Canadian Natural

FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2021 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2021 FIRST QUARTER RESULTS

Commenting on the Company's first quarter 2021 results, Tim McKay, President of Canadian Natural stated "The COVID-19 pandemic continues to challenge our everyday living and the way we operate our businesses. With our strong measures in place we have minimized impacts on our operations, but it remains a daily challenge for our field staff to do it safe and do it right. As the global vaccine distribution increases and crude oil demand recovers, especially in the United States, we are seeing improved commodity pricing, and when combined with our top tier execution and disciplined capital program we are well positioned to generate significant free cash flow in 2021.

Our first quarter results were strong as we achieved record quarterly production of approximately 1,246 MBOE/d and record quarterly liquids production of over 979,000 bbl/d, as a result of our effective and efficient operations and high operating levels. As our large and diverse asset base realized strong netbacks, we drove significant adjusted funds flow in the quarter of over $2.7 billion.

In Q1/21 our Oil Sands Mining and Upgrading segment continued to achieve strong operating results with record quarterly production of approximately 468,800 bbl/d of high value Synthetic Crude Oil ("SCO") and industry leading operating costs of $19.82/bbl (US$15.66/bbl), a decrease of 5% from Q1/20 levels, despite increased energy costs."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "Canadian Natural is in a strong financial position. Our robust business model delivered strong financial results with net earnings of approximately $1.4 billion and adjusted net earnings of over $1.2 billion in the first quarter.

Our top tier operating results generated strong quarterly free cash flow of approximately $1.4 billion after capital expenditures and dividends. Accordingly our balance sheet strengthened significantly in Q1/21, as we were able to reduce our net long-term debt by approximately $1.4 billion in Q1/21. Our first quarter debt reduction included the permanent repayment and cancellation of term debt totaling approximately $1.0 billion. Subsequent to quarter end we permanently repaid and cancelled approximately $0.7 billion of additional term debt.

Annual 2021 WTI strip pricing has strengthened and using approximately US$60/bbl our targeted free cash flow increases significantly to $5.7 billion to $6.2 billion, after our budgeted capital program of approximately $3.2 billion and dividends of approximately $2.2 billion. As a result our balance sheet is targeted to further strengthen throughout 2021, with debt to adjusted EBITDA targeted to improve to approximately 1.1x and debt to book capitalization targeted to improve to approximately 29%, at the mid-point of our targeted free cash flow range."

QUARTERLY HIGHLIGHTS

	Three Months Ended		
($ millions, except per common share amounts)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Net earnings (loss)	**$ 1,377**	$ 749	$ (1,282)
Per common share – basic	**$ 1.16**	$ 0.63	$ (1.08)
– diluted	**$ 1.16**	$ 0.63	$ (1.08)
Adjusted net earnings (loss) from operations (1)	**$ 1,219**	$ 176	$ (295)
Per common share – basic	**$ 1.03**	$ 0.15	$ (0.25)
– diluted	**$ 1.03**	$ 0.15	$ (0.25)
Cash flows from operating activities	**$ 2,536**	$ 1,270	$ 1,725
Adjusted funds flow (2)	**$ 2,712**	$ 1,708	$ 1,337
Per common share – basic	**$ 2.29**	$ 1.45	$ 1.13
– diluted	**$ 2.28**	$ 1.44	$ 1.13
Cash flows used in investing activities	**$ 648**	$ 624	$ 859
Net capital expenditures, excluding net acquisition costs (3)	**$ 808**	$ 655	$ 838
Net capital expenditures, including net acquisition costs (3)	**$ 808**	$ 1,176	$ 838
Daily production, before royalties			
Natural gas (MMcf/d)	**1,598**	1,644	1,440
Crude oil and NGLs (bbl/d)	**979,352**	927,190	938,676
Equivalent production (BOE/d) (4)	**1,245,703**	1,201,198	1,178,752

(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.

QUARTERLY HIGHLIGHTS

- Net earnings of $1,377 million and adjusted net earnings from operations of $1,219 million were realized in Q1/21.
  - Adjusted net earnings increased by $1,043 million from Q4/20 levels as a result of higher realized pricing and effective and efficient operations.
- Cash flows from operating activities were $2,536 million in Q1/21.
- The strength of the Company's assets supported by its safe, effective and efficient operations demonstrated its ability to generate significant and sustainable free cash flow over the long-term, making Canadian Natural's business unique, robust and sustainable.
  - As a result, Canadian Natural generated strong quarterly adjusted funds flow of $2,712 million in Q1/21, increases of $1,375 million and $1,004 million from Q1/20 and Q4/20 levels respectively, driven by higher realized pricing and effective and efficient operations.

- Canadian Natural generated robust quarterly free cash flow of $1,401 million in Q1/21, after net capital expenditures of $808 million and dividend payments of $503 million, reflecting the strength of the Company's effective and efficient operations and its high quality, long life low decline asset base.
  - The Company's 2021 budgeted capital expenditure 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.
- Canadian Natural demonstrated our focus on further strengthening our balance sheet with strong financial results in Q1/21, reducing net debt by approximately $1.4 billion from Q4/20 levels. Since Q2/20 net debt has decreased by approximately $2.9 billion.
  - In Q1/21 the Company repaid $962.5 million on its $3,088 million non-revolving term loan, more than satisfying the required annual amortization of $162.5 million due in June 2021. Subsequent to quarter end, an additional $650 million was repaid on this facility, reducing the outstanding balance to $1,475 million.
  - In Q1/21 the Company's $1,000 million non-revolving term credit facility, originally due February 2022, was extended to February 2023.
- In March 2021, the Company declared a quarterly dividend of $0.47 per share, an increase of 11% from the previous level of $0.425 per share, marking 2021 as the Company's 21st consecutive year of dividend increases, reflecting the Board of Directors' confidence in Canadian Natural's strength and the robustness of the Company's assets and its ability to generate significant and sustainable free cash flow.
  - Subsequent to quarter end the Company declared a quarterly dividend of $0.47 per share, payable on July 5, 2021.
- In March 2021, the Board of Directors authorized management to repurchase shares under a Normal Course Issuer Bid ("NCIB") to approximately offset options exercised throughout the coming year, in order to minimize or eliminate dilution to shareholders.
  - Share repurchases for cancellation in Q1/21 totaled 600,000 common shares at a weighted average price of $38.61.
  - Subsequent to quarter end, up to and including May 5, 2021, the Company executed on additional share repurchases for cancellation of 960,000 common shares at a weighted average share price of $38.15.
- Returns to shareholders have been significant as Canadian Natural has returned approximately $1.1 billion by way of dividends and share repurchases in 2021 up to and including May 5, 2021.
- In Q1/21 the Company achieved record quarterly production volumes of 1,245,703 BOE/d, increases of 6% and 4% from Q1/20 and Q4/20 levels respectively, with continued focus on safe, effective and efficient operations.
  - Record quarterly liquids production was achieved in Q1/21 averaging 979,352 bbl/d, increases of 4% and 6% from Q1/20 and Q4/20 levels respectively.
  - Corporate natural gas production averaged 1,598 MMcf/d in Q1/21, an increase of 11% from Q1/20 levels. The increase from Q1/20 was primarily as a result of acquired production in Q4/20, strong base production and volume additions, partially offset by natural field declines and the shutdown of our Pine River gas plant in February 2021.
    - Corporate natural gas operating costs in Q1/21 averaged $1.27/Mcf, a decrease of 3% from Q1/20 levels and an increase of 15% from Q4/20 levels. The increase from Q4/20 was primarily due to normal seasonality including an increase in electricity costs, partially offset by the impact of the continuous focus on operating costs.
- The Company's world class Oil Sands Mining and Upgrading assets achieved record quarterly production averaging 468,803 bbl/d of SCO in Q1/21, increases of 7% and 12% from Q1/20 and Q4/20 levels respectively. Record SCO production was primarily as a result of industry leading utilization and operational enhancements.
  - Operating costs from the Company's Oil Sands Mining and Upgrading assets are top tier, averaging $19.82/bbl (US$15.66/bbl) of SCO in Q1/21, decreases of 5% and 2% from Q1/20 and Q4/20 levels respectively. The reductions were primarily due to our focus on continuous improvement, effective and efficient operations and operational enhancements, offsetting the impact of higher energy costs, including natural gas, in Q1/21.
    - In Q1/21 the Company increased SCO sales from the Oil Sands Mining and Upgrading segment by over 41,000 bbl/d from Q1/20 levels while essentially maintaining absolute operating cost levels, excluding

natural gas costs, over the same period, demonstrating the continued focus on effective and efficient operations and the underlying value of high utilization relative to fixed costs.

- Subsequent to quarter end the planned turnaround at Horizon was successfully completed and SCO production is targeted to resume on May 8, 2021. Additionally, at the Athabasca Oil Sands Project ("AOSP") the Company targets to perform planned de-coking in May 2021. The Company's annual 2021 budgeted total production volume range remains unchanged.

▪ Canadian Natural's North America E&P liquids production, including thermal in situ, was strong in Q1/21 averaging 478,736 bbl/d, an increase of 5% from Q1/20 levels and comparable with Q4/20 levels.

  - North American E&P liquids, including thermal in situ operations, achieved operating costs of $12.80/bbl (US$10.11/bbl) in Q1/21, comparable with Q1/20 levels of $12.69/bbl and an increase of 18% from Q4/20 levels of $10.81/bbl. The increase in operating costs from Q4/20 levels was primarily due to higher energy costs with the remainder from normal seasonality costs.

▪ Canadian Natural's thermal in situ production was strong in Q1/21, averaging 267,530 bbl/d, an increase of 17% over Q1/20 levels and comparable with Q4/20 levels.

  - Strong operating costs from the Company's thermal in situ assets were achieved in Q1/21, averaging $11.40/bbl (US$9.01/bbl) an increase of 3% from Q1/20 levels. The increase in operating costs was primarily due to increases in energy costs, partially offset by cost reductions as a result of higher production volumes and effective and efficient operations.

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 81% of the Company's total liquids production in Q1/21, the majority of which is zero decline high value SCO production from the Company's world class Oil Sands Mining and Upgrading assets. The remaining balance of long life low decline production comes from Canadian Natural's top tier thermal in situ oil sands operations and the Company's Pelican Lake heavy crude oil assets. The combination of 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	Three Months Ended Mar 31			
	2021		2020	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**46**	**44**	37	35
Natural gas	**27**	**22**	12	11
Dry	**—**	**—**	—	—
Subtotal	**73**	**66**	49	46
Stratigraphic test / service wells	**395**	**328**	420	367
Total	**468**	**394**	469	413
Success rate (excluding stratigraphic test / service wells)		**100%**		100%

- The Company's total crude oil and natural gas drilling program of 66 net wells for the three months ended March 31, 2021, excluding stratigraphic/service wells, represents an increase of 20 net wells from the same period in 2020.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs production (bbl/d)	**211,206**	209,710	228,574
Net wells targeting crude oil	**39**	5	28
Net successful wells drilled	**39**	5	28
Success rate	**100%**	100%	100%

- Canadian Natural's North America E&P crude oil and NGL production volumes, excluding thermal in situ operations, averaged 211,206 bbl/d in Q1/21, a decrease of 8% from Q1/20 levels and comparable with Q4/20 levels. The decrease from Q1/20 was primarily due to natural field declines and deferred 2020 drilling activity.

- Primary heavy crude oil production averaged 62,695 bbl/d in Q1/21, decreases of 24% and 4% from Q1/20 and Q4/20 levels respectively, primarily due to natural field declines.
    - Operating costs in the Company's primary heavy crude oil operations averaged $18.89/bbl (US$14.92/bbl) in Q1/21, comparable with Q1/20 levels, strong results given the decrease in production volumes and increase in energy costs.
    - As a part of the 2021 budget, 13 net slant wells and 14 net horizontal multilateral wells were drilled in Q1/21 as planned.
        - The majority of these wells are in the early stages of ramping up or target to come on production in Q2/21 as budgeted. Early highlights from the Q1/21 drilling include 5 net Clearwater horizontal multilateral wells at Smith, that are now on-stream. Production from these wells has been strong totaling approximately 2,700 bbl/d, above budgeted rates by approximately 900 bbl/d, with low capital efficiencies of approximately $3,400 per flowing BOE.
- Pelican Lake production was strong in Q1/21 averaging 55,498 bbl/d, comparable with prior periods, demonstrating the strength of this long life low decline asset and the continued success of the Company's world class polymer flood.
    - The Company continues to focus on safe, effective and efficient operations, realizing strong operating costs in Q1/21 at Pelican Lake, averaging $7.38/bbl (US$5.83/bbl), an increase of 19% from Q1/20 primarily due to increases in energy costs.
- North American light crude oil and NGL production averaged 93,013 bbl/d in Q1/21, increases of 5% and 6% from Q1/20 and Q4/20 levels respectively. The increases are primarily as a result of strong results from drilling completed in Q4/20 and Q1/21.
    - Operating costs in the Company's North America light crude oil and NGL areas averaged $16.07/bbl (US$12.70/bbl) in Q1/21, comparable with Q1/20 levels, as a result of effective and efficient operations.
    - The Company continues to advance its high value Montney light crude oil development plan at Wembley, where 5 net wells have been drilled to date from the budgeted 18 net wells targeted to be on stream in 2021. Construction on the new crude oil battery is proceeding on time and on budget and is 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		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Bitumen production (bbl/d)	**267,530**	266,179	228,303
Net wells targeting bitumen	**3**	—	6
Net successful wells drilled	**3**	—	6
Success rate	**100%**	—	100%

- Canadian Natural's thermal in situ production was strong in Q1/21, averaging 267,530 bbl/d, an increase of 17% over Q1/20 levels and comparable with Q4/20 levels.
    - Strong operating costs for the Company's thermal in situ assets were achieved in Q1/21, averaging $11.40/bbl (US$9.01/bbl) an increase of 3% from Q1/20 levels. The increase in operating costs was primarily due to increases in energy costs, partially offset by cost reductions as a result of higher production volumes and effective and efficient operations.

- Solvent enhanced oil recovery technology targets to increase bitumen production, reduce Steam to Oil Ratio ("SOR"), reduce Green House Gas ("GHG") intensity and have high solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
  - At Kirby South, results from our on-going two year pilot of this technology indicate a significant SOR and GHG intensity reduction of approximately 45%, within the targeted range, can be achieved with the process. Monitoring of solvent recovery will continue for the remainder of 2021 to conclude the pilot results.
  - At Primrose, in the steam flood area, a solvent injection pilot is targeted to commence in Q4/21. This second pilot will consist of 9 wells (5 producers and 4 injectors) and similar to the first pilot at Kirby South, is targeted to operate for a two year period.

North America Natural Gas

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Natural gas production (MMcf/d)	**1,585**	1,623	1,407
Net wells targeting natural gas	**22**	9	11
Net successful wells drilled	**22**	9	11
Success rate	**100%**	100%	100%

- North America natural gas production was strong in Q1/21 averaging 1,585 MMcf/d, an increase of 13% from Q1/20 levels. The increase from Q1/20 was primarily as a result of acquired production in Q4/20, strong base production and volume additions, partially offset by natural field declines and the shutdown of our Pine River gas plant in February 2021.
  - North America natural gas operating costs in Q1/21 averaged $1.24/Mcf, comparable with Q1/20 levels and an increase of 16% from Q4/20 levels. The increase from Q4/20 was primarily due to normal seasonality including an increase in electricity costs, partially offset by the impact of the continuous focus on operating costs.
- As part of the 2021 budget, in the liquids rich Montney, the Company targets to utilize facility capacity through its drill to fill strategy adding low cost, high value liquids rich natural gas volumes.
  - At Septimus, production was strong in Q1/21, essentially at facility capacity of 150 MMcf/d and 9,000 bbl/d of liquids.
    - A 5 net well pad is being drilled at Septimus, with a targeted on stream date in June 2021 and low capital efficiency of approximately $5,000 per flowing BOE. These wells target to keep the capacity full for the remainder of 2021.
    - Operating costs at Septimus remained strong in Q1/21, averaging $0.28/Mcfe, a decrease of 7% from Q1/20 levels.
  - At Townsend, Q1/21 production was approximately 255 MMcf/d and 5,500 bbl/d of liquids, above 2021 budget by 17 MMcf/d and 340 bbl/d of liquids.
    - Completions on a 6 well pad at Townsend are progressing, with total targeted rates of approximately 44 MMcf/d, targeted to come on stream in June 2021 with a strong capital efficiency of approximately $4,200 per flowing BOE.
    - Townsend remains on target to exit 2021 at a production rate of approximately 340 MMcf/d.

International Exploration and Production

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil production (bbl/d)			
North Sea	**19,959**	17,057	27,755
Offshore Africa	**11,854**	17,155	15,943
Natural gas production (MMcf/d)			
North Sea	**4**	4	23
Offshore Africa	**9**	17	10
Net wells targeting crude oil	**2.0**	—	1.0
Net successful wells drilled	**2.0**	—	1.0
Success rate	**100%**	—	100%

- International E&P crude oil production volumes averaged 31,813 bbl/d in Q1/21, decreases of 27% and 7% from Q1/20 and Q4/20 levels respectively.
  - In Q2/21 and Q3/21 the Company is planning turnarounds at two platforms in the North Sea and at one field in Offshore Africa. Targeted production impacts were included in the Company's annual 2021 budgeted production volume range.
  - In the North Sea, crude oil production volumes averaged 19,959 bbl/d in Q1/21, a decrease of 28% from Q1/20 levels and an increase of 17% from Q4/20 levels. The decrease in production from Q1/20 was primarily a result of the permanent cessation of production from the Banff and Kyle fields and natural field declines. The increase in production from Q4/20 primarily reflects the impact of planned turnaround activity during Q4/20, partially offset by natural field declines.
    - Crude oil operating costs in the North Sea averaged $42.24/bbl (US$33.37/bbl) in Q1/21, an increase of 42% from Q1/20 levels primarily due to lower volumes on a relatively fixed cost base and higher energy costs. Targeted operating costs remain in line with 2020 annual levels.
  - Offshore Africa crude oil production volumes averaged 11,854 bbl/d in Q1/21, decreases of 26% and 31% from Q1/20 and Q4/20 levels respectively. The decreases were primarily due to a planned turnaround at Baobab and an unplanned outage at Espoir in Q1/21.
    - Offshore Africa crude oil operating costs averaged $16.57/bbl (US$13.09/bbl) in Q1/21, an increase of 39% from Q1/20 levels, primarily due to the timing of liftings from various fields that have different cost structures and lower volumes on a relatively fixed cost base. Targeted operating costs remain in line with 2020 annual levels.

North America Oil Sands Mining and Upgrading

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Synthetic crude oil production (bbl/d) (1) (2)	**468,803**	417,089	438,101

(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 achieved record quarterly production averaging 468,803 bbl/d of SCO in Q1/21, increases of 7% and 12% from Q1/20 and Q4/20 levels respectively. Record SCO production was primarily as a result of industry leading utilization and operational enhancements.
  - Operating costs from the Company's Oil Sands Mining and Upgrading assets are top tier, averaging $19.82/bbl (US$15.66/bbl) of SCO in Q1/21, decreases of 5% and 2% from Q1/20 and Q4/20 levels

respectively. The reductions were primarily due to our focus on continuous improvement, effective and efficient operations and operational enhancements, offsetting the impact of higher energy costs, including natural gas, in Q1/21.

- In Q1/21 the Company increased SCO sales from the Oil Sands Mining and Upgrading segment by over 41,000 bbl/d from Q1/20 levels while essentially maintaining absolute operating cost levels, excluding natural gas costs, over the same period, demonstrating the continued focus on effective and efficient operations and the underlying value of high utilization relative to fixed costs.

- Subsequent to quarter end the planned turnaround at Horizon was successfully completed and SCO production is targeted to resume on May 8, 2021. Additionally, at the Athabasca Oil Sands Project ("AOSP") the Company targets to perform planned de-coking in May 2021. The Company's annual 2021 budgeted total production volume range remains unchanged.

MARKETING

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs pricing			
WTI benchmark price (US$/bbl) (1)	**$ 57.80**	$ 42.67	$ 46.08
WCS heavy differential as a percentage of WTI (%) (2)	**21%**	22%	44%
SCO price (US$/bbl)	**$ 54.30**	$ 39.69	$ 43.39
Condensate benchmark pricing (US$/bbl)	**$ 57.99**	$ 42.54	$ 45.54
Average realized pricing before risk management (C$/bbl) (3)	**$ 52.68**	$ 40.56	$ 25.90
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 2.77**	$ 2.62	$ 2.03
Average realized pricing before risk management (C$/Mcf)	**$ 3.42**	$ 2.94	$ 2.22

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

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

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

- Crude oil prices continues to improve with WTI averaging US$57.80/bbl in Q1/21, an increase of 25% from Q1/20 levels. The increase in WTI from comparable periods primarily reflected increased demand as a result of the positive impact of the global roll out of COVID-19 vaccinations on economic activity, the continuation of agreements by OPEC+ to maintain production cuts implemented in 2020 and the strengthening of the global economy.
  - As at May 5, 2021 for crude oil, annual WTI pricing of US$62.50/bbl is currently 59% higher than 2020 levels and the annual WCS heavy oil differential has improved significantly from 2020, currently at approximately 21**%**, in line with average historical levels.
- Natural gas prices continue to improve with AECO averaging $2.77/GJ in Q1/21, an increase of 36% from Q1/20 levels. The increase in natural gas prices from the comparable period primarily reflected increased intra-provincial and export demand.
- Market egress is targeted to improve in the short- and mid-term as construction is progressing on the Trans Mountain Expansion ("TMX") and the Enbridge Line 3 replacement.
  - Enbridge Line 3 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 in early 2023, on which Canadian Natural has 94,000 bbl/d committed capacity.

- The North West Redwater ("NWR") Refinery with targeted processing capacity of approximately 80,000 bbl/d of diluted bitumen, which improves 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 record quarterly production of 1,245,703 BOE/d in Q1/21, with approximately 99% of total production located in G7 countries.
- Canadian Natural generated robust free cash flow of $1,401 million in Q1/21, after net capital expenditures of $808 million and dividend payments of $503 million in the quarter, reflecting the strength of the Company's effective and efficient operations and its high quality, long life low decline asset base.
  - Canadian Natural demonstrated our focus on further strengthening of the balance sheet with its strong financial results in Q1/21, reducing net debt by $1,426 million, from Q4/20 levels. Since Q2/20 levels net debt has been decreased by $2,944 million.
    - In Q1/21 the Company repaid $962.5 million on its $3,088 million non-revolving term loan, more than satisfying the required annual amortization of $162.5 million originally due in June 2021. Subsequent to quarter end, an additional $650 million was repaid on this facility, reducing the outstanding balance to $1,475 million.
    - In Q1/21 the Company's $1,000 million non-revolving term credit facility, originally due February 2022, was extended to February 2023.
    - As at March 31, 2021, the Company had undrawn revolving bank credit facilities of approximately $5.0 billion. Including cash and cash equivalents and short-term investments, the Company had significant liquidity of approximately $5.5 billion. At March 31, 2021, the Company had approximately $0.1 billion drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - In March 2021, the Company declared a quarterly dividend of $0.47 per share, an increase of 11% from the previous level of $0.425 per share, marking 2021 as the Company's 21st consecutive year of dividend increases, reflecting the Board of Directors' confidence in Canadian Natural's strength and the robustness of the Company's assets and its ability to generate significant and sustainable free cash flow.
    - Subsequent to quarter end the Company declared a quarterly dividend of $0.47 per share, payable on July 5, 2021.
  - In March 2021, the Board of Directors authorized management to repurchase shares under a NCIB to approximately offset options exercised throughout the coming year, in order to minimize or eliminate dilution to shareholders.
    - Share repurchases for cancellation in Q1/21 totaled 600,000 common shares at a weighted average price of $38.61.
    - Subsequent to quarter end, up to and including May 5, 2021, the Company executed on additional share repurchases for cancellation of 960,000 common shares at a weighted average share price of $38.15.
- Returns to shareholders have been significant as Canadian Natural has returned approximately $1.1 billion by way of dividends and share repurchases in 2021 up to and including May 5, 2021.
- The strength of the Company's assets supported by its safe effective and efficient operations demonstrated its ability to generate significant and sustainable free cash flow over the long-term, making Canadian Natural's business unique, robust and sustainable.
  - 2021 free cash flow is targeted to be robust at $5.7 billion to $6.2 billion using approximately US$60/bbl WTI, after budgeted capital expenditures and dividends.

- The Company's 2021 budgeted capital expenditure 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 1.1x respectively, at the mid-point of targeted free cash flow range.

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.

- The Government of Canada's announcement on April 19, 2021 of its 2021 budget recognized the important role of carbon capture, utilization and storage projects for the oil sands sector to continue contributing to Canada’s economic growth while working towards climate objectives. As a leader in Carbon, Capture, Utilization and Storage ("CCUS"), Canadian Natural sees many opportunities for industry to advance investments in CCUS projects. Details of the proposed government program are important and the Company looks forward to working together with government through the upcoming consultation period.
- Additionally on April 22, 2021, the Government of Canada announced new targets to reduce GHG emissions by 40% to 45% below 2005 levels by 2030.
  - Based on these new announcements and the upcoming Government of Canada consultation period, the Company plans to update its environmental targets later in 2021.

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. For 2020 results showed 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 levels of 87%.
- In 2020 the Company planted its one millionth tree at AOSP and its one and a half millionth tree at Horizon, reclaiming land and contributing to increased carbon capture.
- In 2020 the Company successfully achieved three of our stated four environmental targets for 2025 relating to GHG and methane emissions intensity reductions and reduced fresh water usage.
- The Company targets the release of its 2020 Stewardship Report to Stakeholders in Q3/21. In September 2020, Canadian Natural published its 2019 Stewardship Report to Stakeholders, which is available on the Company's website at www.cnrl.com/report-to-stakeholders.

ADVISORY

Special Note Regarding non-GAAP and Other 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 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. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

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

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 including the impact of government grant income under the provincial well-site rehabilitation programs, and the settlement of long-term debt assumed in acquisitions. The Company considers net capital expenditures a key measure in evaluating its performance, as it provides an understanding of the Company’s capital spending activities in comparison to the Company's annual capital budget. Net capital expenditures may not be comparable to similar measures presented by other companies.

Free cash flow is a non-GAAP 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.

Long-term debt, net and net debt are other financial measures that are calculated as net current and long-term debt less cash and cash equivalents.

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 and short term investments, 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 8 - Long-term Debt in the Company's consolidated financial statements.

The Company's 2021 targeted annual adjusted funds flow, free cash flow and net debt are based upon forecasted commodity prices of US$60.47 WTI/bbl, WCS discount of US$11.95/bbl, AECO price of C$2.74/GJ and FX of US$1.00 to C$1.26. Forecasted net debt reflects estimated timing of cash receipts and expenditures.

ADVISORY

Special Note Regarding Forward-Looking Statements

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

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

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of effects of the novel coronavirus ("COVID-19") pandemic and the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+") which may impact, among other things, demand and supply for and market prices of the Company’s products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil and natural gas and NGLs prices including due to actions of OPEC+ taken in response to COVID-19 or otherwise; fluctuations in currency and interest rates; assumptions on which the Company’s current targets are based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company’s defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company’s and its subsidiaries’ ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting or upgrading of the Company’s bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company’s bitumen products; availability and cost of financing; the Company’s and its subsidiaries’ success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities (including production curtailments mandated by the Government of Alberta); government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short, medium, and long term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company’s provision for taxes; 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 ended March 31, 2021 and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2020. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the three months ended March 31, 2021 and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

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

The following discussion and analysis refers primarily to the Company's financial results for the three months ended March 31, 2021 in relation to the first quarter of 2020 and the fourth 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, 2020, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Information on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated May 5, 2021.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Mar 31 2021**	Dec 31 2020	Mar 31 2020
Product sales [1]	**$ 7,019**	$ 5,219	$ 4,652
Crude oil and NGLs	**$ 6,288**	$ 4,592	$ 4,323
Natural gas	**$ 555**	$ 496	$ 337
Net earnings (loss)	**$ 1,377**	$ 749	$ (1,282)
Per common share – basic	**$ 1.16**	$ 0.63	$ (1.08)
– diluted	**$ 1.16**	$ 0.63	$ (1.08)
Adjusted net earnings (loss) from operations [2]	**$ 1,219**	$ 176	$ (295)
Per common share – basic	**$ 1.03**	$ 0.15	$ (0.25)
– diluted	**$ 1.03**	$ 0.15	$ (0.25)
Cash flows from operating activities	**$ 2,536**	$ 1,270	$ 1,725
Adjusted funds flow [3]	**$ 2,712**	$ 1,708	$ 1,337
Per common share – basic	**$ 2.29**	$ 1.45	$ 1.13
– diluted	**$ 2.28**	$ 1.44	$ 1.13
Cash flows used in investing activities	**$ 648**	$ 624	$ 859
Net capital expenditures [4]	**$ 808**	$ 1,176	$ 838

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

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

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

(4) Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, the repayment of NWRP subordinated debt advances, abandonment expenditures including the impact of government grant income under the provincial well-site rehabilitation programs, and the settlement of long-term debt assumed in acquisitions. The Company considers net capital expenditures a key measure in evaluating its performance, as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. 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 Mar 31 2021	Dec 31 2020	Mar 31 2020
Net earnings (loss)	$ 1,377	$ 749	$ (1,282)
Share-based compensation, net of tax (1)	126	117	(221)
Unrealized risk management loss (gain), net of tax (2)	15	(16)	(15)
Unrealized foreign exchange (gain) loss, net of tax (3)	(172)	(534)	1,121
Realized foreign exchange gain on settlement of cross currency swaps, net of tax (4)	—	—	(166)
Gain on acquisition, net of tax (5)	—	(217)	—
(Gain) loss from investments, net of tax (6)	(117)	(33)	268
Other, net of tax (7)	(10)	110	—
Adjusted net earnings (loss) from operations	$ 1,219	$ 176	$ (295)

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings (loss) 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 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 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).

(7) During the first quarter of 2021, other reflects the after-tax impact of government grant income under the provincial well-site rehabilitation programs and 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.

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

($ millions)	Three Months Ended Mar 31 2021	Dec 31 2020	Mar 31 2020
Cash flows from operating activities	$ 2,536	$ 1,270	$ 1,725
Net change in non-cash working capital	10	394	(595)
Abandonment expenditures (1)	67	52	89
Other (2)	99	(8)	118
Adjusted funds flow	$ 2,712	$ 1,708	$ 1,337

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

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

SUMMARY OF FINANCIAL HIGHLIGHTS

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

Net earnings for the first quarter of 2021 were $1,377 million compared with a net loss of $1,282 million for the first quarter of 2020 and net earnings of $749 million for the fourth quarter of 2020. Net earnings for the first quarter of 2021 included net after-tax income of $158 million compared with net after-tax expenses of $987 million for the first quarter of 2020 and net after-tax income of $573 million for the fourth quarter of 2020 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 (gain) loss from investments, government grant income under the provincial well-site rehabilitation programs, and a provision relating to the Keystone XL pipeline project. Excluding these items, adjusted net earnings from operations for the first quarter of 2021 were $1,219 million compared with an adjusted net loss from operations of $295 million for the first quarter of 2020 and adjusted net earnings from operations of $176 million for the fourth quarter of 2020.

The increase in net earnings and adjusted net earnings from operations for the first quarter of 2021 compared with the net earnings (loss) and adjusted net earnings (loss) from operations for the comparable periods primarily reflected:

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

The impacts of share-based compensation, risk management activities, fluctuations in foreign exchange rates, and the gain on acquisition 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 first quarter of 2021 were $2,536 million compared with $1,725 million for the first quarter of 2020 and $1,270 million for the fourth 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 adjusted net earnings (loss) from operations, as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the first quarter of 2021 was $2,712 million compared with $1,337 million for the first quarter of 2020 and $1,708 million for the fourth 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 excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to NWRP, and prepaid cost of service tolls.

Production Volumes

Total production of crude oil and NGLs before royalties for the first quarter of 2021 increased 4% to 979,352 bbl/d from 938,676 bbl/d for the first quarter of 2020 and increased 6% from 927,190 bbl/d for the fourth quarter of 2020. Total natural gas production before royalties for the first quarter of 2021 increased 11% to 1,598 MMcf/d from 1,440 MMcf/d for the first quarter of 2020 and was comparable with 1,644 MMcf/d for the fourth quarter of 2020. Total production before royalties for the first quarter of 2021 increased 6% to 1,245,703 BOE/d from 1,178,752 BOE/d for the first quarter of 2020 and increased 4% from 1,201,198 BOE/d for the fourth 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 primarily reflects prevailing benchmark pricing. In the Company's Exploration and Production segments, the first quarter of 2021 crude oil and NGLs sales price averaged $52.68 per bbl, an increase of 103% compared with $25.90 per bbl for the first quarter of 2020, and an increase of 30% from $40.56 per bbl for the fourth quarter of 2020. The natural gas price increased 54% to average $3.42 per Mcf for the first quarter of 2021 from $2.22 per Mcf for the first quarter of 2020, and increased 16% from $2.94 per Mcf for the fourth quarter of 2020. In the Oil Sands Mining and Upgrading segment, the Company's SCO sales price increased 27% to average $64.60 per bbl for the first quarter of 2021 from $50.88 per bbl from the first quarter of 2020, and increased 33% from $48.56 per bbl for the fourth 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, first quarter of 2021 crude oil and NGLs production expense averaged $14.56 per bbl, an increase of 6% from $13.71 for the first quarter of 2020, and an increase of 17% from $12.47 per bbl for the fourth quarter of 2020. Natural gas production expense averaged $1.27 per Mcf for the first quarter of 2021, a decrease of 3% from $1.31 per Mcf for the first quarter of 2020 and an increase of 15% from $1.10 per Mcf for the fourth quarter of 2020. In the Oil Sands Mining and Upgrading segment, production costs averaged $19.82 per bbl for the first quarter of 2021, a decrease of 5% from $20.76 per bbl for the first quarter of 2020, and a decrease of 2% from $20.20 per bbl for the fourth 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)		**Mar 31 2021**		Dec 31 2020		Sep 30 2020		Jun 30 2020
Product sales [1]	**$**	**7,019**	$	5,219	$	4,676	$	2,944
Crude oil and NGLs	**$**	**6,288**	$	4,592	$	4,202	$	2,462
Natural gas	**$**	**555**	$	496	$	338	$	307
Net earnings (loss)	**$**	**1,377**	$	749	$	408	$	(310)
Net earnings (loss) per common share								
– basic	**$**	**1.16**	$	0.63	$	0.35	$	(0.26)
– diluted	**$**	**1.16**	$	0.63	$	0.35	$	(0.26)
($ millions, except per common share amounts)		Mar 31 2020		Dec 31 2019		Sep 30 2019		Jun 30 2019
Product sales [1]	$	4,652	$	6,335	$	6,587	$	5,931
Crude oil and NGLs	$	4,323	$	5,947	$	6,324	$	5,597
Natural gas	$	337	$	382	$	257	$	324
Net earnings (loss)	$	(1,282)	$	597	$	1,027	$	2,831
Net earnings (loss) per common share								
– basic	$	(1.08)	$	0.50	$	0.87	$	2.37
– diluted	$	(1.08)	$	0.50	$	0.87	$	2.36

(1) Further details related to product sales for the three months ended March 31, 2021 and 2020 are disclosed in note 17 to the Company’s unaudited interim consolidated financial statements.

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

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from OPEC+ and its impact on world supply; the impact of geopolitical and market uncertainties, including those due to COVID-19 and in connection with governmental responses to COVID-19, on worldwide benchmark pricing; the impact of shale oil production in North America; the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America 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 increased significantly in the first quarter of 2021, partially in response to the OPEC+ decision to maintain production cut agreements implemented in the first half of 2020. Additionally, global demand for crude oil increased due to improved economic conditions, partially as a result of the availability of COVID-19 vaccines. WTI benchmark pricing averaged US$57.80 per bbl and the WCS Heavy Differential averaged US$12.42 per bbl in the first quarter of 2021. Economic conditions and the outlook for crude oil prices remain somewhat uncertain due to the impact of recent COVID-19 variants of concern and the timing of the roll-out of vaccines, which have the potential to delay the recovery of global economic conditions.

The Company continues to be nimble and act decisively to address the impacts of COVID-19 on its business and make appropriate operational improvements to increase efficiencies, including the optimization of the production profile across its diverse asset base and through its focus on cost control and efficiencies. The Company is also working diligently to reduce production costs wherever possible, asking all stakeholders to contribute to the sustainability of operations.

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

Liquidity

As at March 31, 2021, the Company had undrawn revolving bank credit facilities of $4,959 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,547 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. At March 31, 2021, the Company had $145 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

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

Capital Spending

Safe, reliable, effective and efficient operations continue to be a focus for the Company. On December 9, 2020, the Company announced its 2021 capital budget targeted at approximately $3,205 million, of which $1,345 million 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 statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Risks and Uncertainties

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

Benchmark Commodity Prices

(Average for the period)		Three Months Ended Mar 31 2021		Dec 31 2020		Mar 31 2020
WTI benchmark price (US$/bbl)	**$**	**57.80**	$	42.67	$	46.08
Dated Brent benchmark price (US$/bbl)	**$**	**60.58**	$	44.52	$	50.42
WCS Heavy Differential from WTI (US$/bbl)	**$**	**12.42**	$	9.30	$	20.47
SCO price (US$/bbl)	**$**	**54.30**	$	39.69	$	43.39
Condensate benchmark price (US$/bbl)	**$**	**57.99**	$	42.54	$	45.54
Condensate Differential from WTI (US$/bbl)	**$**	**(0.19)**	$	0.13	$	0.54
NYMEX benchmark price (US$/MMBtu)	**$**	**2.69**	$	2.66	$	1.95
AECO benchmark price (C$/GJ)	**$**	**2.77**	$	2.62	$	2.03
US/Canadian dollar average exchange rate (US$)	**$**	**0.7900**	$	0.7674	$	0.7434

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 was successful in mitigating the discount in crude oil pricing received in Alberta for both light crude oil and heavy crude oil. The 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$57.80 per bbl for the first quarter of 2021, an increase of 25% from US$46.08 per bbl for the first quarter of 2020, and an increase of 35% from US$42.67 per bbl for the fourth 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$60.58 per bbl for the first quarter of 2021, an increase of 20% from US$50.42 per bbl for the first quarter of 2020, and an increase of 36% from US$44.52 per bbl for the fourth quarter of 2020.

The increase in WTI and Brent pricing for the first quarter of 2021 from the comparable periods reflected the OPEC+ decision to maintain production cut agreements implemented in the first half of 2020. Additionally, global demand for crude oil increased due to improved economic conditions, partially as a result of the availability of COVID-19 vaccines.

The WCS Heavy Differential averaged US$12.42 per bbl for the first quarter of 2021, narrowing by 39% from US$20.47 per bbl for the first quarter of 2020, and widening by 34% from US$9.30 per bbl for the fourth quarter of 2020. The narrowing of the WCS Heavy Differential for the first quarter of 2021 from the first quarter of 2020 primarily reflected continued recovery in North American refining demand. The widening of the WCS Heavy Differential for the first quarter of 2021 from the fourth quarter of 2020 primarily reflected increased supply from the Basin due to the suspension of mandatory Government of Alberta curtailment, effective December 1, 2020.

The SCO price averaged US$54.30 per bbl for the first quarter of 2021, an increase of 25% from US$43.39 per bbl for the first quarter of 2020, and an increase of 37% from US$39.69 per bbl for the fourth quarter of 2020. The increase in SCO pricing for the first quarter of 2021 from the comparable periods of 2020 primarily reflected an increase in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.69 per MMBtu for the first quarter of 2021, an increase of 38% from US$1.95 per MMBtu for the first quarter of 2020, and comparable with US$2.66 per MMBtu for the fourth quarter of 2020. The increase in NYMEX natural gas prices for the first quarter of 2021 from the first quarter of 2020 primarily reflected increased domestic demand and LNG exports, together with lower production levels.

AECO natural gas prices averaged $2.77 per GJ for the first quarter of 2021, an increase of 36% from $2.03 per GJ for the first quarter of 2020, and an increase of 6% from $2.62 per GJ for the fourth quarter of 2020. The increase in AECO natural gas prices for the first quarter of 2021 from the comparable periods primarily reflected increased intra-provincial and export demand.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**478,736**	475,889	456,877
North America – Oil Sands Mining and Upgrading [1]	**468,803**	417,089	438,101
North Sea	**19,959**	17,057	27,755
Offshore Africa	**11,854**	17,155	15,943
	979,352	927,190	938,676
Natural gas (MMcf/d)			
North America	**1,585**	1,623	1,407
North Sea	**4**	4	23
Offshore Africa	**9**	17	10
	1,598	1,644	1,440
Total barrels of oil equivalent (BOE/d)	**1,245,703**	1,201,198	1,178,752
Product mix			
Light and medium crude oil and NGLs	**10%**	10%	11%
Pelican Lake heavy crude oil	**4%**	5%	5%
Primary heavy crude oil	**5%**	5%	7%
Bitumen (thermal oil)	**22%**	22%	20%
Synthetic crude oil [1]	**38%**	35%	37%
Natural gas	**21%**	23%	20%
Percentage of gross revenue [1] [2] (excluding Midstream and Refining revenue)			
Crude oil and NGLs	**92%**	90%	92%
Natural gas	**8%**	10%	8%

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

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

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**422,124**	433,697	414,460
North America – Oil Sands Mining and Upgrading	**448,315**	411,640	432,936
North Sea	**19,927**	17,023	27,693
Offshore Africa	**11,325**	16,416	15,296
	901,691	878,776	890,385
Natural gas (MMcf/d)			
North America	**1,508**	1,553	1,374
North Sea	**4**	4	23
Offshore Africa	**9**	16	10
	1,521	1,573	1,407
Total barrels of oil equivalent (BOE/d)	**1,155,220**	1,141,022	1,124,839

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

Record crude oil and NGLs production before royalties for the first quarter of 2021 averaged 979,352 bbl/d, an increase of 4% from 938,676 bbl/d for the first quarter of 2020, and an increase 6% from 927,190 bbl/d for the fourth quarter of 2020. Crude oil and NGLs production in North America Exploration and Production and Oil Sands Mining and Upgrading segments for the comparable periods in 2020 reflected the impact of the Company's curtailment optimization strategy during mandatory Government of Alberta curtailment. Production in the first quarter of 2021 primarily reflected high utilization in the Oil Sands Mining and Upgrading segment and strong thermal oil production following the suspension of mandatory Government of Alberta curtailment on December 1, 2020.

Natural gas production before royalties for the first quarter of 2021 of 1,598 MMcf/d increased 11% from 1,440 MMcf/d for the first quarter of 2020, and was comparable with 1,644 MMcf/d for the fourth quarter of 2020. The increase in natural gas production for the first quarter of 2021 from the first quarter of 2020 primarily reflected production volumes from the acquisition of Painted Pony on October 6, 2020, partially offset by natural field declines. Natural gas production also reflected a decrease of approximately 37 MMcf/d in the first quarter of 2021 due to a labour stoppage at the Pine River gas plant. Due to the poor economics at the facility, the Company anticipates that the plant will be placed in a decommissioned state, and remain offline indefinitely.

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

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the first quarter of 2021 of 478,736 bbl/d increased 5% from 456,877 bbl/d for the first quarter of 2020, and was comparable with 475,889 bbl/d for the fourth quarter of 2020. The increase in crude oil and NGLs production for the first quarter of 2021 from the first quarter of 2020 primarily reflected the impact of the suspension of mandatory Government of Alberta curtailment on December 1, 2020.

Thermal oil production before royalties for the first quarter of 2021 averaged 267,530 bbl/d, an increase of 17% from 228,303 bbl/d for the first quarter of 2020, and comparable with 266,179 bbl/d for the fourth quarter of 2020. The increase in thermal oil production for the first quarter of 2021 from the first quarter of 2020 reflected the impact of the Company's curtailment optimization strategy in the first quarter of 2020. Production in the first quarter of 2021 reflected high utilization at Jackfish and increased volumes at Kirby North following the suspension of mandatory Government of Alberta curtailment on December 1, 2020.

Pelican Lake heavy crude oil production before royalties averaged 55,498 bbl/d for the first quarter of 2021, a decrease of 4% from 57,986 bbl/d for the first quarter of 2020, and was comparable with 56,036 bbl/d for the fourth quarter of 2020, demonstrating Pelican Lake's long-life low decline production.

Natural gas production before royalties for the first quarter of 2021 averaged 1,585 MMcf/d, an increase of 13% from 1,407 MMcf/d for the first quarter of 2020, and comparable with 1,623 MMcf/d for the fourth quarter of 2020. The increase in natural gas production for the first quarter of 2021 from the first quarter of 2020 primarily reflected production volumes from the acquisition of Painted Pony on October 6, 2020, partially offset by the impact of natural field declines. Natural gas production also reflected a decrease of approximately 37 MMcf/d in the first quarter of 2021 due to a labour stoppage at the Pine River gas plant. Due to the poor economics at the facility, the Company anticipates that the plant will be placed in a decommissioned state, and remain offline indefinitely.

North America – Oil Sands Mining and Upgrading

Record SCO production before royalties for the first quarter of 2021 of 468,803 bbl/d increased 7% from 438,101 bbl/d for the first quarter of 2020 and increased 12% from 417,089 bbl/d for the fourth quarter of 2020. The increase in SCO production for the first quarter of 2021 from the comparable periods primarily reflected the completion of planned turnaround activities at Horizon early in the fourth quarter of 2020, and high utilization and operational enhancements at AOSP following the completion of expansion activities.

North Sea

North Sea crude oil production before royalties for the first quarter of 2021 decreased 28% to 19,959 bbl/d from 27,755 bbl/d for the first quarter of 2020 and increased 17% from 17,057 bbl/d for the fourth quarter of 2020. The decrease in production for the first quarter of 2021 from the first quarter of 2020 primarily reflected the permanent cessation of production at the Banff and Kyle fields on June 1, 2020 and natural field declines. The increase in production from the fourth quarter of 2020 primarily reflected the impact of planned turnaround activities during the fourth quarter of 2020, partially offset by natural field declines.

Offshore Africa

Offshore Africa crude oil production before royalties for the first quarter of 2021 of 11,854 bbl/d decreased 26% from 15,943 bbl/d for the first quarter of 2020 and decreased 31% from 17,155 bbl/d for the fourth quarter of 2020. The decrease in production for the first quarter of 2021 from the first quarter of 2020 primarily reflected planned turnaround activities at Baobab and natural field declines. The decrease in production for the first quarter of 2021 from the fourth quarter of 2020 primarily reflected planned turnaround activities at Baobab and an unplanned outage at Espoir during the first quarter of 2021.

International Crude Oil Inventory Volumes

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

(bbl)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
North Sea	**—**	450,889	—
Offshore Africa	**612,242**	521,244	532,347
	612,242	972,133	532,347

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 52.68**	$ 40.56	$ 25.90
Transportation (3)	**3.56**	3.81	3.87
Realized sales price, net of transportation	**49.12**	36.75	22.03
Royalties	**5.69**	3.34	2.34
Production expense	**14.56**	12.47	13.71
Netback	**$ 28.87**	$ 20.94	$ 5.98
Natural gas ($/Mcf) (1)			
Sales price (2)	**$ 3.42**	$ 2.94	$ 2.22
Transportation	**0.46**	0.42	0.46
Realized sales price, net of transportation	**2.96**	2.52	1.76
Royalties	**0.16**	0.13	0.05
Production expense	**1.27**	1.10	1.31
Netback	**$ 1.53**	$ 1.29	$ 0.40
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	**$ 41.80**	$ 32.61	$ 21.90
Transportation (3)	**3.29**	3.37	3.50
Realized sales price, net of transportation	**38.51**	29.24	18.40
Royalties	**4.10**	2.44	1.70
Production expense	**12.20**	10.43	11.87
Netback	**$ 22.21**	$ 16.37	$ 4.83

(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		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 50.67**	$ 39.54	$ 23.48
North Sea	**$ 75.16**	$ 56.18	$ 45.85
Offshore Africa	**$ 80.00**	$ 49.05	$ 58.16
Average	**$ 52.68**	$ 40.56	$ 25.90
Natural gas ($/Mcf) (1) (2)			
North America	**$ 3.41**	$ 2.91	$ 2.15
North Sea	**$ 2.57**	$ 1.41	$ 3.75
Offshore Africa	**$ 6.09**	$ 6.64	$ 8.94
Average	**$ 3.42**	$ 2.94	$ 2.22
Average ($/BOE) (1) (2)	**$ 41.80**	$ 32.61	$ 21.90

(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 averaged $50.67 per bbl for the first quarter of 2021, an increase of 116% compared with $23.48 per bbl for the first quarter of 2020 and an increase of 28% compared with $39.54 per bbl for the fourth quarter of 2020. The increase in realized crude oil prices for the first quarter of 2021 from the first quarter of 2020 was primarily due to higher WTI benchmark pricing together with the narrowing of the WCS Heavy Differential. The increase in realized crude oil prices for the first quarter of 2021 from the fourth quarter of 2020 was primarily due to higher WTI benchmark pricing, partially offset by the widening of the WCS Heavy Differential primarily reflecting increased supply from the Basin due to the suspension of mandatory Government of Alberta curtailment, effective December 1, 2020. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2021 contributed approximately 140,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 59% to average $3.41 per Mcf for the first quarter of 2021 from $2.15 per Mcf for the first quarter of 2020 and increased 17% from $2.91 per Mcf for the fourth quarter of 2020. The increase in realized natural gas prices for the first quarter of 2021 from the comparable periods primarily reflected increased intra-provincial and export demand.

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

	Three Months Ended		
(Quarterly average)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 50.54**	$ 38.03	$ 38.15
Pelican Lake heavy crude oil ($/bbl)	**$ 55.26**	$ 43.21	$ 27.75
Primary heavy crude oil ($/bbl)	**$ 54.24**	$ 42.01	$ 25.01
Bitumen (thermal oil) ($/bbl)	**$ 48.92**	$ 38.67	$ 16.53
Natural gas ($/Mcf)	**$ 3.41**	$ 2.91	$ 2.15

(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 increased 64% to average $75.16 per bbl for the first quarter of 2021 from $45.85 per bbl for the first quarter of 2020 and increased 34% from $56.18 per bbl for the fourth 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 increase in realized crude oil prices for the first quarter of 2021 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 38% to average $80.00 per bbl for the first quarter of 2021 from $58.16 per bbl for the first quarter of 2020 and increased 63% from $49.05 per bbl for the fourth 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 increase in realized crude oil prices for the first quarter of 2021 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 6.09**	$ 3.52	$ 2.49
North Sea	**$ 0.12**	$ 0.11	$ 0.10
Offshore Africa	**$ 3.57**	$ 2.11	$ 2.36
Average	**$ 5.69**	$ 3.34	$ 2.34
Natural gas ($/Mcf) (1)			
North America	**$ 0.16**	$ 0.13	$ 0.05
Offshore Africa	**$ 0.28**	$ 0.30	$ 0.51
Average	**$ 0.16**	$ 0.13	$ 0.05
Average ($/BOE) (1)	**$ 4.10**	$ 2.44	$ 1.70

(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 first quarter of 2021 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates averaged approximately 12% of product sales for the first quarter of 2021 compared with 11% for the first quarter of 2020 and 9% for the fourth quarter of 2020. The increase in royalty rates for the first quarter of 2021 from the comparable periods was primarily due to higher benchmark prices together with fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 5% of product sales for the first quarter of 2021 compared with 2% for the first quarter of 2020 and 4% for the fourth quarter of 2020. The increase in royalty rates for the first quarter of 2021 from the comparable periods was primarily due to higher benchmark pricing.

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 first quarter of 2021 and was comparable with 4% for the first quarter of 2020 and 4% for the fourth 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		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 12.80**	$ 10.81	$ 12.69
North Sea	**$ 42.24**	$ 52.42	$ 29.73
Offshore Africa	**$ 16.57**	$ 11.74	$ 11.88
Average	**$ 14.56**	$ 12.47	$ 13.71
Natural gas ($/Mcf) (1)			
North America	**$ 1.24**	$ 1.07	$ 1.24
North Sea	**$ 4.85**	$ 5.29	$ 3.45
Offshore Africa	**$ 4.99**	$ 3.07	$ 5.56
Average	**$ 1.27**	$ 1.10	$ 1.31
Average ($/BOE) (1)	**$ 12.20**	$ 10.43	$ 11.87

(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 first quarter of 2021 of $12.80 per bbl was comparable with $12.69 per bbl for the first quarter of 2020 and increased 18% from $10.81 per bbl for the fourth quarter of 2020. The increase in crude oil and NGLs production expense per bbl for the first quarter of 2021 from the comparable periods primarily reflected an increase in energy costs from the first quarter of 2020 and the fourth quarter of 2020, offsetting the impact of cost reductions as a result of the Company’s continuous focus on cost control. The increase in production expense per bbl for the first quarter of 2021 from the fourth quarter of 2020 also reflected seasonal conditions.

North America natural gas production expense for the first quarter of 2021 of $1.24 per Mcf was comparable with $1.24 per Mcf for the first quarter of 2020 and increased 16% from $1.07 per Mcf for the fourth quarter of 2020. The increase in natural gas production expense per Mcf for the first quarter of 2021 from the fourth quarter of 2020 primarily reflected the impact of an increase in electricity costs, together with the impact of seasonal conditions, offsetting the impact of cost reductions as a result of the Company’s continuous focus on cost control.

North Sea

North Sea crude oil production expense for the first quarter of 2021 of $42.24 per bbl increased 42% from $29.73 per bbl for the first quarter of 2020 and decreased 19% from $52.42 per bbl for the fourth quarter of 2020. The increase in crude oil production expense per bbl for the first quarter of 2021 from the first quarter of 2020 was primarily due to lower volumes on a relatively fixed cost base, higher energy costs, and the impact of timing of liftings from various fields that have different cost structures. The decrease in crude oil production expense per bbl for the first quarter of 2021 from the fourth quarter of 2020 was primarily due to higher volumes on a relatively fixed cost base. North Sea production expense also reflected fluctuations in the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the first quarter of 2021 of $16.57 per bbl increased 39% from $11.88 per bbl for the first quarter of 2020 and increased 41% from $11.74 per bbl for the fourth quarter of 2020. The increase in crude oil production expense per bbl for the first quarter of 2021 from the comparable periods primarily reflected the timing of liftings from various fields that have different cost structures and lower volumes on a relatively fixed cost base. Offshore Africa production expense also reflected fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
North America	**$ 868**	$ 1,017	$ 955
North Sea	**68**	61	99
Offshore Africa	**31**	54	41
Expense	**$ 967**	$ 1,132	$ 1,095
$/BOE (1)	**$ 13.70**	$ 15.55	$ 15.75

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

Depletion, depreciation and amortization expense for the first quarter of 2021 of $13.70 per BOE decreased 13% from $15.75 per BOE for the first quarter of 2020 and decreased 12% from $15.55 per BOE for the fourth quarter of 2020. The decrease in depletion, depreciation and amortization expense from the comparable periods primarily reflected lower depletion rates in the North America Exploration and Production segment, including the impact of the acquisition of Painted Pony in the fourth quarter of 2020.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
North America	**$ 25**	$ 24	$ 27
North Sea	**5**	8	7
Offshore Africa	**1**	1	1
Expense	**$ 31**	$ 33	$ 35
$/BOE (1)	**$ 0.45**	$ 0.45	$ 0.50

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

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

Asset retirement obligation accretion expense for the first quarter of 2021 of $0.45 per BOE decreased 10% from $0.50 per BOE for the first quarter of 2020 and was comparable with $0.45 per BOE for the fourth 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. Record SCO production in the first quarter of 2021 of 468,803 bbl/d reflected high utilization at Horizon and operational enhancements at AOSP following the completion of expansion activities.

The Company incurred production costs, excluding natural gas costs, of $779 million ($18.42 per bbl) for the first quarter of 2021, a 6% increase (2% decrease per bbl) from the fourth quarter of 2020.

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

	Three Months Ended		
($/bbl) [1]	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
SCO realized sales price [2]	**$ 64.60**	$ 48.56	$ 50.88
Bitumen value for royalty purposes [3]	**$ 46.39**	$ 34.70	$ 16.82
Bitumen royalties [4]	**$ 2.88**	$ 0.59	$ 0.87
Transportation	**$ 1.10**	$ 1.36	$ 1.28

(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 $64.60 per bbl for the first quarter of 2021, an increase of 27% from $50.88 per bbl for the first quarter of 2020 and an increase of 33% from $48.56 per bbl for the fourth quarter of 2020. The increase in the realized SCO sales price for the first quarter of 2021 from the comparable periods primarily reflected increases in WTI benchmark pricing.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended		
($ millions)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Production costs, excluding natural gas costs	**$ 779**	$ 736	$ 773
Natural gas costs	**59**	51	36
Production costs	**$ 838**	$ 787	$ 809

	Three Months Ended		
($/bbl) [1]	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Production costs, excluding natural gas costs	**$ 18.42**	$ 18.89	$ 19.83
Natural gas costs	**1.40**	1.31	0.93
Production costs	**$ 19.82**	$ 20.20	$ 20.76
Sales (bbl/d)	**469,953**	423,438	428,515

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

Production costs for the first quarter of 2021 averaged $19.82 per bbl, a decrease of 5% from $20.76 per bbl for the first quarter of 2020 and a decrease of 2% from $20.20 per bbl for the fourth quarter of 2020. The decrease in production costs per bbl for the first quarter of 2021 from the comparable periods primarily reflected higher reliability and operational enhancements at both Horizon and AOSP, offsetting the impact of higher energy costs, including natural gas costs, in the first quarter of 2021. 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		
($ millions, except per bbl amounts)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Expense	**$ 450**	$ 479	$ 440
$/bbl [1]	**$ 10.64**	$ 12.31	$ 11.28

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

Depletion, depreciation and amortization expense for the first quarter of 2021 of $10.64 per bbl decreased 6% from $11.28 per bbl for the first quarter of 2020 and decreased 14% from $12.31 per bbl for the fourth 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		
($ millions, except per bbl amounts)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Expense	**$ 15**	$ 18	$ 17
$/bbl [1]	**$ 0.34**	$ 0.47	$ 0.44

(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 of $0.34 per bbl for the first quarter of 2021 decreased 23% from $0.44 per bbl for the first quarter of 2020 and decreased 28% from $0.47 per bbl for the fourth quarter of 2020. Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

MIDSTREAM AND REFINING

	Three Months Ended		
($ millions)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Product sales			
Crude oil and NGLs, midstream activities	**$ 19**	$ 21	$ 21
NWRP, refined product sales	**131**	99	—
Segmented revenue	**150**	120	21
Less:			
Production expense			
NWRP, refining toll	**58**	72	—
Midstream	**5**	3	6
NWRP, transportation and feedstock costs	**105**	83	—
Depreciation	**4**	4	4
Segment earnings (loss) before taxes	**$ (22)**	$ (42)	$ 11

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 first quarter of 2021, production of ultra-low sulphur diesel and other refined products averaged 56,316 BOE/d (14,079 BOE/d to the Company).

The Company's unrecognized share of the equity (income) loss from NWRP for the first quarter of 2021 was a recovery of unrecognized losses of $17 million (three months ended March 31, 2020 – unrecognized equity loss of $93 million). As at March 31, 2021, the cumulative unrecognized share of losses from NWRP was $136 million (December 31, 2020 – $153 million).

ADMINISTRATION EXPENSE

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Expense	**$ 95**	$ 107	$ 108
$/BOE [(1)]	**$ 0.84**	$ 0.96	$ 1.00

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

Administration expense for the first quarter of 2021 of $0.84 per BOE decreased 16% from $1.00 per BOE for the first quarter of 2020 and decreased 13% from $0.96 per BOE for the fourth quarter of 2020. Administration expense per BOE decreased for the first quarter of 2021 from the comparable periods primarily due to the impact of lower personnel and corporate costs and higher sales volumes.

SHARE-BASED COMPENSATION

	Three Months Ended		
($ millions)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Expense (recovery)	**$ 129**	$ 123	$ (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 recorded a $129 million share-based compensation expense for the first quarter of 2021, primarily as a result of the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period, and changes in the Company's share price. Included within the share-based compensation expense for the first quarter of 2021 was $14 million related to PSUs granted to certain executive employees (March 31, 2020 – $7 million recovery). For the first quarter of 2021, the Company charged $1 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (March 31, 2020 – $1 million charged).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended		
($ millions, except per BOE amounts and interest rates)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Expense, gross	**$ 185**	$ 180	$ 214
Less: capitalized interest	**—**	3	8
Expense, net	**$ 185**	$ 177	$ 206
$/BOE [(1)]	**$ 1.64**	$ 1.59	$ 1.90
Average effective interest rate	**3.4%**	3.3%	3.9%

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

Net interest and other financing expense per BOE for the first quarter of 2021 decreased 14% to $1.64 per BOE from $1.90 per BOE for the first quarter of 2020 and increased 3% from $1.59 per BOE for the fourth quarter of 2020. The decrease in interest expense per BOE for the first quarter of 2021 from the first quarter of 2020 primarily reflected lower benchmark interest rates and lower average debt levels in the first quarter of 2021. The increase in interest expense per BOE for the first quarter of 2021 from the fourth quarter of 2020 was primarily due to higher benchmark interest rates in the first quarter of 2021.

The Company's average effective interest rate for the first quarter of 2021 decreased from the first quarter of 2020 primarily due to the impact of lower benchmark interest rates on the Company's outstanding bank credit facilities.

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		
($ millions)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Foreign currency contracts	**$ 15**	$ 25	$ (57)
Natural gas financial instruments	**(6)**	(2)	10
Realized loss (gain)	**9**	23	(47)
Foreign currency contracts	**(5)**	6	(9)
Natural gas financial instruments	**25**	(27)	(8)
Unrealized loss (gain)	**20**	(21)	(17)
Net loss (gain)	**$ 29**	$ 2	$ (64)

During the first quarter of 2021, the net realized risk management losses were related to the settlement of foreign currency contracts, partially offset by gains on natural gas financial instruments. The Company recorded a net unrealized loss of $20 million ($15 million after-tax) on its risk management activities for the first quarter of 2021 (three months ended December 31, 2020 – unrealized gain of $21 million; $16 million after-tax; three months ended March 31, 2020 – unrealized gain of $17 million; $15 million after-tax).

Further details related to outstanding derivative financial instruments at March 31, 2021 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended		
($ millions)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Net realized loss (gain)	**$ 10**	$ 21	$ (199)
Net unrealized (gain) loss	**(172)**	(534)	1,121
Net (gain) loss [1]	**$ (162)**	$ (513)	$ 922

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

The net realized foreign exchange loss for the first quarter of 2021 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling during the quarter. The net unrealized foreign exchange gain for the first quarter of 2021 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss 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 during the first quarter of 2020 (three months ended March 31, 2021 – unrealized loss of $10 million, three months ended December 31, 2020 – unrealized loss of $32 million, three months ended March 31, 2020 – unrealized loss of $74 million). The US/Canadian dollar exchange rate at March 31, 2021 was US$0.7954 (December 31, 2020 – US$0.7840, March 31, 2020 – US$0.7082).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Mar 31 2021	Dec 31 2020	Mar 31 2020
North America [1]	**$ 285**	$ 42	$ (194)
North Sea	**11**	—	9
Offshore Africa	**4**	5	4
PRT [2] – North Sea	**(5)**	(14)	—
Other taxes	**2**	2	2
Current income tax expense (recovery)	**297**	35	(179)
Deferred income tax expense (recovery)	**21**	(25)	20
	$ 318	$ 10	$ (159)
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**21%**	24%	36%

(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 first quarter of 2021 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings (loss).

The current corporate income tax and PRT in the North Sea for the first quarter of 2021 and the prior periods included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

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

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Mar 31 2021	Dec 31 2020	Mar 31 2020
Exploration and Evaluation			
Net property dispositions	**$ —**	$ (1)	$ (18)
Net expenditures	**4**	9	25
Total Exploration and Evaluation	**4**	8	7
Property, Plant and Equipment			
Net property acquisitions [2]	**1**	522	13
Well drilling, completion and equipping	**266**	115	202
Production and related facilities	**192**	131	214
Capitalized interest and other	**13**	20	12
Total Property, Plant and Equipment	**472**	788	441
Total Exploration and Production	**476**	796	448
Oil Sands Mining and Upgrading			
Project costs	**41**	86	56
Sustaining capital	**186**	212	201
Turnaround costs	**29**	22	23
Capitalized interest and other	**1**	4	9
Total Oil Sands Mining and Upgrading	**257**	324	289
Midstream and Refining	**2**	1	1
Abandonments [3]	**67**	52	89
Head office	**6**	3	11
Total net capital expenditures	**$ 808**	$ 1,176	$ 838
By segment			
North America [2]	**$ 419**	$ 729	$ 395
North Sea	**32**	34	26
Offshore Africa	**25**	33	27
Oil Sands Mining and Upgrading	**257**	324	289
Midstream and Refining	**2**	1	1
Abandonments [3]	**67**	52	89
Head office	**6**	3	11
Total	**$ 808**	$ 1,176	$ 838

(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 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.

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

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

($ millions)	Three Months Ended **Mar 31 2021**	Dec 31 2020	Mar 31 2020
Cash flows used in investing activities	***$ 648***	*$ 624*	*$ 859*
Net change in non-cash working capital	***93***	*(21)*	*(110)*
Repayment of NWRP subordinated debt advances (1)	***—***	*124*	*—*
Abandonment expenditures (2)	***67***	*52*	*89*
Other (3)	***—***	*397*	*—*
Net capital expenditures	***$ 808***	*$ 1,176*	*$ 838*

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

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

(3) 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 exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production expenses.

Net capital expenditures for the first quarter of 2021 were $808 million compared with $838 million for the first quarter of 2020 and $1,176 million for the fourth quarter of 2020.

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)

(number of wells)	Three Months Ended **Mar 31 2021**	Dec 31 2020	Mar 31 2020
Net successful natural gas wells	**22**	9	11
Net successful crude oil wells (2)	**44**	5	35
Stratigraphic test / service wells	**328**	—	367
Total	**394**	14	413
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	100%

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

(2) Includes bitumen wells.

North America

During the first quarter of 2021, the Company targeted 22 net natural gas wells, 27 net primary heavy crude oil wells, 3 net bitumen (thermal oil) wells and 12 net light crude oil wells.

North Sea

During the first quarter of 2021, the Company targeted 2 net light crude oil wells in the North Sea.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Mar 31 2021**		Dec 31 2020		Mar 31 2020
Working capital (1)	**$**	**626**	$	626	$	683
Long-term debt (2) (3)	**$**	**20,009**	$	21,453	$	22,687
Less: cash and cash equivalents		**166**		184		1,071
Long-term debt, net	**$**	**19,843**	$	21,269	$	21,616
Share capital	**$**	**9,685**	$	9,606	$	9,517
Retained earnings		**23,567**		22,766		23,425
Accumulated other comprehensive (loss) income		**(21)**		8		320
Shareholders' equity	**$**	**33,231**	$	32,380	$	33,262
Debt to book capitalization (3) (4)		**37.4%**		39.6%		39.4%
Debt to market capitalization (3) (5)		**30.1%**		37.0%		48.7%
After-tax return on average common shareholders' equity (6)		**6.8%**		(1.3)%		9.4%
After-tax return on average capital employed (3) (7)		**5.1%**		0.2%		6.8%

(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 March 31, 2021, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Business Environment" section of this MD&A and in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2020. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and market conditions. The Company continues to believe its internally generated cash flows from operating activities supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and

- Reviewing the Company's borrowing capacity:
  - During the first quarter of 2021, the $1,000 million non-revolving term credit facility, originally due February 2022, 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 2020, the Company repaid $162.5 million related to the required annual amortization. During the first quarter of 2021, the Company repaid a further $962.5 million on the facility, reducing the outstanding balance to $2,125 million, and exceeding the required annual amortization of $162.5 million originally due in June 2021. Subsequent to March 31, 2021, the Company repaid a further $650 million on the facility, reducing the outstanding balance to $1,475 million. The facility matures in June 2022.
  - As at March 31, 2021, 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.
  - As at March 31, 2021, 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.
  - Borrowings under the 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 March 31, 2021, the non-revolving term credit facilities were fully drawn.
  - Each of the $2,425 million revolving credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

As at March 31, 2021, the Company had undrawn revolving bank credit facilities of $4,959 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,547 million in liquidity. Additionally, the Company had in place fully drawn term credit facilities of $5,775 million. The Company also has certain other dedicated credit facilities supporting letters of credit. At March 31, 2021, the Company had $145 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

As at March 31, 2021, the Company had total US dollar denominated debt with a carrying amount of $15,785 million (US$12,555 million), before transaction costs and original issue discounts. This included $5,475 million (US$4,355 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$3,805 million). The fixed repayment amount of these hedging instruments is $5,419 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $56 million to $15,729 million as at March 31, 2021.

Net long-term debt was $19,843 million at March 31, 2021, resulting in a debt to book capitalization ratio of 37.4% (December 31, 2020 – 39.6%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities are greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at March 31, 2021 are discussed in note 8 of the Company's unaudited interim consolidated financial statements.

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

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. Further details related to the Company's commodity derivative financial instruments outstanding at March 31, 2021 are discussed in note 15 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)	$	1,772	$	7,024	$	3,138	$	8,178
Other long-term liabilities (2)	$	236	$	193	$	415	$	910
Interest and other financing expense (3)	$	747	$	659	$	1,553	$	4,266

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows: less than one year, $186 million; one to less than two years, $155 million; two to less than five years, $399 million; and thereafter, $910 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 March 31, 2021.

Share Capital

As at March 31, 2021, there were 1,185,685,000 common shares outstanding (December 31, 2020 – 1,183,866,000 common shares) and 56,293,000 stock options outstanding. As at May 4, 2021, the Company had 1,184,837,000 common shares outstanding and 55,757,000 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 (previous quarterly dividend rate of $0.425 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 9, 2021, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 59,278,474 common shares, over a 12-month period commencing March 11, 2021 and ending March 10, 2022.

For the three months ended March 31, 2021, the Company purchased 600,000 common shares at a weighted average price of $38.61 per common share for a total cost of $23 million. Retained earnings were reduced by $18 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2021, the Company purchased 960,000 common shares at a weighted average price of $38.15 per common share for a total cost of $37 million.

COMMITMENTS AND CONTINGENCIES

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

		Remaining 2021		2022		2023		2024		2025		Thereafter
Product transportation and processing (1)	$	661	$	826	$	879	$	842	$	809	$	10,365
North West Redwater Partnership service toll (2)	$	122	$	156	$	159	$	156	$	149	$	2,642
Offshore vessels and equipment	$	48	$	41	$	—	$	—	$	—	$	—
Field equipment and power	$	19	$	21	$	21	$	21	$	21	$	246
Other	$	18	$	21	$	20	$	21	$	21	$	16

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

(2) Pursuant to the processing agreements, 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 $1,092 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.

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 ended March 31, 2021, COVID-19 continued to have an impact on the global economy, including the oil and gas industry. Business conditions in the first quarter of 2021 continued to reflect the market uncertainty associated with COVID-19, with some improvements to global crude oil demand and supply conditions. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions, and judgements in the preparation of the unaudited interim consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the Company's annual MD&A and audited consolidated financial statements for the year ended December 31, 2020.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended March 31, 2021 that have materially affected, or are reasonably likely to materially affect the Company’s ICFR. Due to inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Mar 31 2021	Dec 31 2020
ASSETS			
Current assets			
Cash and cash equivalents		**$ 166**	$ 184
Accounts receivable		**2,783**	2,190
Current income taxes receivable		**—**	309
Inventory		**1,088**	1,060
Prepaids and other		**254**	231
Investments	6	**422**	305
Current portion of other long-term assets	7	**140**	82
		4,853	4,361
Exploration and evaluation assets	3	**2,415**	2,436
Property, plant and equipment	4	**65,135**	65,752
Lease assets	5	**1,599**	1,645
Other long-term assets	7	**1,125**	1,082
		$ 75,127	$ 75,276
LIABILITIES			
Current liabilities			
Accounts payable		**$ 759**	$ 667
Accrued liabilities		**2,693**	2,346
Current income taxes payable		**101**	—
Current portion of long-term debt	8	**1,772**	1,343
Current portion of other long-term liabilities	5, 9	**674**	722
		5,999	5,078
Long-term debt	8	**18,237**	20,110
Other long-term liabilities	5, 9	**7,501**	7,564
Deferred income taxes		**10,159**	10,144
		41,896	42,896
SHAREHOLDERS' EQUITY			
Share capital	11	**9,685**	9,606
Retained earnings		**23,567**	22,766
Accumulated other comprehensive (loss) income	12	**(21)**	8
		33,231	32,380
		$ 75,127	$ 75,276

Commitments and contingencies (note 16).

Approved by the Board of Directors on May 5, 2021.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Mar 31 2021	Mar 31 2020
Product sales	17	**$ 7,019**	$ 4,652
Less: royalties		**(411)**	(152)
Revenue		**6,608**	4,500
Expenses			
Production		**1,781**	1,684
Transportation, blending and feedstock		**1,508**	1,432
Depletion, depreciation and amortization	4, 5	**1,421**	1,564
Administration		**95**	108
Share-based compensation	9	**129**	(223)
Asset retirement obligation accretion	9	**46**	52
Interest and other financing expense		**185**	206
Risk management activities	15	**29**	(64)
Foreign exchange (gain) loss		**(162)**	922
(Gain) loss from investments	6	**(119)**	260
		4,913	5,941
Earnings (loss) before taxes		**1,695**	(1,441)
Current income tax expense (recovery)	10	**297**	(179)
Deferred income tax expense	10	**21**	20
Net earnings (loss)		**$ 1,377**	$ (1,282)
Net earnings (loss) per common share			
Basic	14	**$ 1.16**	$ (1.08)
Diluted	14	**$ 1.16**	$ (1.08)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2021	Mar 31 2020
Net earnings (loss)	**$ 1,377**	$ (1,282)
Items that may be reclassified subsequently to net earnings (loss)		
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized income during the period, net of taxes of $1 million (2020 – $5 million)	**11**	39
Reclassification to net earnings (loss), net of taxes of $1 million (2020 – $1 million)	**(4)**	(7)
	7	32
Foreign currency translation adjustment		
Translation of net investment	**(36)**	254
Other comprehensive (loss) income, net of taxes	**(29)**	286
Comprehensive income (loss)	**$ 1,348**	$ (996)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Mar 31 2021**	Mar 31 2020
Share capital	11		
Balance – beginning of period		**$ 9,606**	$ 9,533
Issued upon exercise of stock options		**73**	31
Previously recognized liability on stock options exercised for common shares		**11**	9
Purchase of common shares under Normal Course Issuer Bid		**(5)**	(56)
Balance – end of period		**9,685**	9,517
Retained earnings			
Balance – beginning of period		**22,766**	25,424
Net earnings (loss)		**1,377**	(1,282)
Dividends on common shares	11	**(558)**	(502)
Purchase of common shares under Normal Course Issuer Bid	11	**(18)**	(215)
Balance – end of period		**23,567**	23,425
Accumulated other comprehensive (loss) income	12		
Balance – beginning of period		**8**	34
Other comprehensive (loss) income, net of taxes		**(29)**	286
Balance – end of period		**(21)**	320
Shareholders' equity		**$ 33,231**	$ 33,262

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Mar 31 2021	Mar 31 2020
Operating activities			
Net earnings (loss)		**$ 1,377**	$ (1,282)
Non-cash items			
Depletion, depreciation and amortization		**1,421**	1,564
Share-based compensation		**129**	(223)
Asset retirement obligation accretion		**46**	52
Unrealized risk management loss (gain)		**20**	(17)
Unrealized foreign exchange (gain) loss		**(172)**	1,121
Realized foreign exchange gain on settlement of cross currency swaps		**—**	(166)
(Gain) loss from investments	6	**(117)**	268
Deferred income tax expense		**21**	20
Other		**(99)**	(118)
Abandonment expenditures		**(80)**	(89)
Net change in non-cash working capital		**(10)**	595
Cash flows from operating activities		**2,536**	1,725
Financing activities			
(Repayment) issue of bank credit facilities and commercial paper, net	8	**(1,400)**	649
Proceeds on settlement of cross currency swaps	15	**—**	166
Payment of lease liabilities	5, 9	**(53)**	(65)
Issue of common shares on exercise of stock options		**73**	31
Dividends on common shares		**(503)**	(444)
Purchase of common shares under Normal Course Issuer Bid	11	**(23)**	(271)
Cash flows (used in) from financing activities		**(1,906)**	66
Investing activities			
Net expenditures on exploration and evaluation assets		**(4)**	(7)
Net expenditures on property, plant and equipment		**(737)**	(742)
Net change in non-cash working capital		**93**	(110)
Cash flows used in investing activities		**(648)**	(859)
(Decrease) increase in cash and cash equivalents		**(18)**	932
Cash and cash equivalents – beginning of period		**184**	139
Cash and cash equivalents – end of period		**$ 166**	$ 1,071
Interest paid on long-term debt, net		**$ 212**	$ 213
Income taxes (received) paid		**$ (121)**	$ 41

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("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, 2020, except as disclosed in note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2020.

Critical Accounting Estimates and Judgements

For the three months ended March 31, 2021, the novel coronavirus ("COVID-19") continued to have an impact on the global economy, including the oil and gas industry. Business conditions in the first quarter of 2021 continued to reflect the market uncertainty associated with COVID-19, with some improvements to global crude oil demand and supply conditions. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions and judgements in the preparation of the unaudited interim consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Actual results may differ from estimated amounts, and those differences may be material.

2. CHANGES IN ACCOUNTING POLICIES

In August 2020, the IASB issued Interest Rate Benchmark Reform (Phase 2) in response to the Financial Stability Board's mandated reforms to InterBank Offered Rates ("IBORs"), with financial regulators proposing that current IBOR benchmark rates be replaced by a number of new local currency denominated alternative benchmark rates. The Company retrospectively adopted the amendments on January 1, 2021. Adoption of these amendments did not have a significant impact on the Company's financial statements.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2020	$ 2,101	$ —	$ 83	$ 252	$ 2,436
Additions	**2**	**—**	**2**	**—**	**4**
Transfers to property, plant and equipment	**(25)**	**—**	**—**	**—**	**(25)**
At March 31, 2021	**$ 2,078**	**$ —**	**$ 85**	**$ 252**	**$ 2,415**

4. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2020	$ 73,997	$ 7,283	$ 3,963	$ 45,710	$ 457	$ 485	$ 131,895
Additions	**419**	**32**	**23**	**257**	**2**	**6**	**739**
Transfers from E&E assets	**25**	**—**	**—**	**—**	**—**	**—**	**25**
Derecognitions (1)	**(83)**	**—**	**—**	**(7)**	**—**	**—**	**(90)**
Foreign exchange adjustments and other	**—**	**(106)**	**(57)**	**—**	**—**	**—**	**(163)**
At March 31, 2021	**$ 74,358**	**$ 7,209**	**$ 3,929**	**$ 45,960**	**$ 459**	**$ 491**	**$ 132,406**
Accumulated depletion and depreciation							
At December 31, 2020	$ 49,641	$ 5,853	$ 2,822	$ 7,289	$ 168	$ 370	$ 66,143
Expense	**844**	**65**	**24**	**421**	**4**	**6**	**1,364**
Derecognitions (1)	**(83)**	**—**	**—**	**(7)**	**—**	**—**	**(90)**
Foreign exchange adjustments and other	**1**	**(105)**	**(40)**	**(2)**	**—**	**—**	**(146)**
At March 31, 2021	**$ 50,403**	**$ 5,813**	**$ 2,806**	**$ 7,701**	**$ 172**	**$ 376**	**$ 67,271**
Net book value							
- at March 31, 2021	**$ 23,955**	**$ 1,396**	**$ 1,123**	**$ 38,259**	**$ 287**	**$ 115**	**$ 65,135**
- at December 31, 2020	$ 24,356	$ 1,430	$ 1,141	$ 38,421	$ 289	$ 115	$ 65,752

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

5. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2020	$ 1,038	$ 379	$ 128	$ 100	$ 1,645
Additions	**—**	**11**	**—**	**2**	**13**
Depreciation	**(30)**	**(14)**	**(7)**	**(6)**	**(57)**
Foreign exchange adjustments and other	**—**	**—**	**(2)**	**—**	**(2)**
At March 31, 2021	**$ 1,008**	**$ 376**	**$ 119**	**$ 96**	**$ 1,599**

Lease liabilities

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

	Mar 31 2021	Dec 31 2020
Lease liabilities	**$ 1,650**	$ 1,690
Less: current portion	**186**	189
	$ 1,464	$ 1,501

Total cash outflows for leases for the three months ended March 31, 2021, including payments related to short-term leases not reported as lease assets, were $288 million (March 31, 2020 – $319 million). Interest expense on leases for the three months ended March 31, 2021 was $16 million (March 31, 2020 – $17 million).

6. INVESTMENTS

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

	Mar 31 2021	Dec 31 2020
Investment in PrairieSky Royalty Ltd.	**$ 307**	$ 228
Investment in Inter Pipeline Ltd.	**115**	77
	$ 422	$ 305

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

	Three Months Ended	
	Mar 31 2021	Mar 31 2020
Fair value (gain) loss from investments	**$ (117)**	$ 268
Dividend income from investments	**(2)**	(8)
	$ (119)	$ 260

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 March 31, 2021, 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 March 31, 2021 the market price per common share was $13.55 (December 31, 2020 – $10.09; March 31, 2020 – $7.43).

The Company's investment in Inter Pipeline consists of 6.4 million common shares. As at March 31, 2021 the market price per common share was $17.97 (December 31, 2020 – $11.87; March 31, 2020 – $8.42).

7. OTHER LONG-TERM ASSETS

	Mar 31 2021	Dec 31 2020
North West Redwater Partnership	**$ 555**	$ 555
Prepaid cost of service toll	**160**	162
Risk management (note 15)	**143**	136
Long-term inventory	**131**	121
Other [(1)]	**276**	190
	1,265	1,164
Less: current portion	**140**	82
	$ 1,125	$ 1,082

(1) Includes physical product sales contracts valued at $103 million at March 31, 2021 (December 31, 2020 - $111 million).

The Company has a 50% equity investment in and as at March 31, 2021 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%. 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 16). 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 March 31, 2021 was a recovery of unrecognized equity losses of $17 million (three months ended March 31, 2020 – unrecognized equity loss of $93 million). As at March 31, 2021, the cumulative unrecognized share of equity losses from NWRP was $136 million (December 31, 2020 – $153 million; March 31, 2020 – $152 million).

8. LONG-TERM DEBT

	Mar 31 2021	Dec 31 2020
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 1,127**	$ 1,614
Medium-term notes	**3,200**	3,200
	4,327	4,814
US dollar denominated debt, unsecured		
Bank credit facilities (March 31, 2021 – US$3,690 million; December 31, 2020 - US$3,953 million)	**4,639**	5,041
Commercial paper (March 31, 2021 – US$115 million; December 31, 2020 – US$426 million)	**145**	544
US dollar debt securities (March 31, 2021 – US$8,750 million; December 31, 2020 – US$8,750 million)	**11,001**	11,161
	15,785	16,746
Long-term debt before transaction costs and original issue discounts, net	**20,112**	21,560
Less: original issue discounts, net (1)	**17**	18
transaction costs (1) (2)	**86**	89
	20,009	21,453
Less: current portion of commercial paper	**145**	544
current portion of other long-term debt (1) (2)	**1,627**	799
	$ 18,237	$ 20,110

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

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

Bank Credit Facilities and Commercial Paper

As at March 31, 2021, the Company had undrawn revolving bank credit facilities of $4,959 million. Additionally, the Company had in place fully drawn term credit facilities of $5,775 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit. At March 31, 2021, the Company had $145 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 $2,425 million revolving syndicated credit facility maturing June 2022;
- a $2,125 million non-revolving term credit facility maturing June 2022;
- a $1,000 million non-revolving term credit facility maturing February 2023;
- 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 first quarter of 2021, the $1,000 million non-revolving term credit facility, originally due February 2022, 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 2020, the Company repaid $162.5 million related to the required annual amortization. During the first quarter of 2021, the Company repaid a further $962.5 million on the facility, reducing the outstanding balance to $2,125 million, and exceeding the required annual amortization of $162.5 million originally due in June 2021. Subsequent to March 31, 2021, the Company repaid a further $650 million on the facility, reducing the outstanding balance to $1,475 million. 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 March 31, 2021 was 1.1% (March 31, 2020 – 2.2%), and on total long-term debt outstanding for the three months ended March 31, 2021 was 3.3% (March 31, 2020 – 3.9%).

As at March 31, 2021, letters of credit and guarantees aggregating to $506 million were outstanding.

Medium-Term Notes

As at March 31, 2021, 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.

US Dollar Debt Securities

As at March 31, 2021, 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.

9. OTHER LONG-TERM LIABILITIES

	Mar 31 2021	Dec 31 2020
Asset retirement obligations	**$ 5,816**	$ 5,861
Lease liabilities (note 5)	**1,650**	1,690
Share-based compensation	**278**	160
Risk management (note 15)	**57**	160
Transportation and processing contracts	**259**	270
Other (1)	**115**	145
	8,175	8,286
Less: current portion	**674**	722
	$ 7,501	$ 7,564

(1) Includes $47 million related to the acquisition of the Joslyn oil sands project in 2018, payable in annual installments of $25 million over the next two years.

Asset Retirement Obligations

The Company’s asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 3.7% (December 31, 2020 – 3.7%) and inflation rates of up to 2% (December 31, 2020 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Mar 31 2021	Dec 31 2020
Balance – beginning of period	**$ 5,861**	$ 5,771
Liabilities incurred	**2**	5
Liabilities acquired, net	**—**	13
Liabilities settled	**(80)**	(249)
Asset retirement obligation accretion	**46**	205
Revision of cost and timing estimates	**—**	(134)
Change in discount rates	**—**	253
Foreign exchange adjustments	**(13)**	(3)
Balance – end of period	**5,816**	5,861
Less: current portion	**158**	184
	$ 5,658	$ 5,677

Share-Based Compensation

The liability for share-based compensation includes costs incurred under the Company’s Stock Option Plan and Performance Share Unit ("PSU") plans. The Company’s Stock Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met.

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

	Mar 31 2021	Dec 31 2020
Balance – beginning of period	**$ 160**	$ 297
Share-based compensation expense (recovery)	**129**	(82)
Cash payment for stock options surrendered and PSUs vested	**(1)**	(39)
Transferred to common shares	**(11)**	(21)
Charged to Oil Sands Mining and Upgrading, net	**1**	5
Balance – end of period	**278**	160
Less: current portion	**208**	119
	$ 70	$ 41

Included within share-based compensation liability as at March 31, 2021 was $63 million related to PSUs granted to certain executive employees (December 31, 2020 – $49 million).

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended			
Expense (recovery)		**Mar 31 2021**		Mar 31 2020
Current corporate income tax – North America	**$**	**285**	$	(194)
Current corporate income tax – North Sea		**11**		9
Current corporate income tax – Offshore Africa		**4**		4
Current PRT [(1)] – North Sea		**(5)**		—
Other taxes		**2**		2
Current income tax		**297**		(179)
Deferred income tax		**21**		20
Income tax	**$**	**318**	$	(159)

(1) Petroleum Revenue Tax.

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Three Months Ended Mar 31, 2021		
Issued common shares	**Number of shares** (thousands)		**Amount**
Balance – beginning of period	**1,183,866**	**$**	**9,606**
Issued upon exercise of stock options	**2,419**		**73**
Previously recognized liability on stock options exercised for common shares	**—**		**11**
Purchase of common shares under Normal Course Issuer Bid	**(600)**		**(5)**
Balance – end of period	**1,185,685**	**$**	**9,685**

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 was payable on April 5, 2021.

Normal Course Issuer Bid

On March 9, 2021, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 59,278,474 common shares, over a 12-month period commencing March 11, 2021 and ending March 10, 2022.

For the three months ended March 31, 2021, the Company purchased 600,000 common shares at a weighted average price of $38.61 per common share for a total cost of $23 million. Retained earnings were reduced by $18 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2021, the Company purchased 960,000 common shares at a weighted average price of $38.15 per common share for a total cost of $37 million.

Share-Based Compensation – Stock Options

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

	Three Months Ended Mar 31, 2021		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**48,656**	**$**	**37.53**
Granted	**11,275**	**$**	**32.85**
Exercised for common shares	**(2,419)**	**$**	**29.99**
Surrendered for cash settlement	**(127)**	**$**	**32.40**
Forfeited	**(1,092)**	**$**	**35.01**
Outstanding – end of period	**56,293**	**$**	**36.98**
Exercisable – end of period	**17,935**	**$**	**40.64**

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

12. ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

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

		Mar 31 2021		Mar 31 2020
Derivative financial instruments designated as cash flow hedges	**$**	**76**	$	103
Foreign currency translation adjustment		**(97)**		217
	$	**(21)**	$	320

13. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At March 31, 2021, the ratio was within the target range at 37.4%.

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

		Mar 31 2021		Dec 31 2020
Long-term debt, net [1]	**$**	**19,843**	$	21,269
Total shareholders' equity	**$**	**33,231**	$	32,380
Debt to book capitalization		**37.4%**		39.6%

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

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

14. NET EARNINGS (LOSS) PER COMMON SHARE

		Three Months Ended	
		Mar 31 2021	Mar 31 2020
Weighted average common shares outstanding – basic (thousands of shares)		**1,185,551**	1,183,138
Effect of dilutive stock options (thousands of shares)		**1,661**	—
Weighted average common shares outstanding – diluted (thousands of shares)		**1,187,212**	1,183,138
Net earnings (loss)		**$ 1,377**	$ (1,282)
Net earnings (loss) per common share	– basic	**$ 1.16**	$ (1.08)
	– diluted	**$ 1.16**	$ (1.08)

15. FINANCIAL INSTRUMENTS

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

	Mar 31, 2021				
Asset (liability)	**Financial assets at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 2,783**	**$ —**	**$ —**	**$ —**	**$ 2,783**
Investments	**—**	**422**	**—**	**—**	**422**
Other long-term assets	**555**	**—**	**143**	**—**	**698**
Accounts payable	**—**	**—**	**—**	**(759)**	**(759)**
Accrued liabilities	**—**	**—**	**—**	**(2,693)**	**(2,693)**
Other long-term liabilities (1)	**—**	**(57)**	**—**	**(1,697)**	**(1,754)**
Long-term debt (2)	**—**	**—**	**—**	**(20,009)**	**(20,009)**
	$ 3,338	**$ 365**	**$ 143**	**$ (25,158)**	**$ (21,312)**

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

(1) Includes $1,650 million of lease liabilities (December 31, 2020 – $1,690 million) and $47 million of deferred purchase consideration payable over the next two years (December 31, 2020 – $72 million).

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

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

	Mar 31, 2021			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3** (4) (5)
Investments (3)	**$ 422**	**$ 422**	**$ —**	**$ —**
Other long-term assets	**$ 698**	**$ —**	**$ 143**	**$ 555**
Other long-term liabilities	**$ (104)**	**$ —**	**$ (57)**	**$ (47)**
Fixed rate long-term debt (6) (7)	**$ (14,098)**	**$ (15,836)**	**$ —**	**$ —**

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

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

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

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

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

(5) The fair value of NWRP subordinated debt 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)		**Mar 31 2021**		Dec 31 2020
Derivatives held for trading				
Natural gas fixed price swaps	**$**	**(10)**	$	(5)
Natural gas basis swaps		**(45)**		(40)
Foreign currency forward contracts		**(2)**		(7)
Cash flow hedges				
Foreign currency forward contracts		**8**		(108)
Cross currency swaps		**135**		136
	$	**86**	$	(24)
Included within:				
Current portion of other long-term assets	**$**	**14**	$	5
Current portion of other long-term liabilities		**(25)**		(131)
Other long-term assets		**129**		131
Other long-term liabilities		**(32)**		(29)
	$	**86**	$	(24)

For the three months ended March 31, 2021, the ineffectiveness arising from cash flow hedges was a gain of $1 million (year ended December 31, 2020 – loss of $1 million).

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

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

Asset (liability)		**Mar 31 2021**		Dec 31 2020
Balance – beginning of period	**$**	**(24)**	$	178
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**(4)**		(32)
Foreign exchange		**107**		(168)
Other comprehensive income (loss)		**7**		(2)
Balance – end of period		**86**		(24)
Less: current portion		**(11)**		(126)
	$	**97**	$	102

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

	Three Months Ended	
	Mar 31 2021	Mar 31 2020
Net realized risk management loss (gain)	**$ 9**	$ (47)
Net unrealized risk management loss (gain)	**20**	(17)
	$ 29	$ (64)

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 March 31, 2021, 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	Apr 2021 - Dec 2021	34,558 GJ/d	$2.00/GJ	AECO
	Apr 2021 - Dec 2021	28,291 MMBtu/d	US$2.41/MMBtu	DAWN
	Apr 2021 - Dec 2021	19,436 MMBtu/d	US$2.51/MMBtu	NYMEX
	Apr 2021 - Dec 2021	15,000 MMBtu/d	US$2.62/MMBtu	SUMAS
Differential swap	Apr 2021 - Aug 2021	20,000 GJ/d	$0.29/GJ	AECO-STN 2
Basis swap	Apr 2021 - Dec 2023	54,527 MMBtu/d	US$1.24/MMBtu	AECO
	Jan 2024 - Dec 2025	20,000 MMBtu/d	US$0.97/MMBtu	AECO
	Apr 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 March 31, 2021, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

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

At March 31, 2021, the Company had the following cross currency swap contract outstanding:

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

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

In addition to the cross currency swap contract noted above, at March 31, 2021, the Company had US$4,373 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$3,805 million designated as cash flow hedges.

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At March 31, 2021, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At March 31, 2021, the Company had net risk management assets of $141 million with specific counterparties related to derivative financial instruments (December 31, 2020 – $129 million).

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

c) Liquidity risk

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

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

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	$ 759	$ —	$ —	$ —
Accrued liabilities	$ 2,693	$ —	$ —	$ —
Long-term debt (1)	$ 1,772	$ 7,024	$ 3,138	$ 8,178
Other long-term liabilities (2)	$ 236	$ 193	$ 415	$ 910
Interest and other financing expense (3)	$ 747	$ 659	$ 1,553	$ 4,266

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, $186 million; one to less than two years, $155 million; two to less than five years, $399 million; and thereafter $910 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 March 31, 2021.

16. COMMITMENTS AND CONTINGENCIES

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

	Remaining 2021	2022	2023	2024	2025	Thereafter
Product transportation and processing (1)	$ 661	$ 826	$ 879	$ 842	$ 809	$ 10,365
North West Redwater Partnership service toll (2)	$ 122	$ 156	$ 159	$ 156	$ 149	$ 2,642
Offshore vessels and equipment	$ 48	$ 41	$ —	$ —	$ —	$ —
Field equipment and power	$ 19	$ 21	$ 21	$ 21	$ 21	$ 246
Other	$ 18	$ 21	$ 20	$ 21	$ 21	$ 16

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

(2) Pursuant to the processing agreements, 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 $1,092 million of interest payable over the 30-year tolling period (note 7).

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

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

17. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America Three Months Ended Mar 31 **2021**	2020	North Sea Three Months Ended Mar 31 **2021**	2020	Offshore Africa Three Months Ended Mar 31 **2021**	2020	Total Exploration and Production Three Months Ended Mar 31 **2021**	2020
Segmented product sales								
Crude oil and NGLs	**3,095**	1,850	**200**	133	**78**	84	**3,373**	2,067
Natural gas	**486**	275	**1**	8	**5**	8	**492**	291
Other income and revenue [1]	**31**	(10)	**—**	1	**2**	2	**33**	(7)
Total segmented product sales	**3,612**	2,115	**201**	142	**85**	94	**3,898**	2,351
Less: royalties	**(285)**	(114)	**—**	—	**(4)**	(4)	**(289)**	(118)
Segmented revenue	**3,327**	2,001	**201**	142	**81**	90	**3,609**	2,233
Segmented expenses								
Production	**727**	709	**114**	94	**21**	22	**862**	825
Transportation, blending and feedstock	**1,146**	1,070	**2**	7	**—**	—	**1,148**	1,077
Depletion, depreciation and amortization	**868**	955	**68**	99	**31**	41	**967**	1,095
Asset retirement obligation accretion	**25**	27	**5**	7	**1**	1	**31**	35
Risk management activities (commodity derivatives)	**19**	2	**—**	—	**—**	—	**19**	2
Total segmented expenses	**2,785**	2,763	**189**	207	**53**	64	**3,027**	3,034
Segmented earnings (loss) before the following	**542**	(762)	**12**	(65)	**28**	26	**582**	(801)
Non–segmented expenses								
Administration								
Share-based compensation								
Interest and other financing expense								
Risk management activities (other)								
Foreign exchange (gain) loss								
(Gain) loss from investments								
Total non–segmented expenses								
Earnings (loss) before taxes								
Current income tax expense (recovery)								
Deferred income tax expense								
Net earnings (loss)								

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading Three Months Ended Mar 31 2021	 2020	Midstream and Refining Three Months Ended Mar 31 2021	 2020	Inter–segment elimination and other Three Months Ended Mar 31 2021	 2020	Total Three Months Ended Mar 31 2021	 2020
Segmented product sales								
Crude oil and NGLs [2]	**2,983**	2,204	**19**	21	**(87)**	31	**6,288**	4,323
Natural gas	**—**	—	**—**	—	**63**	46	**555**	337
Other income and revenue [1]	**10**	(3)	**131**	—	**2**	2	**176**	(8)
Total segmented product sales	**2,993**	2,201	**150**	21	**(22)**	79	**7,019**	4,652
Less: royalties	**(122)**	(34)	**—**	—	**—**	—	**(411)**	(152)
Segmented revenue	**2,871**	2,167	**150**	21	**(22)**	79	**6,608**	4,500
Segmented expenses								
Production	**838**	809	**63**	6	**18**	44	**1,781**	1,684
Transportation, blending and feedstock [2]	**297**	270	**105**	—	**(42)**	85	**1,508**	1,432
Depletion, depreciation and amortization	**450**	440	**4**	4	**—**	25	**1,421**	1,564
Asset retirement obligation accretion	**15**	17	**—**	—	**—**	—	**46**	52
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**19**	2
Total segmented expenses	**1,600**	1,536	**172**	10	**(24)**	154	**4,775**	4,734
Segmented earnings (loss) before the following	**1,271**	631	**(22)**	11	**2**	(75)	**1,833**	(234)
Non–segmented expenses								
Administration							**95**	108
Share-based compensation							**129**	(223)
Interest and other financing expense							**185**	206
Risk management activities (other)							**10**	(66)
Foreign exchange (gain) loss							**(162)**	922
(Gain) loss from investments							**(119)**	260
Total non–segmented expenses							**138**	1,207
Earnings (loss) before taxes							**1,695**	(1,441)
Current income tax expense (recovery)							**297**	(179)
Deferred income tax expense							**21**	20
Net earnings (loss)							**1,377**	(1,282)

(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 cost of lease contracts.
(2) Includes blending and feedstock costs associated with the processing of third party bitumen and other purchased feedstock in the Oil Sands Mining and Upgrading segment.

Capital Expenditures [1]

	Three Months Ended					
	Mar 31, 2021			Mar 31, 2020		
	Net expenditures	**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	**$ 2**	**$ (25)**	**$ (23)**	$ 6	$ (17)	$ (11)
Offshore Africa	**2**	**—**	**2**	1	—	1
	$ 4	**$ (25)**	**$ (21)**	$ 7	$ (17)	$ (10)
Property, plant and equipment						
Exploration and Production						
North America	**$ 417**	**$ (56)**	**$ 361**	$ 389	$ (919)	$ (530)
North Sea	**32**	**—**	**32**	26	(114)	(88)
Offshore Africa	**23**	**—**	**23**	26	(29)	(3)
	472	**(56)**	**416**	441	(1,062)	(621)
Oil Sands Mining and Upgrading [3]	**257**	**(7)**	**250**	289	(459)	(170)
Midstream and Refining	**2**	**—**	**2**	1	—	1
Head office	**6**	**—**	**6**	11	—	11
	$ 737	**$ (63)**	**$ 674**	$ 742	$ (1,521)	$ (779)

(1) This table provides a reconciliation of capitalized costs, reported in note 3 and note 4, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

(2) Derecognitions, asset retirement obligations, transfer of exploration and evaluation assets, and other fair value adjustments.

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

Segmented Assets

	Mar 31 2021	Dec 31 2020
Exploration and Production		
North America	**$ 28,862**	$ 29,094
North Sea	**1,498**	1,624
Offshore Africa	**1,363**	1,407
Other	**110**	81
Oil Sands Mining and Upgrading	**41,725**	41,567
Midstream and Refining	**1,370**	1,301
Head office	**199**	202
	$ 75,127	$ 75,276

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated July 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 March 31, 2021:	
Interest coverage (times)	
Net earnings [(1)]	4.0x
Adjusted funds flow [(2)]	10.0x

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

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

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Corporate Information

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Aberdeen, Scotland

David. B. Whitehouse
Vice-President and Managing Director, International

Barry Duncan
Vice-President, Finance, International

Stock Listing

Toronto Stock Exchange
Trading Symbol - CNQ

New York Stock Exchange
Trading Symbol - CNQ

Registrar and Transfer Agent

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