 2020	Dec 31 2019	Year Ended **Dec 31 2020**	Dec 31 2019
North America [1]	**$ 42**	$ (59)	$ (20)	**$ (245)**	$ 354
North Sea	**—**	(14)	40	**(4)**	112
Offshore Africa	**5**	6	7	**17**	44
PRT [2] – North Sea	**(14)**	(17)	—	**(31)**	(89)
Other taxes	**2**	2	4	**6**	13
Current income tax expense (recovery)	**35**	(82)	31	**(257)**	434
Deferred corporate income tax (recovery) expense	**(25)**	91	194	**(181)**	(895)
Deferred PRT [2] – North Sea	**—**	—	—	**—**	1
Deferred income tax (recovery) expense	**(25)**	91	194	**(181)**	(894)
Income tax expense (recovery)	**10**	9	225	**(438)**	(460)
Income tax rate and other legislative changes	**—**	—	—	**—**	1,618
	$ 10	$ 9	$ 225	**$ (438)**	$ 1,158
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**24%**	15%	26%	**34%**	25%

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

(2) Petroleum Revenue Tax.

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

The effective income tax rate for the three months and year ended December 31, 2020 and the comparable periods included the impact of non-taxable items in North America and 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 year ended December 31, 2020 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.

In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of this corporate income tax rate reduction, the Company's deferred corporate income tax liability decreased by $1,618 million for the year ended December 31, 2019. In the fourth quarter of 2020, the Government of Alberta substantively enacted legislation to accelerate this reduction, lowering the corporate tax rate from 10% to 8%, effective July 1, 2020. This acceleration did not have a significant impact on the Company's deferred corporate income tax liability for the year ended December 31, 2020.

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

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Dec 31 2020	Three Months Ended Sep 30 2020	Three Months Ended Dec 31 2019	Year Ended Dec 31 2020	Year Ended Dec 31 2019
Exploration and Evaluation					
Net property (dispositions) acquisitions [2]	**$ (1)**	$ (12)	$ —	**$ (31)**	$ 90
Net expenditures	**9**	1	—	**36**	74
Total Exploration and Evaluation	**8**	(11)	—	**5**	164
Property, Plant and Equipment					
Net property acquisitions (dispositions) [2] [3]	**522**	(1)	20	**536**	3,208
Well drilling, completion and equipping	**115**	80	169	**429**	775
Production and related facilities	**131**	157	238	**580**	1,028
Capitalized interest and other	**20**	14	15	**60**	81
Total Property, Plant and Equipment	**788**	250	442	**1,605**	5,092
Total Exploration and Production	**796**	239	442	**1,610**	5,256
Oil Sands Mining and Upgrading					
Project costs	**86**	67	121	**258**	436
Sustaining capital	**212**	254	334	**839**	933
Turnaround costs	**22**	131	57	**196**	118
Capitalized interest and other	**4**	8	9	**30**	38
Total Oil Sands Mining and Upgrading	**324**	460	521	**1,323**	1,525
Midstream and Refining	**1**	1	1	**5**	10
Abandonments [4]	**52**	68	84	**249**	296
Head office	**3**	3	8	**19**	34
Total net capital expenditures	**$ 1,176**	$ 771	$ 1,056	**$ 3,206**	$ 7,121
By segment					
North America [2] [3]	**$ 729**	$ 170	$ 330	**$ 1,389**	$ 4,831
North Sea	**34**	45	63	**122**	196
Offshore Africa	**33**	24	49	**99**	229
Oil Sands Mining and Upgrading	**324**	460	521	**1,323**	1,525
Midstream and Refining	**1**	1	1	**5**	10
Abandonments [4]	**52**	68	84	**249**	296
Head office	**3**	3	8	**19**	34
Total	**$ 1,176**	$ 771	$ 1,056	**$ 3,206**	$ 7,121

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

(2) Includes cash consideration paid of $91 million for exploration and evaluation assets and $3,126 million for property, plant and equipment acquired from Devon in the second quarter of 2019.

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

(4) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Cash flows used in investing activities	***$ 624***	*$ 643*	*$ 854*	***$ 2,819***	*$ 7,255*
Net change in non-cash working capital (1)	***(21)***	*60*	*118*	***(383)***	*(430)*
Repayment of NWRP subordinated debt advances (2)	***124***	*—*	*—*	***124***	*—*
Abandonment expenditures (3)	***52***	*68*	*84*	***249***	*296*
Other (4)	***397***	*—*	*—*	***397***	*—*
Net capital expenditures	***$ 1,176***	*$ 771*	*$ 1,056*	***$ 3,206***	*$ 7,121*

(1) Includes net working capital and other long-term assets of $195 million related to the acquisition of assets from Devon in the second quarter of 2019.

(2) Relates to a partial repayment of the Company's subordinated debt advances to NWRP.

(3) The Company excludes abandonment expenditures from "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" in the "Financial Highlights" section of this MD&A.

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

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 development 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.

On October 6, 2020, the Company completed the acquisition of all of the issued and outstanding common shares of Painted Pony for net cash consideration of approximately $111 million. At closing, the acquisition also included the assumption of long-term debt of approximately $397 million.

Capital expenditures totaled $1,176 million for the fourth quarter of 2020 and $3,206 million for the year ended December 31, 2020. Capital expenditures excluding the impact of the acquisition of Painted Pony in the fourth quarter of 2020 were $2,698 million for the year ended December 31, 2020, reflecting the Company's flexible and disciplined approach.

2021 Capital Budget

On December 9, 2020, the Company announced its 2021 capital budget targeted at approximately $3,205 million, of which $1,345 million is related to conventional and unconventional assets and $1,860 million is allocated to long-life low decline assets.

Drilling Activity (1)

	Three Months Ended			Year Ended	
(number of net wells)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Net successful natural gas wells	**9**	9	4	**30**	19
Net successful crude oil wells (2)	**5**	—	12	**42**	86
Dry wells	**—**	—	—	**—**	3
Stratigraphic test / service wells	**—**	1	89	**372**	447
Total	**14**	10	105	**444**	555
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	100%	**100%**	97%

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

(2) Includes bitumen wells.

North America

During the fourth quarter of 2020, the Company targeted 9 net natural gas wells and 5 net light crude oil wells.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019
Working capital (1)	**$ 626**	$ 707	$ 241
Long-term debt (2) (3)	**$ 21,453**	$ 21,876	$ 20,982
Less: cash and cash equivalents	**184**	175	139
Long-term debt, net	**$ 21,269**	$ 21,701	$ 20,843
Share capital	**$ 9,606**	$ 9,522	$ 9,533
Retained earnings	**22,766**	22,520	25,424
Accumulated other comprehensive income	**8**	124	34
Shareholders' equity	**$ 32,380**	$ 32,166	$ 34,991
Debt to book capitalization (3) (4)	**39.6%**	40.3%	37.3%
Debt to market capitalization (3) (5)	**37.0%**	46.3%	29.5%
After-tax return on average common shareholders' equity (6)	**(1.3)%**	(1.8)%	16.1%
After-tax return on average capital employed (3) (7)	**0.2 %**	0.0%	10.9%

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

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

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

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

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

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

(7) Calculated as net earnings (loss) plus after-tax interest and other financing expense for the twelve month trailing period; as a percentage of average capital employed (defined as current and long-term debt plus shareholders' equity) for the twelve month trailing period.

As at December 31, 2020, 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, 2019. 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 that 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 2020, the Company issued $500 million of 1.45% notes due November 2023 and $300 million of 2.50% notes due January 2028. After issuing these securities, the Company had $2,200 million remaining on its 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 2021. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
  - During the second quarter of 2020, the Company issued US$600 million of 2.05% notes due July 2025 and US$500 million of 2.95% notes due July 2030. After issuing these securities, the Company had US$1,900 million remaining on its 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 2021. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
  - During the third quarter of 2020, the Company repaid $1,000 million of 2.89% medium-term notes.
  - During the second quarter of 2020, the Company repaid $900 million of 2.05% medium-term notes.
  - Each of the Company's $2,425 million revolving credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
  - Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2020, the non-revolving term credit facilities were fully drawn.
  - During the second quarter of 2020, the $750 million non-revolving term credit facility, originally due February 2021, was extended to February 2022 and increased to $1,000 million. Subsequent to December 31, 2020, the facility was extended to February 2023.
  - During 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. During the second quarter of 2020, the Company repaid $162.5 million related to the required annual amortization, reducing the facility balance to $3,088 million. Subsequent to December 31, 2020, the Company repaid a further $362.5 million on the facility, reducing the outstanding balance to $2,725 million, and satisfying the required annual amortization of $162.5 million originally due in June 2021. The facility matures in June 2022.
  - 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, 2020, the Company had undrawn revolving bank credit facilities of $4,958 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,447 million in liquidity. Additionally, the Company had in place fully drawn term credit facilities of $6,738 million. The Company also has certain other dedicated credit facilities supporting letters of credit. At December 31, 2020, the Company had $544 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

As at December 31, 2020, the Company had total US dollar denominated debt with a carrying amount of $16,746 million (US$13,129 million), before transaction costs and original issue discounts. This included $6,287 million (US$4,929 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$4,379 million). The fixed repayment amount of these hedging instruments is $6,337 million, resulting in a notional increase of the carrying amount of the Company’s US dollar denominated debt by approximately $50 million to $16,796 million as at December 31, 2020.

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.

Net long-term debt was $21,269 million at December 31, 2020, resulting in a debt to book capitalization ratio of 39.6% (December 31, 2019 – 37.3%); 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, 2020 are discussed in note 9 of the Company's unaudited interim consolidated financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2020, 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, 2020 are discussed in note 16 of the Company's unaudited interim consolidated financial statements.

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]	$ 1,343	$ 4,887	$ 7,051	$ 8,279
Other long-term liabilities [2]	$ 345	$ 200	$ 435	$ 942
Interest and other financing expense [3]	$ 776	$ 693	$ 1,619	$ 4,452

(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, $189 million; one to less than two years, $162 million; two to less than five years, $397 million; and thereafter, $942 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2020.

Share Capital

As at December 31, 2020, there were 1,183,866,000 common shares outstanding (December 31, 2019 – 1,186,857,000 common shares) and 48,656,000 stock options outstanding. As at March 2, 2021, the Company had 1,185,574,000 common shares outstanding and 53,829,000 stock options outstanding.

On March 3, 2021, the Board of Directors approved an increase in the quarterly dividend to $0.47 per common share, beginning with the dividend payable on April 5, 2021. On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to $0.425 per common share (previous quarterly dividend rate of $0.375 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 21, 2019, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company did not renew its Normal Course Issuer Bid after its expiry in May 2020.

During the first quarter of 2020, the Company purchased 6,970,000 common shares at a weighted average price of $38.84 per common share for a total cost of $271 million. Retained earnings were reduced by $215 million, representing the excess of the purchase price of common shares over their average carrying value.

On March 3, 2021, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the Toronto Stock Exchange ("TSX") to purchase, by way of a normal course issuer bid, up to 5.0% of its issued and outstanding common shares for the purpose of repurchasing a number of common shares approximately equal to the number of options exercised throughout the year in order to eliminate dilution for shareholders. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through the facilities of the TSX, alternative Canadian trading platforms and the New York Stock Exchange.

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, 2020:

($ millions)		2021		2022		2023		2024		2025		Thereafter
Product transportation and processing (1) (2)	$	870	$	817	$	858	$	841	$	809	$	10,370
North West Redwater Partnership service toll (3)	$	163	$	160	$	160	$	156	$	150	$	2,694
Offshore vessels and equipment	$	64	$	9	$	—	$	—	$	—	$	—
Field equipment and power	$	28	$	21	$	21	$	21	$	21	$	246
Other	$	25	$	21	$	21	$	22	$	22	$	16

(1) Includes commitments pertaining to a 20-year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals.

(2) The acquisition of Painted Pony in the fourth quarter of 2020 included approximately $2,400 million of product transportation and processing commitments.

(3) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt component of the monthly cost of service tolls. Included in the cost of service tolls is $1,169 million of interest payable over the 30-year tolling period.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

ACCOUNTING POLICIES

Government Grants

The Company receives or is eligible for government grants, including those introduced in response to the impact of COVID-19. Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to the grant and the grant will be received. Grants that are intended to compensate for expenses incurred are classified as other income.

Changes in Accounting Policies

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments apply to business combinations after the date of adoption. The Company prospectively adopted the amendments on January 1, 2020.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS standards. Materiality is used in making judgements related to the preparation of financial statements. The Company prospectively adopted the amendments on January 1, 2020.

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, 2020, COVID-19 had an impact on the global economy, including the oil and gas industry. Business conditions in the fourth quarter of 2020 continued to reflect the market uncertainty associated with COVID-19, with some modest improvements to global crude oil demand and supply conditions. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions, and judgements in the preparation of the unaudited interim consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the Company's annual MD&A and audited consolidated financial statements for the year ended December 31, 2019.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the year ended December 31, 2020 that have materially affected, or are reasonably likely to materially affect the Company’s ICFR. Due to inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Dec 31 2020**	Dec 31 2019
ASSETS			
Current assets			
Cash and cash equivalents		**$ 184**	$ 139
Accounts receivable		**2,190**	2,465
Current income taxes receivable		**309**	13
Inventory		**1,060**	1,152
Prepaids and other		**231**	174
Investments	7	**305**	490
Current portion of other long-term assets	8	**82**	54
		4,361	4,487
Exploration and evaluation assets	4	**2,436**	2,579
Property, plant and equipment	5	**65,752**	68,043
Lease assets	6	**1,645**	1,789
Other long-term assets	8	**1,082**	1,223
		$ 75,276	$ 78,121
LIABILITIES			
Current liabilities			
Accounts payable		**$ 667**	$ 816
Accrued liabilities		**2,346**	2,611
Current portion of long-term debt	9	**1,343**	2,391
Current portion of other long-term liabilities	6,10	**722**	819
		5,078	6,637
Long-term debt	9	**20,110**	18,591
Other long-term liabilities	6,10	**7,564**	7,363
Deferred income taxes		**10,144**	10,539
		42,896	43,130
SHAREHOLDERS' EQUITY			
Share capital	12	**9,606**	9,533
Retained earnings		**22,766**	25,424
Accumulated other comprehensive income	13	**8**	34
		32,380	34,991
		$ 75,276	$ 78,121

Commitments and contingencies (note 17).

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

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Dec 31 2020	Three Months Ended Dec 31 2019	Year Ended Dec 31 2020	Year Ended Dec 31 2019
Product sales	18	**$ 5,219**	$ 6,335	**$ 17,491**	$ 24,394
Less: royalties		**(201)**	(434)	**(598)**	(1,523)
Revenue		**5,018**	5,901	**16,893**	22,871
Expenses					
Production		**1,631**	1,648	**6,280**	6,277
Transportation, blending and feedstock		**1,318**	1,416	**4,498**	4,699
Depletion, depreciation and amortization	5,6	**1,615**	1,550	**6,046**	5,546
Administration		**107**	95	**391**	344
Share-based compensation	10	**123**	161	**(82)**	223
Asset retirement obligation accretion	10	**51**	50	**205**	190
Interest and other financing expense		**177**	217	**756**	836
Risk management activities	16	**2**	28	**(7)**	77
Foreign exchange gain		**(513)**	(229)	**(275)**	(570)
Gain on acquisition	5	**(217)**	—	**(217)**	—
(Gain) loss from investments	7,8	**(35)**	143	**171**	293
		4,259	5,079	**17,766**	17,915
Earnings (loss) before taxes		**759**	822	**(873)**	4,956
Current income tax expense (recovery)	11	**35**	31	**(257)**	434
Deferred income tax (recovery) expense	11	**(25)**	194	**(181)**	(894)
Net earnings (loss)		**$ 749**	$ 597	**$ (435)**	$ 5,416
Net earnings (loss) per common share					
Basic	15	**$ 0.63**	$ 0.50	**$ (0.37)**	$ 4.55
Diluted	15	**$ 0.63**	$ 0.50	**$ (0.37)**	$ 4.54

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2020	Three Months Ended Dec 31 2019	Year Ended Dec 31 2020	Year Ended Dec 31 2019
Net earnings (loss)	**$ 749**	$ 597	**$ (435)**	$ 5,416
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 $nil (2019 – $1 million) – three months ended; $2 million (2019 – $13 million) – year ended	**(4)**	2	**13**	99
Reclassification to net earnings (loss), net of taxes of $nil (2019 – $nil) – three months ended; $2 million (2019 – $5 million) – year ended	**(2)**	(5)	**(15)**	(41)
	(6)	(3)	**(2)**	58
Foreign currency translation adjustment				
Translation of net investment	**(110)**	(61)	**(24)**	(146)
Other comprehensive loss, net of taxes	**(116)**	(64)	**(26)**	(88)
Comprehensive income (loss)	**$ 633**	$ 533	**$ (461)**	$ 5,328

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended Dec 31 2020	Dec 31 2019
Share capital	12		
Balance – beginning of year		**$ 9,533**	$ 9,323
Issued upon exercise of stock options		**108**	360
Previously recognized liability on stock options exercised for common shares		**21**	53
Purchase of common shares under Normal Course Issuer Bid		**(56)**	(203)
Balance – end of year		**9,606**	9,533
Retained earnings			
Balance – beginning of year		**25,424**	22,529
Net earnings (loss)		**(435)**	5,416
Dividends on common shares	12	**(2,008)**	(1,783)
Purchase of common shares under Normal Course Issuer Bid	12	**(215)**	(738)
Balance – end of year		**22,766**	25,424
Accumulated other comprehensive income	13		
Balance – beginning of year		**34**	122
Other comprehensive loss, net of taxes		**(26)**	(88)
Balance – end of year		**8**	34
Shareholders' equity		**$ 32,380**	$ 34,991

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Dec 31 2020	Three Months Ended Dec 31 2019	Year Ended Dec 31 2020	Year Ended Dec 31 2019
Operating activities					
Net earnings (loss)		**$ 749**	$ 597	**$ (435)**	$ 5,416
Non-cash items					
Depletion, depreciation and amortization		**1,615**	1,550	**6,046**	5,546
Share-based compensation		**123**	161	**(82)**	223
Asset retirement obligation accretion		**51**	50	**205**	190
Unrealized risk management (gain) loss		**(21)**	17	**(39)**	13
Unrealized foreign exchange gain		**(534)**	(225)	**(116)**	(548)
Realized foreign exchange gain on settlement of cross currency swaps		**—**	—	**(166)**	—
Gain on acquisition	5	**(217)**	—	**(217)**	—
(Gain) loss from investments	7,8	**(33)**	150	**185**	321
Deferred income tax (recovery) expense		**(25)**	194	**(181)**	(894)
Other		**8**	(8)	**(71)**	(109)
Abandonment expenditures		**(52)**	(84)	**(249)**	(296)
Net change in non-cash working capital		**(394)**	52	**(166)**	(1,033)
Cash flows from operating activities		**1,270**	2,454	**4,714**	8,829
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net	9	**(563)**	(701)	**338**	2,025
Issue (repayment) of medium-term notes	9	**800**	(500)	**(1,100)**	(1,000)
Issue of US dollar debt securities	9	**—**	—	**1,481**	—
Settlement of Painted Pony long-term debt	5	**(397)**	—	**(397)**	—
Proceeds on settlement of cross currency swaps	16	**—**	—	**166**	—
Payment of lease liabilities	6,10	**(47)**	(64)	**(225)**	(237)
Issue of common shares on exercise of stock options		**72**	212	**108**	360
Dividends on common shares		**(502)**	(444)	**(1,950)**	(1,743)
Purchase of common shares under Normal Course Issuer Bid	12	**—**	(140)	**(271)**	(941)
Cash flows used in financing activities		**(637)**	(1,637)	**(1,850)**	(1,536)
Investing activities					
Net expenditures on exploration and evaluation assets	4,18	**(8)**	—	**(5)**	(73)
Net expenditures on property, plant and equipment	5,18	**(719)**	(972)	**(2,555)**	(3,535)
Acquisition of Devon assets		**—**	—	**—**	(3,412)
Repayment of NWRP subordinated debt advances	8	**124**	—	**124**	—
Net change in non-cash working capital		**(21)**	118	**(383)**	(235)
Cash flows used in investing activities		**(624)**	(854)	**(2,819)**	(7,255)
Increase (decrease) in cash and cash equivalents		**9**	(37)	**45**	38
Cash and cash equivalents – beginning of period		**175**	176	**139**	101
Cash and cash equivalents – end of period		**$ 184**	$ 139	**$ 184**	$ 139
Interest paid on long-term debt, net		**$ 147**	$ 191	**$ 745**	$ 865
Income taxes paid (received)		**$ —**	$ 73	**$ (29)**	$ 445

(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 ("UK") 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, 2019, 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 that are 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, 2019.

Critical Accounting Estimates and Judgements

For the three months and year ended December 31, 2020, the novel coronavirus ("COVID-19") had an impact on the global economy, including the oil and gas industry. Business conditions in the fourth quarter of 2020 continued to reflect the market uncertainty associated with COVID-19, with some modest improvements to global crude oil demand and supply conditions. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions and judgements in the preparation of the unaudited interim consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Actual results may differ from estimated amounts, and those differences may be material.

Government Grants

The Company receives or is eligible for government grants, including those introduced in response to the impact of COVID-19. Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to the grant and the grant will be received. Grants that are intended to compensate for expenses incurred are classified as other income.

2. CHANGES IN ACCOUNTING POLICIES

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments apply to business combinations after the date of adoption. The Company prospectively adopted the amendments on January 1, 2020.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS Standards. Materiality is used in making judgements related to the preparation of financial statements. The Company prospectively adopted the amendments on January 1, 2020.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In January 2020, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" to clarify that liabilities are classified as either current or non-current, depending on the existence of the substantive right at the end of the reporting period for an entity to defer settlement of the liability for at least twelve months after the reporting period. The amendments are effective January 1, 2023 with early adoption permitted. The amendments are required to be adopted retrospectively. The Company is assessing the impact of these amendments on its consolidated financial statements.

In May 2020, the IASB issued amendments to IAS 16 “Property, Plant and Equipment” to require proceeds received from selling items produced while the entity is preparing the asset for its intended use to be recognized in net earnings, rather than as a reduction in the cost of the asset. The amendments are effective January 1, 2022 with early adoption permitted. The Company is assessing the impact of these amendments on its consolidated financial statements.

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 amendments are effective for annual periods beginning on or after January 1, 2021 and are to be applied retrospectively, with early adoption permitted. The Company is assessing the impact of IBOR reform and the IASB amendments and does not expect that these amendments will have a significant impact on the Company's financial statements.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2019	$ 2,258	$ —	$ 69	$ 252	$ 2,579
Additions/acquisitions	**40**	**—**	**15**	**—**	**55**
Transfers to property, plant and equipment	**(194)**	**—**	**—**	**—**	**(194)**
Derecognitions and other	**(3)**	**—**	**—**	**—**	**(3)**
Foreign exchange adjustments	**—**	**—**	**(1)**	**—**	**(1)**
At December 31, 2020	**$ 2,101**	**$ —**	**$ 83**	**$ 252**	**$ 2,436**

5. 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, 2019	$ 72,627	$ 7,296	$ 3,933	$ 45,016	$ 451	$ 466	$ 129,789
Additions/acquisitions	**1,789**	**104**	**94**	**1,328**	**6**	**19**	**3,340**
Transfers from E&E assets	**194**	**—**	**—**	**—**	**—**	**—**	**194**
Derecognitions	**(521)**	**(3)**	**—**	**(634)**	**—**	**—**	**(1,158)**
Disposals	**(92)**	**—**	**—**	**—**	**—**	**—**	**(92)**
Foreign exchange adjustments and other	**—**	**(114)**	**(64)**	**—**	**—**	**—**	**(178)**
At December 31, 2020	**$ 73,997**	**$ 7,283**	**$ 3,963**	**$ 45,710**	**$ 457**	**$ 485**	**$ 131,895**
Accumulated depletion and depreciation							
At December 31, 2019	$ 46,577	$ 5,712	$ 2,712	$ 6,247	$ 153	$ 345	$ 61,746
Expense	**3,676**	**247**	**161**	**1,668**	**15**	**25**	**5,792**
Derecognitions	**(521)**	**(3)**	**—**	**(634)**	**—**	**—**	**(1,158)**
Disposals	**(63)**	**—**	**—**	**—**	**—**	**—**	**(63)**
Foreign exchange adjustments and other	**(28)**	**(103)**	**(51)**	**8**	**—**	**—**	**(174)**
At December 31, 2020	**$ 49,641**	**$ 5,853**	**$ 2,822**	**$ 7,289**	**$ 168**	**$ 370**	**$ 66,143**
Net book value							
- at December 31, 2020	**$ 24,356**	**$ 1,430**	**$ 1,141**	**$ 38,421**	**$ 289**	**$ 115**	**$ 65,752**
- at December 31, 2019	$ 26,050	$ 1,584	$ 1,221	$ 38,769	$ 298	$ 121	$ 68,043

On October 6, 2020, the Company completed the acquisition of all the issued and outstanding shares of Painted Pony Energy Ltd. ("Painted Pony") for total cash consideration of $111 million. Painted Pony is involved in the exploration for and development of natural gas and natural gas liquids in Northeast 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	**$ 750**
Exploration and evaluation assets	**15**
Other long-term assets	**204**
Long-term debt	**(397)**
Asset retirement obligations	**(13)**
Other long-term liabilities	**(442)**
Deferred tax asset	**211**
Net assets acquired	**328**
Less: cash consideration	**111**
Gain on acquisition [(1)]	**$ 217**

(1) The gain on acquisition of $217 million represents the excess of the fair value of the net assets acquired compared with the total purchase consideration.

In connection with the acquisition the Company assumed certain product transportation and processing commitments (note 17).

As at December 31, 2020, 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.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. For the year ended December 31, 2020, pre-tax interest of $24 million (December 31, 2019 – $53 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.5% (December 31, 2019 – 4.0%).

6. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2019	$ 1,166	$ 317	$ 182	$ 124	$ 1,789
Additions [1]	**17**	**121**	**7**	**3**	**148**
Depreciation	**(124)**	**(53)**	**(51)**	**(26)**	**(254)**
Derecognitions	**(20)**	**(5)**	**(10)**	**—**	**(35)**
Foreign exchange adjustments and other	**(1)**	**(1)**	**—**	**(1)**	**(3)**
At December 31, 2020	**$ 1,038**	**$ 379**	**$ 128**	**$ 100**	**$ 1,645**

(1) The acquisition of Painted Pony in the fourth quarter of 2020 included lease assets of $93 million (note 5).

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, 2020 were as follows:

	Dec 31 2020	Dec 31 2019
Lease liabilities	**$ 1,690**	$ 1,809
Less: current portion	**189**	233
	$ 1,501	$ 1,576

Total cash outflows for leases for the three months ended December 31, 2020, including payments related to short-term leases not reported as lease assets, were $221 million (three months ended December 31, 2019 – $299 million; year ended December 31, 2020 – $983 million; year ended December 31, 2019 – $1,178 million). Interest expense on leases for the three months ended December 31, 2020 was $17 million (three months ended December 31, 2019 – $18 million; year ended December 31, 2020 – $67 million; year ended December 31, 2019 – $70 million).

7. INVESTMENTS

As at December 31, 2020, the Company had the following investments:

		Dec 31 2020		Dec 31 2019
Investment in PrairieSky Royalty Ltd.	**$**	**228**	$	345
Investment in Inter Pipeline Ltd.		**77**		145
	$	**305**	$	490

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

	Three Months Ended				Year Ended			
		Dec 31 2020		Dec 31 2019		**Dec 31 2020**		Dec 31 2019
Fair value (gain) loss from investments	**$**	**(33)**	$	77	**$**	**185**	$	34
Dividend income from investments		**(2)**		(7)		**(14)**		(28)
	$	**(35)**	$	70	**$**	**171**	$	6

The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") do not constitute significant influence, and are accounted for at fair value through profit or loss, measured at each reporting date. As at December 31, 2020, the Company's investments in PrairieSky and Inter Pipeline were classified as current assets.

The Company's investment in PrairieSky consists of 22.6 million common shares. As at December 31, 2020 the market price per common share was $10.09 (December 31, 2019 – $15.23).

The Company's investment in Inter Pipeline consists of 6.4 million common shares. As at December 31, 2020 the market price per common share was $11.87 (December 31, 2019 – $22.54).

On February 22, 2021, Brookfield Infrastructure Partners L.P. commenced a formal offer to purchase all issued and outstanding Inter Pipeline common shares for $16.50 per common share. The offer is open for acceptance until Monday, June 7, 2021.

8. OTHER LONG-TERM ASSETS

		Dec 31 2020		Dec 31 2019
North West Redwater Partnership	**$**	**555**	$	652
Prepaid cost of service tolls		**162**		130
Risk management (note 16)		**136**		290
Long-term inventory		**121**		121
Other (1)		**190**		84
		1,164		1,277
Less: current portion		**82**		54
	$	**1,082**	$	1,223

(1) The acquisition of Painted Pony in the fourth quarter of 2020 included physical product sales contracts valued at $111 million (note 5).

The Company has a 50% equity investment in and as at December 31, 2020 has made subordinated debt advances, net of repayments, of $555 million to NWRP, including accrued interest. The subordinated debt is repayable over 10 years commencing July 2021, and bears interest at prime plus 6%. During the year ended December 31, 2020, $124 million of the subordinated debt was repaid to the Company. NWRP operates a 50,000 barrels per day bitumen upgrader and refinery that targets to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission, an agent of the Government of Alberta, under a 30-year fee-for-service tolling agreement.

On June 1, 2020, the refinery achieved the Commercial Operation Date ("COD"), pursuant to the terms of the tolling agreement. The Company is unconditionally obligated to pay its 25% pro rata share of the debt tolls over the 30-year tolling period (note 17). Subsequent to COD, sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment.

The unrecognized share of the equity (income) loss from NWRP for the three months ended December 31, 2020 was a recovery of unrecognized equity losses of $6 million (year ended December 31, 2020 – unrecognized equity loss of $94 million; December 31, 2019 – recognized equity loss of $287 million and unrecognized equity loss of $59 million). As at December 31, 2020, the cumulative unrecognized share of equity losses from NWRP was $153 million (December 31, 2019 – $59 million).

9. LONG-TERM DEBT

	Dec 31 2020	Dec 31 2019
Canadian dollar denominated debt, unsecured		
Bank credit facilities	$ 1,614	$ 1,688
Medium-term notes	3,200	4,300
	4,814	5,988
US dollar denominated debt, unsecured		
Bank credit facilities (December 31, 2020 – US$3,953 million; December 31, 2019 – US$3,745 million)	5,041	4,855
Commercial paper (December 31, 2020 – US$426 million; December 31,2019 – US$254 million)	544	329
US dollar debt securities (December 31, 2020 – US$8,750 million; December 31, 2019 – US$7,650 million)	11,161	9,918
	16,746	15,102
Long-term debt before transaction costs and original issue discounts, net	21,560	21,090
Less: original issue discounts, net (1)	18	17
transaction costs (1) (2)	89	91
	21,453	20,982
Less: current portion of commercial paper	544	329
current portion of other long-term debt (1) (2)	799	2,062
	$ 20,110	$ 18,591

(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.

For the year ended December 31, 2020, the Company reported an unrealized foreign exchange gain of $267 million (December 31, 2019 – unrealized gain of $662 million) on its US dollar denominated debt.

Bank Credit Facilities and Commercial Paper

As at December 31, 2020, the Company had undrawn revolving bank credit facilities of $4,958 million. Additionally, the Company had in place fully drawn term credit facilities of $6,738 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit. At December 31, 2020, the Company had $544 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

- a $100 million demand credit facility;
- a $1,000 million non-revolving term credit facility maturing February 2022;
- a $2,425 million revolving syndicated credit facility maturing June 2022;
- a $3,088 million non-revolving term credit facility maturing June 2022;
- a $2,650 million non-revolving term credit facility maturing February 2023;
- a $2,425 million revolving syndicated credit facility maturing June 2023; and
- a £5 million demand credit facility related to the Company’s North Sea operations.

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

During the second quarter of 2020, the $750 million non-revolving term credit facility, originally due February 2021, was extended to February 2022 and increased to $1,000 million. Subsequent to December 31, 2020, the facility was extended to February 2023.

During 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. During the second quarter of 2020, the Company repaid $162.5 million related to the required annual amortization, reducing the facility balance to $3,088 million. Subsequent to December 31, 2020, the Company repaid a further $362.5 million on the facility, reducing the outstanding balance to $2,725 million, and satisfying the required annual amortization of $162.5 million originally due in June 2021. The facility matures in June 2022.

The revolving syndicated credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.

The Company’s borrowings under its US commercial paper program are authorized up to a maximum 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, 2020 was 1.1% (December 31, 2019 – 2.5%), and on total long-term debt outstanding for the year ended December 31, 2020 was 3.5% (December 31, 2019 – 4.0%).

As at December 31, 2020, letters of credit and guarantees aggregating to $489 million were outstanding.

Medium-Term Notes

During the fourth quarter of 2020, the Company issued $500 million of 1.45% medium-term notes due November 2023 and $300 million of 2.50% medium-term notes due January 2028.

After issuing these securities, the Company had $2,200 million remaining on its 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 2021. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

During the third quarter of 2020, the Company repaid $1,000 million of 2.89% medium-term notes. During the second quarter of 2020, the Company repaid $900 million of 2.05% medium-term notes.

US Dollar Debt Securities

During the second quarter of 2020, the Company issued US$600 million of 2.05% notes due July 2025 and US$500 million of 2.95% notes due July 2030.

After issuing these securities, the Company had US$1,900 million remaining on its 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 2021. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

10. OTHER LONG-TERM LIABILITIES

	Dec 31 2020	Dec 31 2019
Asset retirement obligations	**$ 5,861**	$ 5,771
Lease liabilities (note 6) (1)	**1,690**	1,809
Share-based compensation	**160**	297
Risk management (note 16)	**160**	112
Deferred purchase consideration (2)	**72**	95
Other (3)	**343**	98
	8,286	8,182
Less: current portion	**722**	819
	$ 7,564	$ 7,363

(1) The acquisition of Painted Pony in the fourth quarter of 2020 included lease liabilities of $93 million (note 5).

(2) Relates to the acquisition of the Joslyn oil sands project in 2018, payable in annual installments of $25 million over the next three years.

(3) The acquisition of Painted Pony in the fourth quarter of 2020 included product transportation and processing obligations valued at $268 million (note 5).

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 3.7% (December 31, 2019 – 3.8%) and inflation rates of up to 2% (December 31, 2019 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Dec 31 2020	Dec 31 2019
Balance – beginning of year	**$ 5,771**	$ 3,886
Liabilities incurred	**5**	15
Liabilities acquired, net	**13**	198
Liabilities settled	**(249)**	(296)
Asset retirement obligation accretion	**205**	190
Revision of cost and timing estimates	**(134)**	412
Change in discount rates	**253**	1,412
Foreign exchange adjustments	**(3)**	(46)
Balance – end of year	**5,861**	5,771
Less: current portion	**184**	208
	$ 5,677	$ 5,563

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 2020	Dec 31 2019
Balance – beginning of year	**$ 297**	$ 124
Share-based compensation (recovery) expense	**(82)**	223
Cash payment for stock options surrendered and PSUs vested	**(39)**	(2)
Transferred to common shares	**(21)**	(53)
Charged to Oil Sands Mining and Upgrading, net	**5**	5
Balance – end of year	**160**	297
Less: current portion	**119**	227
	$ 41	$ 70

Included within share-based compensation liability as at December 31, 2020 was $49 million related to PSUs granted to certain executive employees (December 31, 2019 – $62 million).

11. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Year Ended	
Expense (recovery)	**Dec 31 2020**	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Current corporate income tax – North America	**$ 42**	$ (20)	**$ (245)**	$ 354
Current corporate income tax – North Sea	**—**	40	**(4)**	112
Current corporate income tax – Offshore Africa	**5**	7	**17**	44
Current PRT [1] – North Sea	**(14)**	—	**(31)**	(89)
Other taxes	**2**	4	**6**	13
Current income tax	**35**	31	**(257)**	434
Deferred corporate income tax	**(25)**	194	**(181)**	(895)
Deferred PRT [1] – North Sea	**—**	—	**—**	1
Deferred income tax	**(25)**	194	**(181)**	(894)
Income tax	**$ 10**	$ 225	**$ (438)**	$ (460)

(1) Petroleum Revenue Tax

In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. In the fourth quarter of 2020, the Government of Alberta substantively enacted legislation to accelerate this reduction, lowering the corporate tax rate from 10% to 8%, effective July 1, 2020. This acceleration did not have a significant impact on the Company's deferred corporate income tax liability at December 31, 2020.

12. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Year Ended Dec 31, 2020		
Issued common shares	**Number of shares** (thousands)		**Amount**
Balance – beginning of year	**1,186,857**	**$**	**9,533**
Issued upon exercise of stock options	**3,979**		**108**
Previously recognized liability on stock options exercised for common shares	**—**		**21**
Purchase of common shares under Normal Course Issuer Bid	**(6,970)**		**(56)**
Balance – end of year	**1,183,866**	**$**	**9,606**

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 3, 2021, the Board of Directors declared a quarterly dividend of $0.47 per common share, an increase from the previous quarterly dividend of $0.425 per common share. The dividend is payable on April 5, 2021.

Normal Course Issuer Bid

On May 21, 2019, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company did not renew its Normal Course Issuer Bid after its expiry in May 2020.

During the first quarter of 2020, the Company purchased 6,970,000 common shares at a weighted average price of $38.84 per common share for a total cost of $271 million. Retained earnings were reduced by $215 million, representing the excess of the purchase price of common shares over their average carrying value.

On March 3, 2021, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the Toronto Stock Exchange ("TSX") to purchase, by way of a normal course issuer bid, up to 5.0% of its issued and outstanding common shares for the purpose of repurchasing a number of common shares approximately equal to the number of options exercised throughout the year in order to eliminate dilution for shareholders. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through the facilities of the TSX, alternative Canadian trading platforms and the New York Stock Exchange.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding at December 31, 2020:

	Year Ended Dec 31, 2020		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of year	**47,646**	**$**	**38.04**
Granted	**12,032**	**$**	**32.89**
Exercised for common shares	**(3,979)**	**$**	**27.24**
Surrendered for cash settlement	**(757)**	**$**	**29.34**
Forfeited	**(6,286)**	**$**	**39.65**
Outstanding – end of year	**48,656**	**$**	**37.53**
Exercisable – end of year	**17,970**	**$**	**39.59**

The 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.

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Dec 31 2020	Dec 31 2019
Derivative financial instruments designated as cash flow hedges	**$ 69**	$ 71
Foreign currency translation adjustment	**(61)**	(37)
	$ 8	$ 34

14. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2020, the ratio was within the target range at 39.6%.

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 2020	Dec 31 2019
Long-term debt, net (1)	**$ 21,269**	$ 20,843
Total shareholders' equity	**$ 32,380**	$ 34,991
Debt to book capitalization	**39.6%**	37.3%

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

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. At December 31, 2020, the Company was in compliance with this covenant.

15. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2020	Dec 31 2019	Dec 31 2020	Dec 31 2019
Weighted average common shares outstanding – basic (thousands of shares)	**1,181,968**	1,184,428	**1,181,768**	1,190,977
Effect of dilutive stock options (thousands of shares)	**924**	2,188	**—**	2,129
Weighted average common shares outstanding – diluted (thousands of shares)	**1,182,892**	1,186,616	**1,181,768**	1,193,106
Net earnings (loss)	**$ 749**	$ 597	**$ (435)**	$ 5,416
Net earnings (loss) per common share – basic	**$ 0.63**	$ 0.50	**$ (0.37)**	$ 4.55
– diluted	**$ 0.63**	$ 0.50	**$ (0.37)**	$ 4.54

16. FINANCIAL INSTRUMENTS

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

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

	Dec 31, 2019				
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 2,465	$ —	$ —	$ —	$ 2,465
Investments	—	490	—	—	490
Other long-term assets	652	—	290	—	942
Accounts payable	—	—	—	(816)	(816)
Accrued liabilities	—	—	—	(2,611)	(2,611)
Other long-term liabilities (1)	—	(21)	(91)	(1,904)	(2,016)
Long-term debt (2)	—	—	—	(20,982)	(20,982)
	$ 3,117	$ 469	$ 199	$ (26,313)	$ (22,528)

(1) Includes $1,690 million of lease liabilities (December 31, 2019 – $1,809 million) and $72 million of deferred purchase consideration payable over the next three years (December 31, 2019 – $95 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, 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)**	**$ —**	**$ —**

	Dec 31, 2019							
	Carrying amount		Fair value					
Asset (liability) [1] [2]			Level 1		Level 2		Level 3 [4] [5]	
Investments [3]	$	490	$	490	$	—	$	—
Other long-term assets	$	942	$	—	$	290	$	652
Other long-term liabilities	$	(207)	$	—	$	(112)	$	(95)
Fixed rate long-term debt [6] [7]	$	(14,110)	$	(15,938)	$	—	$	—

(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 is 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 2020**		Dec 31 2019
Derivatives held for trading				
Natural gas fixed price swaps	**$**	**(5)**	$	(3)
Natural gas basis swaps		**(40)**		(8)
Foreign currency forward contracts		**(7)**		(10)
Cash flow hedges				
Foreign currency forward contracts		**(108)**		(91)
Cross currency swaps		**136**		290
	$	**(24)**	$	178
Included within:				
Current portion of other long-term assets	**$**	**5**	$	8
Current portion of other long-term liabilities		**(131)**		(112)
Other long-term assets		**131**		282
Other long-term liabilities		**(29)**		—
	$	**(24)**	$	178

For the year ended December 31, 2020, the ineffectiveness arising from cash flow hedges was a loss of $1 million (year ended December 31, 2019 – gain of $3 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 2020**	Dec 31 2019
Balance – beginning of year	**$ 178**	$ 356
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities [1]	**(32)**	(13)
Foreign exchange	**(168)**	(231)
Other comprehensive income	**(2)**	66
Balance – end of year	**(24)**	178
Less: current portion	**(126)**	(104)
	$ 102	$ 282

(1) Includes the fair value movement in commodity financial instruments acquired from Painted Pony from the date of acquisition (note 5).

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

	Three Months Ended		Year Ended	
	Dec 31 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Net realized risk management loss	**$ 23**	$ 11	**$ 32**	$ 64
Net unrealized risk management (gain) loss	**(21)**	17	**(39)**	13
	$ 2	$ 28	**$ (7)**	$ 77

Financial Risk Factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases.

At December 31, 2020, the Company had the following derivative financial instruments outstanding. All of these instruments were assumed in the acquisition of Painted Pony in the fourth quarter of 2020:

	Remaining term		Weighted average volume	Weighted average price	Index
Natural Gas					
Fixed price swap	Jan 2021 -	Dec 2021	37,337 GJ/d	$2.03/GJ	AECO
	Jan 2021 -	Dec 2021	31,178 MMBtu/d	US$2.46/MMBtu	DAWN
	Jan 2021 -	Dec 2021	20,808 MMBtu/d	US$2.54/MMBtu	NYMEX
	Jan 2021 -	Dec 2021	17,466 MMBtu/d	US$2.70/MMBtu	SUMAS
Differential swap	Jan 2021 -	Aug 2021	20,000 GJ/d	$0.29/GJ	AECO-STN 2
Basis swap	Jan 2021 -	Dec 2023	53,333 MMBtu/d	US$1.23/MMBtu	AECO
	Jan 2024 -	Dec 2025	20,000 MMBtu/d	US$0.97/MMBtu	AECO
	Jan 2021 -	Dec 2021	20,000 MMBtu/d	US$0.09/MMBtu	DAWN

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2020, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

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

At December 31, 2020, 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 2021	–	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, 2020 and was classified as a cash flow hedge.

In addition to the cross currency swap contract noted above, at December 31, 2020, the Company had US$4,951 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$4,379 million designated as cash flow hedges.

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.

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, 2020, 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, 2020, the Company had net risk management assets of $129 million with specific counterparties related to derivative financial instruments (December 31, 2019 – $265 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.

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	$ 667	$ —	$ —	$ —
Accrued liabilities	$ 2,346	$ —	$ —	$ —
Long-term debt (1)	$ 1,343	$ 4,887	$ 7,051	$ 8,279
Other long-term liabilities (2)	$ 345	$ 200	$ 435	$ 942
Interest and other financing expense (3)	$ 776	$ 693	$ 1,619	$ 4,452

(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, $189 million; one to less than two years, $162 million; two to less than five years, $397 million; and thereafter, $942 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, 2020.

17. 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, 2020:

	2021	2022	2023	2024	2025	Thereafter
Product transportation and processing (1) (2)	$ 870	$ 817	$ 858	$ 841	$ 809	$ 10,370
North West Redwater Partnership service toll (3)	$ 163	$ 160	$ 160	$ 156	$ 150	$ 2,694
Offshore vessels and equipment	$ 64	$ 9	$ —	$ —	$ —	$ —
Field equipment and power	$ 28	$ 21	$ 21	$ 21	$ 21	$ 246
Other	$ 25	$ 21	$ 21	$ 22	$ 22	$ 16

(1) Includes commitments pertaining to a 20-year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals.

(2) The acquisition of Painted Pony in the fourth quarter of 2020 included approximately $2,400 million of product transportation and processing commitments (note 5).

(3) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt component of the monthly cost of service tolls. Included in the cost of service tolls is $1,169 million of interest payable over the 30-year tolling period (note 8).

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.

18. 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	
	2020	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Segmented product sales																
Crude oil and NGLs	**2,374**	2,882	**7,480**	9,679	**104**	297	**417**	860	**90**	94	**318**	632	**2,568**	3,273	**8,215**	11,171
Natural gas	**434**	327	**1,242**	1,150	**1**	12	**12**	57	**10**	15	**42**	67	**445**	354	**1,296**	1,274
Other income and revenue [1]	**13**	—	**41**	6	**—**	2	**3**	5	**(4)**	2	**18**	8	**9**	4	**62**	19
Total segmented product sales	**2,821**	3,209	**8,763**	10,835	**105**	311	**432**	922	**96**	111	**378**	707	**3,022**	3,631	**9,573**	12,464
Less: royalties	**(173)**	(308)	**(503)**	(998)	**—**	(1)	**(1)**	(2)	**(5)**	(7)	**(16)**	(42)	**(178)**	(316)	**(520)**	(1,042)
Segmented revenue	**2,648**	2,901	**8,260**	9,837	**105**	310	**431**	920	**91**	104	**362**	665	**2,844**	3,315	**9,053**	11,422
Segmented expenses																
Production	**633**	628	**2,510**	2,425	**99**	121	**321**	391	**27**	30	**103**	109	**759**	779	**2,934**	2,925
Transportation, blending and feedstock [2]	**1,026**	1,042	**3,393**	2,935	**2**	4	**15**	19	**—**	1	**1**	2	**1,028**	1,047	**3,409**	2,956
Depletion, depreciation and amortization	**1,017**	935	**3,780**	3,326	**61**	98	**277**	308	**54**	50	**190**	242	**1,132**	1,083	**4,247**	3,876
Asset retirement obligation accretion	**24**	27	**97**	95	**8**	7	**30**	28	**1**	2	**6**	6	**33**	36	**133**	129
Risk management activities (commodity derivatives)	**(29)**	13	**(20)**	49	**—**	—	**—**	—	**—**	—	**—**	—	**(29)**	13	**(20)**	49
Gain on acquisition	**(217)**	—	**(217)**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(217)**	—	**(217)**	—
Equity loss from investments	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**2,454**	2,645	**9,543**	8,830	**170**	230	**643**	746	**82**	83	**300**	359	**2,706**	2,958	**10,486**	9,935
Segmented earnings (loss) before the following	**194**	256	**(1,283)**	1,007	**(65)**	80	**(212)**	174	**9**	21	**62**	306	**138**	357	**(1,433)**	1,487
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 expense (recovery)																
Deferred income tax (recovery) expense																
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	
	2020	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Segmented product sales																
Crude oil and NGLs [3]	**2,078**	2,633	**7,389**	11,340	**21**	26	**83**	88	**(75)**	15	**(108)**	351	**4,592**	5,947	**15,579**	22,950
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**51**	28	**182**	145	**496**	382	**1,478**	1,419
Other income and revenue [1]	**14**	2	**139**	6	**99**	—	**202**	—	**9**	—	**31**	—	**131**	6	**434**	25
Total segmented product sales	**2,092**	2,635	**7,528**	11,346	**120**	26	**285**	88	**(15)**	43	**105**	496	**5,219**	6,335	**17,491**	24,394
Less: royalties	**(23)**	(118)	**(78)**	(481)	**—**	—	**—**	—	**—**	—	**—**	—	**(201)**	(434)	**(598)**	(1,523)
Segmented revenue	**2,069**	2,517	**7,450**	10,865	**120**	26	**285**	88	**(15)**	43	**105**	496	**5,018**	5,901	**16,893**	22,871
Segmented expenses																
Production	**787**	856	**3,114**	3,276	**75**	5	**184**	20	**10**	8	**48**	56	**1,631**	1,648	**6,280**	6,277
Transportation, blending and feedstock [2][3]	**240**	330	**881**	1,306	**83**	—	**181**	—	**(33)**	39	**27**	437	**1,318**	1,416	**4,498**	4,699
Depletion, depreciation and amortization	**479**	464	**1,784**	1,656	**4**	3	**15**	14	**—**	—	**—**	—	**1,615**	1,550	**6,046**	5,546
Asset retirement obligation accretion	**18**	14	**72**	61	**—**	—	**—**	—	**—**	—	**—**	—	**51**	50	**205**	190
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(29)**	13	**(20)**	49
Gain on acquisition	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(217)**	—	**(217)**	—
Equity loss from investments	**—**	—	**—**	—	**—**	73	**—**	287	**—**	—	**—**	—	**—**	73	**—**	287
Total segmented expenses	**1,524**	1,664	**5,851**	6,299	**162**	81	**380**	321	**(23)**	47	**75**	493	**4,369**	4,750	**16,792**	17,048
Segmented earnings (loss) before the following	**545**	853	**1,599**	4,566	**(42)**	(55)	**(95)**	(233)	**8**	(4)	**30**	3	**649**	1,151	**101**	5,823
Non–segmented expenses																
Administration													**107**	95	**391**	344
Share-based compensation													**123**	161	**(82)**	223
Interest and other financing expense													**177**	217	**756**	836
Risk management activities (other)													**31**	15	**13**	28
Foreign exchange gain													**(513)**	(229)	**(275)**	(570)
(Gain) loss from investments													**(35)**	70	**171**	6
Total non-segmented expenses													**(110)**	329	**974**	867
Earnings (loss) before taxes													**759**	822	**(873)**	4,956
Current income tax expense (recovery)													**35**	31	**(257)**	434
Deferred income tax (recovery) expense													**(25)**	194	**(181)**	(894)
Net earnings (loss)													**749**	597	**(435)**	5,416

(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 a provision of $143 million relating to the Keystone XL pipeline project in the fourth quarter of 2020 in the North America segment.
(3) 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, 2020			Dec 31, 2019		
	Net expenditures (proceeds)	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ (7)**	**$ (150)**	**$ (157)**	$ 129	$ (219)	$ (90)
Offshore Africa	**12**	**3**	**15**	35	(2)	33
	$ 5	**$ (147)**	**$ (142)**	$ 164	$ (221)	$ (57)
Property, plant and equipment						
Exploration and Production						
North America [3] [4]	**$ 999**	**$ 371**	**$ 1,370**	$ 4,702	$ 918	$ 5,620
North Sea	**122**	**(21)**	**101**	196	153	349
Offshore Africa [5]	**87**	**7**	**94**	194	(1,476)	(1,282)
	1,208	**357**	**1,565**	5,092	(405)	4,687
Oil Sands Mining and Upgrading [6]	**1,323**	**(629)**	**694**	1,525	344	1,869
Midstream and Refining	**5**	**1**	**6**	10	—	10
Head office	**19**	**—**	**19**	34	(3)	31
	$ 2,555	**$ (271)**	**$ 2,284**	$ 6,661	$ (64)	$ 6,597

(1) This table provides a reconciliation of capitalized costs, reported in note 4 and note 5, 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 $91 million for exploration and evaluation assets and $3,126 million for property, plant and equipment acquired from Devon in the second quarter of 2019.

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

(5) Includes a derecognition of property, plant and equipment of $1,515 million following the FPSO demobilization at the Olowi field, Gabon in the first quarter of 2019.

(6) Net expenditures include capitalized interest and share-based compensation.

Segmented Assets

	Dec 31 2020	Dec 31 2019
Exploration and Production		
North America	**$ 29,094**	$ 30,963
North Sea	**1,624**	1,948
Offshore Africa	**1,407**	1,529
Other	**81**	30
Oil Sands Mining and Upgrading	**41,567**	42,006
Midstream and Refining	**1,301**	1,418
Head office	**202**	227
	$ 75,276	$ 78,121

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 2019. 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, 2020:	
Interest coverage (times)	
Net earnings (1) (2)	(0.1x)
Adjusted funds flow (3)	7.3x

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

(2) Additional earnings of $897 million would be required to achieve a net earnings interest coverage ratio of 1.0x.

(3) 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

Board of Directors

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M. Elizabeth Cannon, O.C.

N. Murray Edwards, O.C.

Christopher L. Fong

Ambassador Gordon D. Giffin

Wilfred A. Gobert

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Chief Operating Officer, Exploration and Production

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Senior Vice-President, Marketing

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Senior Vice-President, Thermal

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Senior Vice-President, Production

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Senior Vice-President, Safety, Risk Management & Innovation

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Vice-President, Legal, General Counsel and Corporate Secretary

Betty Yee
Vice-President, Land

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

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Investor Relations

Telephone: (403) 514-7777
Email: ir@cnrl.com

CANADIAN NATURAL RESOURCES LIMITED
2100, 855 - 2nd Street S.W., Calgary, Alberta T2P 4J8
Telephone: (403) 517-6700 Facsimile: (403) 517-7350
Website: www.cnrl.com
Printed in Canada