Canadian Natural

THIRD QUARTER REPORT

NINE MONTHS ENDED SEPTEMBER 30, 2020 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2020 THIRD QUARTER RESULTS

Canadian Natural's President, Tim McKay, commented on the third quarter results stating "The resilience of our business model, as witnessed in our third quarter 2020 results, demonstrates Canadian Natural's competitive advantage as the strength of our long life low decline asset base allows the Company to effectively manage through commodity price cycles while preserving net asset value. Canadian Natural is focused on continuous improvement and is on track for the targeted operating cost savings in 2020 of approximately $745 million dollars. With a disciplined capital program in 2020 of approximately $2.7 billion, we have been able to maintain our production volumes, grow our dividend and keep a strong balance sheet.

In the third quarter, we increased liquids production from our North America Exploration and Production ("E&P") assets by approximately 20% from Q2/20 levels to 494,952 bbl/d and achieved record daily thermal in situ production in the quarter of 287,978 bbl/d, while achieving low thermal operating costs of $7.85/bbl (US$5.89/bbl). These results were achieved as we successfully executed on our curtailment optimization strategy while we conducted planned maintenance and turnaround activities in our Oil Sands Mining and Upgrading segment.

Environmental, Social and Governance ("ESG") performance remains a priority and investments in improving environmental performance and reducing our environmental footprint continue in the current pricing environment. We recently released our 2019 Report to Stakeholders, which highlights our commitment to ESG excellence and reducing our environmental footprint.

Subsequent to quarter end, the acquisition of Painted Pony Energy Ltd. ("Painted Pony") closed on October 6, 2020. With a significant amount of pre-built infrastructure, these high quality assets in the Townsend areas of Northeast British Columbia complement our already high quality natural gas asset base in Western Canada. The Company’s natural gas production, targeted at over 1.6 Bcf/d in the fourth quarter, and associated natural gas liquids is forecast to generate approximately $1.2 billion in annualized operating cash flow at current strip pricing."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "Our unique and diversified asset base allows us to generate significant free cash flow above our disciplined capital program and maintain our dividend payment level, unchanged through the commodity price cycle. In the third quarter, we generated approximately $1.74 billion in adjusted funds flow and approximately $467 million in free cash flow, after capital expenditures and dividend payments, reflecting the flexibility and strength of our long life low decline asset base.

The Company maintains a flexible and disciplined capital allocation strategy, with a focus on maintaining a strong and resilient financial position throughout the commodity price cycle. In the third quarter we allocated our free cash flow to the balance sheet, contributing to a significant reduction in net debt of approximately $1.1 billion. Including committed and undrawn credit facilities, cash balances and short-term investments, the Company had significant liquidity available at September 30, 2020 of approximately $4.2 billion.

Our effective and efficient operations along with our low cost structure drives our industry leading break-even of WTI US$30-$31 per barrel to cover sustaining capital and current dividend payment levels. Our low break-even maximizes netbacks, ultimately increasing free cash flow and creating value for our shareholders."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Sep 30 2020	Jun 30 2020	Sep 30 2019	Nine Months Ended Sep 30 2020	Sep 30 2019
Net earnings (loss)	**$ 408**	$ (310)	$ 1,027	**$ (1,184)**	$ 4,819
Per common share – basic	**$ 0.35**	$ (0.26)	$ 0.87	**$ (1.00)**	$ 4.04
– diluted	**$ 0.35**	$ (0.26)	$ 0.87	**$ (1.00)**	$ 4.03
Adjusted net earnings (loss) from operations (1)	**$ 135**	$ (772)	$ 1,229	**$ (932)**	$ 3,109
Per common share – basic	**$ 0.11**	$ (0.65)	$ 1.04	**$ (0.79)**	$ 2.61
– diluted	**$ 0.11**	$ (0.65)	$ 1.04	**$ (0.79)**	$ 2.60
Cash flows from (used in) operating activities	**$ 2,070**	$ (351)	$ 2,518	**$ 3,444**	$ 6,375
Adjusted funds flow (2)	**$ 1,740**	$ 415	$ 2,881	**$ 3,492**	$ 7,773
Per common share – basic	**$ 1.47**	$ 0.35	$ 2.43	**$ 2.96**	$ 6.51
– diluted	**$ 1.47**	$ 0.35	$ 2.43	**$ 2.96**	$ 6.50
Cash flows used in investing activities	**$ 643**	$ 693	$ 908	**$ 2,195**	$ 6,401
Net capital expenditures (3)	**$ 771**	$ 421	$ 963	**$ 2,030**	$ 6,065
Daily production, before royalties					
Natural gas (MMcf/d)	**1,362**	1,462	1,469	**1,421**	1,504
Crude oil and NGLs (bbl/d)	**884,342**	921,895	931,546	**914,859**	829,031
Equivalent production (BOE/d) (4)	**1,111,286**	1,165,487	1,176,361	**1,151,693**	1,079,641

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that 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 that 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 that 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.

- Net earnings of $408 million and adjusted net earnings of $135 million were realized in Q3/20, a significant improvement over Q2/20 levels. The increases in net earnings and adjusted net earnings are primarily a result of strong production volumes, continued reduction in operating cost levels and improved commodity prices in Q3/20.
- Cash flows from operating activities were $2,070 million in Q3/20, a significant increase over Q2/20 levels.
- Canadian Natural generated quarterly adjusted funds flow of $1,740 million in Q3/20, an increase of 319% over Q2/20 levels, driven by the Company's effective and efficient operations as well as higher commodity prices in the quarter.
- Canadian Natural generated approximately $467 million in free cash flow in Q3/20, after net capital expenditures of $771 million and dividend payments of $502 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 maintained a strong financial position in Q3/20 and reduced net debt by approximately $1.1 billion, from Q2/20 levels.
  - The Company had significant liquidity available at September 30, 2020 of approximately $4.2 billion, including committed and undrawn credit facilities, cash balances and short-term investments.

- The Company effectively executed on its curtailment optimization strategy by utilizing its high quality, flexible asset base to maximize production to offset the previously announced maintenance and turnaround activities in the Oil Sands Mining and Upgrading segment.
- In Q3/20, the Company achieved quarterly production volumes of 1,111,286 BOE/d, including liquids production of 884,342 bbl/d which decreased as expected 5% and 4% from Q3/19 and Q2/20 levels respectively. The decrease was due to the planned maintenance and turnaround activities in the Oil Sands Mining and Upgrading segment, primarily offset by strong thermal in situ production as a result of the Company's curtailment optimization strategy and improved commodity pricing in Q3/20.
- Canadian Natural's North America Exploration and Production ("E&P") liquids production averaged 494,952 bbl/d in Q3/20, a 10% increase from Q3/19 levels and a 20% increase from Q2/20 levels. The increase over both periods was due to the Company's curtailment optimization strategy, primarily as a result of increased thermal in situ production at Kirby North and Jackfish as well as the optimization of steam cycles at Primrose.
  - Canadian Natural's continued focus on delivering effective and efficient operations and cost control across its entire asset base was also demonstrated as the Company's North American E&P liquids, including thermal in situ operations, achieved operating costs of $9.80/bbl (US$7.36/bbl) in Q3/20, a decrease of 17% from Q3/19 levels and a decrease of 16% from Q2/20 levels.
- Canadian Natural's thermal in situ assets achieved record daily production levels in Q3/20, averaging 287,978 bbl/d, an increase of 40% and 35% over Q3/19 and Q2/20 levels respectively. The record daily production levels in Q3/20 was as a result of the Company leveraging the flexibility of its thermal in situ assets to maximize production during planned maintenance and turnaround activities in the Company's Oil Sands Mining and Upgrading segment as a part of the Company's curtailment optimization strategy.
  - Thermal in situ achieved low operating costs in Q3/20, averaging $7.85/bbl (US$5.89/bbl), a decrease of 20% and 23% from Q3/19 and Q2/20 levels respectively. The decrease in unit operating costs was primarily due to higher production volumes and continued focus on effective and efficient operations.
  - Kirby North had strong quarterly production of approximately 42,400 bbl/d in Q3/20, and has been producing above its nameplate capacity of 40,000 bbl/d since achieving full ramp-up in June 2020.
  - At Jackfish, the Company achieved quarterly production of 122,346 bbl/d in Q3/20, a record quarterly production level since acquiring the asset in June 2019.
- The Company's world class Oil Sands Mining and Upgrading assets averaged 350,633 bbl/d of SCO production in Q3/20, decreasing by 19% and 24% from Q3/19 and Q2/20 levels respectively, primarily due to planned maintenance and turnaround activities at both the Athabasca Oil Sands Project ("AOSP") and Horizon.
  - Operating costs from the Company's Oil Sands Mining and Upgrading assets averaged $23.81/bbl (US$17.88/bbl) of SCO in Q3/20 and remain industry leading, driven by the Company's continued focus on cost control.
- A strategic advantage of Canadian Natural is its flexible portfolio of assets, allowing the Company to allocate capital to its highest return projects, maximizing value for the Company's shareholders. As a result of improved natural gas prices, Canadian Natural has strategically reallocated a portion of its capital program to its high value, liquids rich natural gas assets at Septimus and the assets recently acquired as part of the Painted Pony Energy Ltd. ("Painted Pony") acquisition. As one of the largest natural gas producers in Canada, the Company's natural gas assets provide significant value. The Company's natural gas production, targeted at over 1.6 Bcf/d in Q4/20, and associated natural gas liquids is forecast to generate approximately $1.2 billion in annualized operating cash flow at current strip pricing.
  - Canadian Natural drilled seven wells at Septimus in Q3/20, with one additional well drilled subsequent to quarter end. All eight wells are expected to be on production in Q4/20 at a targeted rate of 41 MMcf/d and 2,500 bbl/d of NGLs, for a cost of approximately $5,000 per flowing BOE.
  - Subsequent to quarter end, in October 2020, Canadian Natural initiated drilling the first of seven wells on the high quality Montney lands acquired with the Painted Pony acquisition. These wells are expected to come on production in the first half of 2021 at a targeted initial rate of 54 MMcf/d and 440 bbl/d of NGLs.
- Canadian Natural targets to release its 2021 capital and operational budget in December 2020.

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 79% of the Company's total liquids production in Q3/20, the majority of which is zero decline high value SCO production from the Company's world class Oil Sands Mining and Upgrading assets. The remaining balance of long life low decline production comes from Canadian Natural's top tier thermal in situ oil sands operations and the Company's Pelican Lake heavy crude oil assets. The combination of long life low decline, low reserves replacement cost, and effective and efficient operations, results in substantial and sustainable adjusted funds flow throughout the commodity price cycle.

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

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

Drilling Activity	Nine Months Ended Sep 30			
	2020		2019	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**43**	**37**	80	74
Natural gas	**25**	**21**	21	15
Dry	**—**	**—**	3	3
Subtotal	**68**	**58**	104	92
Stratigraphic test / service wells	**426**	**372**	411	358
Total	**494**	**430**	515	450
Success rate (excluding stratigraphic test / service wells)		**100%**		97%

- The Company's total crude oil and natural gas drilling program of 58 net wells for the nine months ended September 30, 2020, excluding stratigraphic/service wells, represents a decrease of 34 net wells from the same period in 2019.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Crude oil and NGLs production (bbl/d)	**206,974**	200,699	244,267	**212,064**	234,944
Net wells targeting crude oil	**—**	2	33	**30**	70
Net successful wells drilled	**—**	2	33	**30**	68
Success rate	**—**	100%	100%	**100%**	97%

- Canadian Natural's North America E&P crude oil and NGL production volumes, excluding the Company's thermal in situ operations, averaged 206,974 bbl/d, a decrease of 15% from Q3/19 levels and an increase of 3% from Q2/20 levels. The decrease from Q3/19 reflects natural declines and limited investment, while the increase over

Q2/20 reflects the reinstatement of production as a result of the Company curtailing production in Q2/20 due to low commodity prices.

- Primary heavy crude oil production averaged 70,982 bbl/d in Q3/20, a decrease of 19% from Q3/19 levels and an increase of 13% from Q2/20 levels. The decrease in production relative to Q3/19 was due to natural field declines and low levels of field activity due to the Government of Alberta's curtailment rules. The increase from Q2/20 was due to the reinstatement of previously shut-in production as a result of improved commodity prices in Q3/20.
  - Operating costs in the Company's primary heavy crude oil operations in Q3/20 averaged $15.96/bbl (US$11.98/bbl), a 7% decrease from Q3/19 levels and an 11% decrease from Q2/20 levels as the Company focused on cost control.
- Pelican Lake production averaged 56,392 bbl/d in Q3/20, a decrease of 6% from Q3/19 levels and a slight increase from Q2/20 levels. The decrease from Q3/19 levels reflects the field's low natural decline rate, while the slight increase from Q2/20 levels was primarily due to reduced well servicing activity in Q2/20 due to low commodity prices.
  - The Company continues to demonstrate effective and efficient operations as Q3/20 operating costs at Pelican Lake averaged $5.76/bbl (US$4.32/bbl), a decrease of 6% from Q3/19 levels and a decrease of 9% from Q2/20 levels, reflecting the Company's continued focus on cost control.
- North American light crude oil and NGL production averaged 79,600 bbl/d in Q3/20, a decrease of 17% and 3% from Q3/19 and Q2/20 levels respectively. The decrease from Q3/19 was a result of natural field declines. The decrease from Q2/20 was primarily a result of natural field declines and deferral of maintenance activities into Q3/20 as a result of COVID-19.
  - Operating costs in the Company's North America light crude oil and NGL areas averaged $14.13/bbl (US$10.61/bbl) in Q3/20, a decrease of 6% and 2% from Q3/19 and Q2/20 levels respectively as a result of the Company's continued focus on cost control.

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Bitumen production (bbl/d)	**287,978**	212,807	206,395	**243,193**	137,124
Net wells targeting bitumen	**—**	—	—	**6**	—
Net successful wells drilled	**—**	—	—	**6**	—
Success rate	**—**	—	—	**100%**	—

- Canadian Natural's thermal in situ assets achieved record daily production levels in Q3/20, averaging 287,978 bbl/d, an increase of 40% and 35% over Q3/19 and Q2/20 levels respectively. The record daily production levels in Q3/20 was as a result of the Company leveraging the flexibility of its thermal in situ assets to maximize production during planned maintenance and turnaround activities in the Company's Oil Sands Mining and Upgrading segment as a part of the Company's curtailment optimization strategy.
  - Thermal in situ achieved low operating costs in Q3/20, averaging $7.85/bbl (US$5.89/bbl), a decrease of 20% and 23% from Q3/19 and Q2/20 levels respectively. The decrease in unit operating costs was primarily due to higher production volumes and continued focus on effective and efficient operations.
  - Kirby North had strong quarterly production of approximately 42,400 bbl/d in Q3/20, and has been producing above its nameplate capacity of 40,000 bbl/d since achieving full ramp-up in June 2020.
  - At Jackfish, the Company achieved quarterly production of 122,346 bbl/d in Q3/20, a record quarterly production level since acquiring the asset in June 2019.
- The Company continues to see positive results from its targeted two year solvent enhanced oil recovery technology pilot at Kirby South, with increased bitumen production, a SOR reduction of up to 50%, Greenhouse Gas ("GHG") intensity reduction of up to 50% and high solvent recovery. The Company will continue to monitor the solvent recovery of the pilot over the next year. This technology has the potential for application throughout the Company's extensive thermal in situ asset base. At Primrose, in the steam flood area, the Company is targeting to commence a second solvent pilot in the latter half of 2021.

North America Natural Gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Natural gas production (MMcf/d)	**1,340**	1,431	1,425	**1,393**	1,454
Net wells targeting natural gas	**9**	1	5	**21**	16
Net successful wells drilled	**9**	1	5	**21**	15
Success rate	**100%**	100%	100%	**100%**	94%

- North America natural gas production averaged 1,340 MMcf/d in Q3/20, a decrease of 6% from both Q3/19 and Q2/20 levels. The decrease in production was primarily as a result of natural field declines and planned maintenance and turnaround activities undertaken in the third quarter of 2020, partially offset by natural gas volumes added through low cost opportunities identified by the Company in May 2020.
  - Through additional cost efficiencies, the Company now targets to bring on these highly economic incremental volumes for less than $2,000 per flowing BOE, approximately $1,000 per flowing BOE lower than previously estimated. Current production from these additional gas volumes is 58 MMcf/d and the Company is on track to achieve annualized production of approximately 35 MMcf/d from these opportunities.
- North America natural gas operating costs were strong in Q3/20, averaging $1.14/Mcf, an increase of 7% and 3% from Q3/19 and Q2/20 levels respectively. The increase in operating costs relative to prior periods reflects lower production volumes in Q3/20. As a result of the Company's strategy to own and control its infrastructure and its continued focus on cost control, natural gas operating costs for the first nine months of 2020 were comparable to the first nine months of 2019.
- Operating costs at Septimus remained strong, averaging $0.28/Mcfe in Q3/20, a 10% decrease from Q2/20 levels.
- A strategic advantage of Canadian Natural is its flexible portfolio of assets, allowing the Company to allocate capital to its highest return projects, maximizing value for the Company's shareholders. As a result of improved natural gas prices, Canadian Natural has strategically reallocated a portion of its capital program to its high value, liquids rich natural gas assets at Septimus and the assets recently acquired as part of the Painted Pony acquisition. The Company's natural gas production, targeted at over 1.6 Bcf/d in Q4/20, and associated natural gas liquids is forecast to generate approximately $1.2 billion in annualized operating cash flow at current strip pricing.
  - Canadian Natural drilled seven wells at Septimus in Q3/20, with one additional well drilled subsequent to quarter end. All eight wells are expected to be on production in Q4/20 at a targeted rate of 41 MMcf/d and 2,500 bbl/d of NGLs, for a cost of approximately $5,000 per flowing BOE.
  - Subsequent to quarter end, in October 2020, Canadian Natural initiated drilling the first of seven wells on the high quality Montney lands acquired with the Painted Pony acquisition. These wells are expected to come on production in the first half of 2021 at a targeted initial rate of 54 MMcf/d and 440 bbl/d of NGLs.
- In Q3/20, Canadian Natural used the equivalent of approximately 49% of corporate annual natural gas production within its operations, providing a natural hedge from Western Canadian natural gas prices. Approximately 34% was exported to other North American markets and sold internationally, while the remaining 17% was exposed to AECO/Station 2 pricing.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Crude oil production (bbl/d)					
North Sea	**21,220**	26,627	27,454	**25,186**	26,927
Offshore Africa	**17,537**	17,444	21,227	**16,977**	22,341
Natural gas production (MMcf/d)					
North Sea	**5**	15	20	**14**	24
Offshore Africa	**17**	16	24	**14**	26
Net wells targeting crude oil	**—**	—	3.0	**1.0**	5.5
Net successful wells drilled	**—**	—	3.0	**1.0**	5.5
Success rate	**—**	—	100%	**100%**	100%

- International E&P crude oil production volumes averaged 38,757 bbl/d in Q3/20, a decrease of 20% and 12% from Q3/19 and Q2/20 levels respectively.
  - In the North Sea, crude oil production volumes averaged 21,220 bbl/d in Q3/20, a decrease of 23% and 20% from Q3/19 and Q2/20 levels respectively. The decrease in production in Q3/20 was primarily a result of planned maintenance and turnaround activities, the permanent cessation of production from the Banff and Kyle fields and natural field declines.
    - Crude oil operating costs in the North Sea increased by 13% and 48% from Q3/19 and Q2/20 levels respectively, averaging $42.10/bbl (US$31.61/bbl) in Q3/20. The increase in operating costs from the comparable periods primarily reflects lower production volumes on a relatively fixed cost base, together with the timing of liftings from various fields that have different cost structures.
  - Offshore Africa crude oil production volumes averaged 17,537 bbl/d in Q3/20, a decrease of 17% from Q3/19 levels and comparable to Q2/20 levels. The decrease in production from Q3/19 levels was primarily due to natural field declines.
    - Offshore Africa crude oil operating costs averaged $16.41/bbl (US$12.32/bbl) in Q3/20, an increase of 48% and 55% from Q3/19 and Q2/20 levels respectively. The increase in operating costs from the comparable periods was primarily due to the timing of liftings from various fields that have different cost structures.
  - Subsequent to quarter end, as announced on October 28, 2020, the operator of the South Africa block 11B/12B has made a significant gas condensate discovery on the Luiperd prospect. This discovery follows the previously announced Brulpadda discovery in 2019. The Luiperd exploratory well encountered 73 meters of net gas condensate pay, and is currently being tested with deliverability results targeted by year end 2020. Canadian Natural has a 20% working interest and expects the costs for this well to be fully carried pursuant to Farm-Out Agreements.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Synthetic crude oil production (bbl/d) (1) (2)	**350,633**	464,318	432,203	**417,439**	407,695

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

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

- The Company's world class Oil Sands Mining and Upgrading assets averaged 350,633 bbl/d of SCO production in Q3/20, decreasing by 19% and 24% from Q3/19 and Q2/20 levels respectively, primarily due to planned maintenance and turnaround activities at both AOSP and Horizon.

- Operating costs from the Company's Oil Sands Mining and Upgrading assets remain industry leading, driven by the Company's continued focus on cost control. In Q3/20, operating costs averaged $23.81/bbl (US$17.88/bbl) of SCO, an increase of 19% and 34% from Q3/19 and Q2/20 levels respectively. The increase in operating costs in Q3/20 includes the cost of planned maintenance and turnaround activities and impact of lower production volumes.

- During the maintenance period at the Scotford Upgrader ("Scotford"), the front end capacity was expanded to approximately 320,000 bbl/d from the previous capacity of 300,000 bbl/d. This additional capacity at AOSP is targeted to increase margins, further maximizing value of the Company's Oil Sands Mining and Upgrading assets.
  - At the non-operated Scotford Upgrader, maintenance activities were completed 13 days later than originally planned. As well, upon start-up of Scotford, additional work was identified resulting in the plant running at reduced gross rates until October 16, 2020. As a result, gross production at AOSP averaged approximately 267,000 bbl/d in October 2020.
  - In late October, Albian ran at gross rates of approximately 345,000 bbl/d of bitumen, and Scotford processed rates at approximately 323,000 bbl/d. As a result of mandatory curtailments in November 2020, AOSP will target to resume production near these full expanded capacity rates in December 2020.
  - Maintenance activities at the Albian mines were aligned with the timing of maintenance and turnaround activities at Scotford.
- Planned maintenance and turnaround activities at Horizon, which commenced in late September, were successfully completed subsequent to quarter end. Upon start-up, a small bore pipe failed, which resulted in the plant running initially at reduced rates. The cost of the repair was minor and is included within the Horizon maintenance budget. Production at Horizon in October 2020 averaged approximately 134,000 bbl/d of SCO, and is currently at approximately 260,000 bbl/d.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 40.94**	$ 27.85	$ 56.45	**$ 38.30**	$ 57.06
WCS heavy differential as a percentage of WTI (%) (2)	**22%**	41%	22%	**36%**	21%
SCO price (US$/bbl)	**$ 38.61**	$ 23.28	$ 56.87	**$ 35.11**	$ 56.36
Condensate benchmark pricing (US$/bbl)	**$ 37.55**	$ 22.19	$ 52.00	**$ 35.10**	$ 52.79
Average realized pricing before risk management (C$/bbl) (3)	**$ 40.14**	$ 18.97	$ 55.19	**$ 28.91**	$ 57.49
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.03**	$ 1.81	$ 0.99	**$ 1.96**	$ 1.31
Average realized pricing before risk management (C$/Mcf)	**$ 2.31**	$ 2.03	$ 1.64	**$ 2.19**	$ 2.24

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

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

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

- Canadian Natural has a balanced and diverse product mix with a history of strong expertise in marketing its products.
- Commodity prices, including WTI, have improved and stabilized relative to the volatility experienced in the first half of 2020 and Western Canadian Select ("WCS") differentials have tightened as a result of returning demand combined with reduced activity in the Western Canadian Sedimentary Basin ("WCSB"), production declines and price-related curtailments and shut-ins.

- Natural gas prices have also improved in Q3/20, with AECO averaging $2.03/GJ, an increase of 105% and 12% from the Q3/19 and Q2/20 averages respectively. The increase in natural gas prices from the comparable periods primarily reflects lower WCSB production.
- Canadian Natural has storage at major hubs in Edmonton and Hardisty, which allows the Company to adjust monthly sales and manage pipeline logistical constraints and production fluctuations, as well as pricing differences from month to month.
- Market egress will continue to improve in the mid-term as construction is progressing on the Trans Mountain Expansion ("TMX") and Keystone XL projects, on which Canadian Natural has 94,000 bbl/d and 200,000 bbl/d respectively of committed capacity. Combining these two pipeline projects and including Enbridge Line 3 replacement, Western Canadian egress is targeted to increase by approximately 1.8 MMbbl/d in the mid-term.
    - TMX construction continues to progress and is targeted to be on stream in late 2022.
    - Keystone XL construction continues to progress in both Canada and the United States.
    - 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 available in 2021.
- The North West Redwater Refinery reached commercial operations on June 1, 2020 and continues to ramp-up to its targeted processing capacity of approximately 80,000 bbl/d of diluted bitumen, which will improve heavy oil demand in western Canada, effectively increasing egress out of the WCSB. For more details, please contact the North West Redwater Partnership.
- Subsequent to quarter end, the Government of Alberta has suspended the mandatory curtailment production limits as of December 2020 and will only issue curtailment orders in 2021 when deemed necessary.

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 production of 1,111,286 BOE/d in Q3/20, with approximately 98% of total production located in G7 countries.
- Canadian Natural generated quarterly adjusted funds flow of $1,740 million in Q3/20, an increase of 319% over Q2/20 levels, driven by the Company's effective and efficient operations as well as higher commodity prices in the quarter.
- Canadian Natural generated approximately $467 million in free cash flow, after net capital expenditures and dividend payments in Q3/20 reflecting the strength of the Company's effective and efficient operations and its high quality, long life low decline asset base.
- Returns to shareholders totaled $502 million in Q3/20 by way of dividends paid on July 1, 2020. As previously announced on March 18, 2020, the Company's share repurchase program has been suspended and the Board of Directors made the decision to not renew the Company's NCIB program, which expired in May 2020.
- Canadian Natural maintained a strong financial position and reduced net debt in Q3/20 from Q2/20 levels by approximately $1.1 billion. The Company has significant liquidity available at September 30, 2020 of approximately $4.2 billion, including committed and undrawn credit facilities, cash balances and short-term investments.
    - The Company repaid $1.0 billion in medium term notes that matured in August 2020.
    - The Company has approximately $5.5 billion of availability under its United States (US$1.9 billion) and Canadian (C$3.0 billion) base shelf prospectuses, which expire August 2021, allowing the Company to offer these securities for sale from time to time.
    - Debt to book capitalization and debt to adjusted EBITDA remained strong at 40.3% and 3.4x respectively.
- Canadian Natural continues to maintain strong investment grade credit ratings. The Company has a high degree of communication with credit rating agencies to ensure they understand the robust and sustainable nature of the Company's assets.

- Canadian Natural's business is unique, robust and sustainable. The strength of the Company's assets are shown in its ability to generate significant and sustainable free cash flow over the long term, combined with its low cost structure and industry leading corporate break-even price of WTI US$30-31 per barrel.
- The Company's 2020 capital program is on target to be approximately $2.7 billion, before acquisitions, while maintaining base production near 2019 levels.
- Subsequent to quarter end, the Company declared a quarterly dividend of $0.425 per share, payable on January 5, 2021.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE ("ESG") HIGHLIGHTS

Canada and Canadian Natural are well positioned to deliver responsibly produced energy the world needs through leading ESG performance.

In September 2020, Canadian Natural published its 2019 Stewardship Report to Stakeholders, which is available on the Company's website at https://www.cnrl.com/report-to-stakeholders. The report displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing its environmental footprint. Canadian Natural outlined its pathway to lower carbon emissions and its journey to achieve its aspirational goal of net zero GHG emissions in the oil sands. Highlights from the Company's 2019 report are as follows:

- Achieved record low corporate total recordable injury frequency ("TRIF") in 2019, with a TRIF of 0.28 in 2019 compared to 0.57 in 2015. The Company's TRIF is down 51% since 2015, while man-hours have increased over this time period.
- 3 of the 8 independent directors of the Board are female, achieving the Company's Board gender diversity target of no less than 30% of independent directors.
- Awarded over $550 million in contracts to more than 150 Indigenous businesses in 2019.
- Canadian Natural has invested over $3.7 billion in research and development over the last decade and continues to invest in technology to unlock reserves, become more effective and efficient and reduce the Company's environmental footprint. Canadian Natural's culture of continuous improvement leverages the use of technology and innovation to drive sustainable operations and long-term value for shareholders. In 2019, the Company invested $77.4 million in GHG research, technologies and projects as part of its research and development budget.
- Canadian Natural's corporate GHG emissions intensity has decreased by 16% from 2015 to 2019, a material reduction in emissions intensity.
- Canadian Natural is leading the crude oil and natural gas industry in Carbon Capture and Storage ("CCS") and sequestration initiatives and is one of the largest owners of carbon capture capacity in the oil and natural gas sector globally. 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 vehicles off the road per year.
  - At the Company's 70% owned Quest CCS facility located at Scotford, the facility captures and stores approximately 1.1 million tonnes of CO_2 per year and recently reached the milestone of 5 million tonnes of stored carbon dioxide. Quest highlights the crude oil and natural gas industry's leadership in leveraging technology and innovation and the strength of industry and government collaboration to continuously improve operational and environmental performance.
  - Canadian Natural has a 50% working interest in the North West Redwater Refinery, which combines gasification technology with an integrated carbon capture and storage program, capturing approximately 1.2 million tonnes of CO_2 per year and eliminating approximately 70% of the refinery's total carbon footprint. This project successfully reached commercial operations on June 1, 2020.
  - The Company has approximately 400,000 tonnes of CO_2 capture capacity per year for sequestration at Horizon by injecting CO_2 into its tailings ponds. This improves the Company's operating costs as a result of smaller tailings footprint and more efficient use of natural gas, as well as reduces GHG emissions and accelerates reclamation.
- The Company reduced its GHG emissions intensity in its Oil Sands Mining and Upgrading and thermal in situ segments by 36% from 2016 to 2019.

- The Company reduced methane emissions in its North American E&P segment by 15% from 2016 to 2019.
- Oil Sands Mining and Upgrading fresh river water use intensity decreased by 68% from 2012 to 2019.
- Thermal in situ fresh water use intensity decreased by 61% from 2012 to 2019.
- In 2019, Canadian Natural abandoned 2,035 inactive wells in its North America E&P segment, a corporate record, and an increase of 57% over 2018 levels. The Company also submitted 912 reclamation certificates in 2019.
- The Company has reclaimed more than 7,600 hectares of land since 2015 in its North America E&P segment, equivalent to approximately 9,400 Canadian football fields. In 2019 alone, the Company reclaimed 2,160 hectares of land, a 56% increase from 2018.
- Commercial engineering of the In Pit Extraction Process ("IPEP") at Horizon continues, although the Company has temporarily delayed the field pilot in order to limit staffing levels to personnel who are critical to maintaining safe, reliable operations in response to COVID-19 guidelines. Canadian Natural is pleased with the results from the initial testing phase of the pilot, which showed excellent recovery rates and evidence of stackable tailings. The IPEP pilot will determine the feasibility of producing stackable dry tailings on a commercial basis. The project has the potential to reduce the Company's bitumen production GHG emissions by approximately 40% and lower the Company's environmental footprint by decreasing the handling of material, reducing the distance driven by its fleet of haul trucks, decreasing the size and need for tailings ponds and accelerating site reclamation. In addition, this process has the potential to reduce capital and operating costs.

ADVISORY

Special Note Regarding non-GAAP Financial Measures

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

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

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

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

Operating cash flow is a forward looking supplementary measure that represents the Company’s currently forecasted cash flow from operating activities for the stated forecast period for a particular product or group of products or segment, excluding the impact of administration expense, interest, foreign exchange, and taxes. The Company considers operating cash flow by product or segment a key measure in evaluating the contribution of a product to the Company’s cash flow from operating activities.

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

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

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

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

This Page Left Intentionally Blank

MANAGEMENT’S DISCUSSION AND ANALYSIS

ADVISORY

Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses and other guidance 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 project, 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, and the development and deployment of technology and technological innovations also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

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

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of effects of the novel coronavirus ("COVID-19") pandemic and the actions of the Organization of the Petroleum Exporting Countries ("OPEC") and non-OPEC countries) 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 and non-OPEC countries taken in response to COVID-19 or otherwise; fluctuations in currency and interest rates; assumptions on which the Company’s current guidance is 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; 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 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 (used in) 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 (used in) operating activities, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP financial measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three and nine months ended September 30, 2020 and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2019. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2020 and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

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

The following discussion and analysis refers primarily to the Company's financial results for the three and nine months ended September 30, 2020 in relation to the comparable periods in 2019 and the second quarter of 2020. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2019, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Information on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated November 4, 2020.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Sep 30 2020	Jun 30 2020	Sep 30 2019	Nine Months Ended Sep 30 2020	Sep 30 2019
Product sales [1]	**$ 4,676**	$ 2,944	$ 6,587	**$ 12,272**	$ 18,059
Crude oil and NGLs	**$ 4,202**	$ 2,462	$ 6,324	**$ 10,987**	$ 17,003
Natural gas	**$ 338**	$ 307	$ 257	**$ 982**	$ 1,037
Net earnings (loss)	**$ 408**	$ (310)	$ 1,027	**$ (1,184)**	$ 4,819
Per common share – basic	**$ 0.35**	$ (0.26)	$ 0.87	**$ (1.00)**	$ 4.04
– diluted	**$ 0.35**	$ (0.26)	$ 0.87	**$ (1.00)**	$ 4.03
Adjusted net earnings (loss) from operations [2]	**$ 135**	$ (772)	$ 1,229	**$ (932)**	$ 3,109
Per common share – basic	**$ 0.11**	$ (0.65)	$ 1.04	**$ (0.79)**	$ 2.61
– diluted	**$ 0.11**	$ (0.65)	$ 1.04	**$ (0.79)**	$ 2.60
Cash flows from (used in) operating activities	**$ 2,070**	$ (351)	$ 2,518	**$ 3,444**	$ 6,375
Adjusted funds flow [3]	**$ 1,740**	$ 415	$ 2,881	**$ 3,492**	$ 7,773
Per common share – basic	**$ 1.47**	$ 0.35	$ 2.43	**$ 2.96**	$ 6.51
– diluted	**$ 1.47**	$ 0.35	$ 2.43	**$ 2.96**	$ 6.50
Cash flows used in investing activities	**$ 643**	$ 693	$ 908	**$ 2,195**	$ 6,401
Net capital expenditures [4]	**$ 771**	$ 421	$ 963	**$ 2,030**	$ 6,065

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

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

(3) Adjusted funds flow is a non-GAAP financial measure that represents cash flows from (used in) operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure 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 (used in) 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, investment in other long-term assets, share consideration in business combinations and abandonment expenditures. The Company considers net capital expenditures a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the "Net Capital Expenditures" section of this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.

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

($ millions)	Three Months Ended **Sep 30 2020**	Three Months Ended Jun 30 2020	Three Months Ended Sep 30 2019	Nine Months Ended **Sep 30 2020**	Nine Months Ended Sep 30 2019
Net earnings (loss)	***$ 408***	*$ (310)*	*$ 1,027*	***$ (1,184)***	*$ 4,819*
Share-based compensation, net of tax [(1)]	***(5)***	*23*	*7*	***(203)***	*62*
Unrealized risk management (gain) loss, net of tax [(2)]	***(1)***	*1*	*(2)*	***(15)***	*(2)*
Unrealized foreign exchange (gain) loss, net of tax [(3)]	***(270)***	*(433)*	*129*	***418***	*(323)*
Realized foreign exchange gain on settlement of cross currency swaps [(4)]	**—**	—	—	***(166)***	—
Loss (gain) from investments, net of tax [(5)] [(6)]	***3***	*(53)*	*68*	***218***	*171*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities [(7)]	**—**	—	—	**—**	*(1,618)*
Adjusted net earnings (loss) from operations	***$ 135***	*$ (772)*	*$ 1,229*	***$ (932)***	*$ 3,109*

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plans. The Company's employee stock option plan provides for a cash payment option. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met. Accordingly, the fair value of the outstanding vested options is recorded 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 recorded at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings (loss). The amounts ultimately realized may be materially different than those amounts reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil, natural gas and foreign exchange.

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

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

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

(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 measured each period with changes in fair value recognized in net earnings (loss).

(7) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to the underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million.

Adjusted Funds Flow, as Reconciled to Cash Flows from (used in) Operating Activities

($ millions)	Three Months Ended **Sep 30 2020**	Three Months Ended Jun 30 2020	Three Months Ended Sep 30 2019	Nine Months Ended **Sep 30 2020**	Nine Months Ended Sep 30 2019
Cash flows from (used in) operating activities	***$ 2,070***	*$ (351)*	*$ 2,518*	***$ 3,444***	*$ 6,375*
Net change in non-cash working capital	***(372)***	*739*	*299*	***(228)***	*1,085*
Abandonment expenditures [(1)]	***68***	*40*	*63*	***197***	*212*
Other [(2)]	***(26)***	*(13)*	*1*	***79***	*101*
Adjusted funds flow	***$ 1,740***	*$ 415*	*$ 2,881*	***$ 3,492***	*$ 7,773*

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

(2) Movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

SUMMARY OF FINANCIAL HIGHLIGHTS

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

The net loss for the nine months ended September 30, 2020 was $1,184 million compared with net earnings of $4,819 million for the nine months ended September 30, 2019. The net loss for the nine months ended September 30, 2020 included net after-tax expenses of $252 million compared with net after-tax income of $1,710 million for the nine months ended September 30, 2019 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, foreign exchange gain on the settlement of the cross currency swaps, loss from investments, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, the adjusted net loss from operations for the nine months ended September 30, 2020 was $932 million compared with adjusted net earnings from operations of $3,109 million for the nine months ended September 30, 2019.

Net earnings for the third quarter of 2020 was $408 million compared with net earnings of $1,027 million for the third quarter of 2019 and a net loss of $310 million for the second quarter of 2020. Net earnings for the third quarter of 2020 included net after-tax income of $273 million compared with net after-tax expenses of $202 million for the third quarter of 2019 and net after-tax income of $462 million for the second quarter of 2020 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, and loss (gain) from investments. Excluding these items, adjusted net earnings from operations for the third quarter of 2020 was $135 million compared with adjusted net earnings from operations of $1,229 million for the third quarter of 2019 and an adjusted net loss from operations of $772 million for the second quarter of 2020.

The net loss and the adjusted net loss from operations for the nine months ended September 30, 2020 compared with net earnings and adjusted net earnings from operations for the nine months ended September 30, 2019 primarily reflected:

- lower crude oil and NGLs netbacks in the Exploration and Production segments; and
- lower natural gas sales volumes in the Exploration and Production segments;

partially offset by:

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

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

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

partially offset by:

- higher crude oil and NGLs sales volumes in the Exploration and Production segments; and
- higher natural gas netbacks in the Exploration and Production segments.

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

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

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment; and
- higher SCO production costs in the Oil Sands Mining and Upgrading segment.

The impacts of share-based compensation, risk management activities, fluctuations in foreign exchange rates and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities also contributed to the movements in net earnings (loss) from the comparable periods. These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows from (used in) Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the nine months ended September 30, 2020 were $3,444 million compared with $6,375 million for the nine months ended September 30, 2019. Cash flows from operating activities for the third quarter of 2020 were $2,070 million compared with cash flows from operating activities of $2,518 million for the third quarter of 2019 and cash flows used in operating activities of $351 million for the second quarter of 2020. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted relating to the fluctuations in net earnings (loss) and adjusted net earnings (loss) from operations (excluding the effects of depletion, depreciation and amortization and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the nine months ended September 30, 2020 was $3,492 million compared with $7,773 million for the nine months ended September 30, 2019. Adjusted funds flow for the third quarter of 2020 was $1,740 million compared with $2,881 million for the third quarter of 2019 and $415 million for the second 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 (used in) operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

Production Volumes

Total production before royalties for the third quarter of 2020 decreased 6% to 1,111,286 BOE/d from 1,176,361 BOE/d for the third quarter of 2019 and decreased 5% from 1,165,487 BOE/d for the second 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.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

The following is a summary of the Company's quarterly financial results for the eight most recently completed quarters:

($ millions, except per common share amounts)	**Sep 30 2020**	Jun 30 2020	Mar 31 2020	Dec 31 2019
Product sales [1]	**$ 4,676**	$ 2,944	$ 4,652	$ 6,335
Crude oil and NGLs	**$ 4,202**	$ 2,462	$ 4,323	$ 5,947
Natural gas	**$ 338**	$ 307	$ 337	$ 382
Net earnings (loss)	**$ 408**	$ (310)	$ (1,282)	$ 597
Net earnings (loss) per common share				
– basic	**$ 0.35**	$ (0.26)	$ (1.08)	$ 0.50
– diluted	**$ 0.35**	$ (0.26)	$ (1.08)	$ 0.50
($ millions, except per common share amounts)	Sep 30 2019	Jun 30 2019	Mar 31 2019	Dec 31 2018
Product sales [1]	$ 6,587	$ 5,931	$ 5,541	$ 3,831
Crude oil and NGLs	$ 6,324	$ 5,597	$ 5,082	$ 3,327
Natural gas	$ 257	$ 324	$ 456	$ 504
Net earnings (loss)	$ 1,027	$ 2,831	$ 961	$ (776)
Net earnings (loss) per common share				
– basic	$ 0.87	$ 2.37	$ 0.80	$ (0.64)
– diluted	$ 0.87	$ 2.36	$ 0.80	$ (0.64)

(1) Further details related to product sales for the three months ended September 30, 2020 and 2019 are disclosed in note 18 to the Company's unaudited interim consolidated financial statements.

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

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from OPEC and its impact on world supply; the impact of geopolitical and market uncertainties, including those due to COVID-19 and in connection with governmental responses to COVID-19, on worldwide benchmark pricing; the impact of shale oil production in North America; the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin"); the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa and the impact of production curtailments mandated by the Government of Alberta that came into effect January 1, 2019.
- **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 Kirby South and Kirby North, 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, voluntarily curtailed production in late 2018 due to low commodity prices in North America and production curtailments mandated by the Government of Alberta that came into effect January 1, 2019 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, fluctuating capacity at the Pine River processing facility, shut-in production due to third-party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production volumes, the impact of seasonal 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, maintenance activities in the International segments and the impact of the adoption of IFRS 16 on January 1, 2019.
- **Depletion, depreciation and amortization** – 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, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment and the impact of the adoption of IFRS 16 on January 1, 2019.
- **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 the adoption of IFRS 16 on January 1, 2019, fluctuating long-term debt levels, and the impact of movements in benchmark interest rates on outstanding floating rate long-term debt.
- **Foreign exchange rates** – 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.
- **Gains on acquisition and disposition and gains/losses on investments** – Fluctuations due to the recognition of the acquisition and disposition of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss on the Company's interest in NWRP.
- **Income tax expense** – Fluctuations due to statutory tax rate and other legislative changes substantively enacted in the various periods.

BUSINESS ENVIRONMENT

Global benchmark crude oil prices decreased significantly in the first half of 2020 due to the erosion of global demand, reflecting the severity of COVID-19 and related economic conditions. In response to the collapse of oil prices in April 2020, OPEC and Russia agreed to cut 9.7 MMbbl/d of production through July 2020. As the global economy improved in the third quarter of 2020, OPEC and Russia agreed to ease these production cuts to 7.7 MMbbl/d through to December 2020. Pricing improved in the third quarter of 2020 with WTI benchmark pricing averaging US$40.94 per bbl and the WCS Heavy Differential averaging US$9.06 per bbl.

Production Flexibility and Cost Control

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

The Company continued to prioritize the optimization of higher value light crude oil, NGLs and SCO, representing approximately 43% of total corporate BOE production volumes in the third quarter of 2020. Optimization of production volumes continues to be a key focus of the Company at current commodity price levels.

Production costs in the third quarter of 2020 also reflected the impact of measures to promote social distancing related to COVID-19 at the Oil Sands Mining and Upgrading sites, Offshore platforms in the International segment, and the Jackfish and Primrose sites in the North America Exploration and Production segment. The Company continues to mitigate the impact of these costs through its focus on cost control and efficiencies across the asset base.

Canada Emergency Wage Subsidy

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

Liquidity

As at September 30, 2020, the Company had in place revolving bank credit facilities of $4,958 million, of which $3,771 million was available. Including cash and cash equivalents and short-term investments, the Company had approximately $4,218 million in available liquidity.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure.

Capital Spending

Effective and efficient operations will continue to be a focus of the Company. The Company's 2020 capital budget is flexible and disciplined and was originally targeted, when finalized on December 4, 2019, at approximately $4,050 million. In the first quarter of 2020, as a result of the volatility in crude oil pricing, the Company reduced its capital spending budget to approximately $2,960 million. In the second quarter of 2020, the budget was further reduced to approximately $2,680 million, a $1,370 million reduction from the original 2020 budget.

Risks and Uncertainties

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

Benchmark Commodity Prices

(Average for the period)	Three Months Ended Sep 30 2020	Jun 30 2020	Sep 30 2019	Nine Months Ended Sep 30 2020	Sep 30 2019
WTI benchmark price (US$/bbl)	**$ 40.94**	$ 27.85	$ 56.45	**$ 38.30**	$ 57.06
Dated Brent benchmark price (US$/bbl)	**$ 42.74**	$ 31.38	$ 61.85	**$ 41.51**	$ 64.51
WCS Heavy Differential from WTI (US$/bbl)	**$ 9.06**	$ 11.53	$ 12.24	**$ 13.67**	$ 11.76
SCO price (US$/bbl)	**$ 38.61**	$ 23.28	$ 56.87	**$ 35.11**	$ 56.36
Condensate benchmark price (US$/bbl)	**$ 37.55**	$ 22.19	$ 52.00	**$ 35.10**	$ 52.79
Condensate Differential from WTI (US$/bbl)	**$ 3.39**	$ 5.66	$ 4.45	**$ 3.20**	$ 4.27
NYMEX benchmark price (US$/MMBtu)	**$ 1.97**	$ 1.72	$ 2.23	**$ 1.88**	$ 2.67
AECO benchmark price (C$/GJ)	**$ 2.03**	$ 1.81	$ 0.99	**$ 1.96**	$ 1.31
US/Canadian dollar average exchange rate (US$)	**$ 0.7507**	$ 0.7218	$ 0.7573	**$ 0.7384**	$ 0.7523

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.

Effective January 1, 2019, the Government of Alberta implemented a mandatory curtailment program that has been successful in mitigating the discount in crude oil pricing received in Alberta for both light crude oil and heavy crude oil. The Company continues to execute operational flexibility to maximize production volumes through its curtailment optimization strategy, and has significant additional capacity available to further increase production volumes when curtailment restrictions ease. Subsequent to September 30, 2020, the Government of Alberta extended the mandatory curtailment program to December 31, 2021; however, curtailment production limits will be suspended as of December 2020 and curtailment orders will only be issued in 2021 when deemed necessary.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$38.30 per bbl for the nine months ended September 30, 2020, a decrease of 33% from US$57.06 per bbl for the nine months ended September 30, 2019. WTI averaged US$40.94 per bbl for the third quarter of 2020, a decrease of 27% from US$56.45 per bbl for the third quarter of 2019, and an increase of 47% from US$27.85 per bbl for the second 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$41.51 per bbl for the nine months ended September 30, 2020, a decrease of 36% from US$64.51 per bbl for the nine months ended September 30, 2019. Brent averaged US$42.74 per bbl for the third quarter of 2020, a decrease of 31% from US$61.85 per bbl for the third quarter of 2019, and an increase of 36% from US$31.38 per bbl for the second quarter of 2020.

The decrease in WTI and Brent pricing for the three and nine months ended September 30, 2020 from the comparable periods in 2019 primarily reflected significant reductions in refinery utilization due to decreased demand as a result of COVID-19, resulting in an oversupply of crude oil in the market. The increase in WTI and Brent pricing for the third quarter of 2020 from the second quarter of 2020 primarily reflected the impact of OPEC and Russia's agreement in the second quarter of 2020 to reduce supply, together with a partial recovery in global demand in the third quarter of 2020.

The WCS Heavy Differential averaged US$13.67 per bbl for the nine months ended September 30, 2020, an increase of 16% from US$11.76 per bbl for the nine months ended September 30, 2019. The WCS Heavy Differential averaged US$9.06 per bbl for the third quarter of 2020, a decrease of 26% from US$12.24 per bbl for the third quarter of 2019, and a decrease of 21% from US$11.53 per bbl for the second quarter of 2020. The narrowing of the WCS Heavy Differential for the third quarter of 2020 from the comparable periods primarily reflected the impact of a significant reduction in supply from the Basin due to planned and unplanned outages, together with the partial recovery in global demand. The WCS Heavy Differential in the current and the comparable periods also reflected the impact of the mandatory curtailment program.

The SCO price averaged US$35.11 per bbl for the nine months ended September 30, 2020, a decrease of 38% from US$56.36 per bbl for the nine months ended September 30, 2019. The SCO price averaged US$38.61 per bbl for the third quarter of 2020, a decrease of 32% from US$56.87 per bbl for the third quarter of 2019, and an increase of 66% from US$23.28 per bbl for the second quarter of 2020. The decrease in SCO pricing for the three and nine months ended September 30, 2020 from the comparable periods in 2019 primarily reflected movements in WTI benchmark pricing. The increase in SCO pricing for the third quarter of 2020 from the second quarter of 2020 primarily reflected low SCO pricing in the second quarter of 2020 due to a significant widening of the SCO differential from WTI in May 2020 due to decreased demand as a result of COVID-19.

NYMEX natural gas prices averaged US$1.88 per MMBtu for the nine months ended September 30, 2020, a decrease of 30% from US$2.67 per MMBtu for the nine months ended September 30, 2019. NYMEX natural gas prices averaged US$1.97 per MMBtu for the third quarter of 2020, a decrease of 12% from US$2.23 per MMBtu for the third quarter of 2019, and an increase of 15% from US$1.72 per MMBtu for the second quarter of 2020. The decrease in NYMEX natural gas prices for the three and nine months ended September 30, 2020 from the comparable periods in 2019 primarily reflected production levels exceeding North American demand due to the impact of COVID-19, decreasing Liquefied Natural Gas ("LNG") exports, together with lower seasonal demand. The increase in NYMEX natural gas prices for the third quarter of 2020 from the second quarter of 2020 primarily reflected increased domestic demand and LNG exports, together with lower production levels.

AECO natural gas prices averaged $1.96 per GJ for the nine months ended September 30, 2020, an increase of 50% from $1.31 per GJ for the nine months ended September 30, 2019. AECO natural gas prices averaged $2.03 per GJ for the third quarter of 2020, an increase of 105% from $0.99 per GJ for the third quarter of 2019, and an increase of 12% from $1.81 per GJ for the second quarter of 2020. The increase in AECO natural gas prices for the three and nine months ended September 30, 2020 from the comparable periods primarily reflected lower production levels from the Basin.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**494,952**	413,506	450,662	**455,257**	372,068
North America – Oil Sands Mining and Upgrading [1]	**350,633**	464,318	432,203	**417,439**	407,695
North Sea	**21,220**	26,627	27,454	**25,186**	26,927
Offshore Africa	**17,537**	17,444	21,227	**16,977**	22,341
	884,342	921,895	931,546	**914,859**	829,031
Natural gas (MMcf/d)					
North America	**1,340**	1,431	1,425	**1,393**	1,454
North Sea	**5**	15	20	**14**	24
Offshore Africa	**17**	16	24	**14**	26
	1,362	1,462	1,469	**1,421**	1,504
Total barrels of oil equivalent (BOE/d)	**1,111,286**	1,165,487	1,176,361	**1,151,693**	1,079,641
Product mix					
Light and medium crude oil and NGLs	**11%**	11%	12%	**11%**	14%
Pelican Lake heavy crude oil	**5%**	5%	5%	**5%**	5%
Primary heavy crude oil	**6%**	5%	8%	**6%**	7%
Bitumen (thermal oil)	**26%**	18%	18%	**21%**	13%
Synthetic crude oil [1]	**32%**	40%	36%	**36%**	38%
Natural gas	**20%**	21%	21%	**21%**	23%
Percentage of gross revenue [1] [2] (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**93%**	89%	97%	**92%**	94%
Natural gas	**7%**	11%	3%	**8%**	6%

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

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**455,393**	379,554	397,456	**416,611**	329,126
North America – Oil Sands Mining and Upgrading	**347,475**	462,143	407,592	**413,941**	386,771
North Sea	**21,150**	26,567	27,399	**25,122**	26,873
Offshore Africa	**16,767**	16,739	20,095	**16,269**	21,016
	840,785	885,003	852,542	**871,943**	763,786
Natural gas (MMcf/d)					
North America	**1,298**	1,399	1,421	**1,357**	1,416
North Sea	**5**	15	20	**14**	24
Offshore Africa	**16**	15	22	**14**	23
	1,319	1,429	1,463	**1,385**	1,463
Total barrels of oil equivalent (BOE/d)	**1,060,629**	1,123,221	1,096,329	**1,102,742**	1,007,669

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

Crude oil and NGLs production before royalties for the nine months ended September 30, 2020 averaged 914,859 bbl/d, an increase of 10% from 829,031 bbl/d for the nine months ended September 30, 2019. Crude oil and NGLs production for the third quarter of 2020 of 884,342 bbl/d decreased 5% from 931,546 bbl/d for the third quarter of 2019, and decreased 4% from 921,895 bbl/d for the second quarter of 2020. The increase in crude oil and NGLs production for the nine months ended September 30, 2020 from 2019 primarily reflected increased thermal oil production at Kirby North and Jackfish, and the optimization of steam cycles at Primrose. The decrease in crude oil and NGLs production for the third quarter of 2020 from the comparable periods primarily reflected planned maintenance and turnaround activities in the Oil Sands Mining and Upgrading segment, partially offset by record thermal oil production as a result of the Company's curtailment optimization strategy and improved commodity pricing in the third quarter of 2020. Production for all periods reflected the impact of mandatory Government of Alberta curtailment.

Natural gas production before royalties for the nine months ended September 30, 2020 decreased 6% to 1,421 MMcf/d from 1,504 MMcf/d for the nine months ended September 30, 2019. Natural gas production for the third quarter of 2020 of 1,362 MMcf/d decreased 7% from 1,469 MMcf/d for the third quarter of 2019, and decreased 7% from 1,462 MMcf/d for the second quarter of 2020. The decrease in natural gas production for the three and nine months ended September 30, 2020 from the comparable periods primarily reflected natural field declines and planned maintenance and turnaround activities in the third quarter of 2020, partially offset by the added natural gas volumes from opportunities identified by the Company in the first half of 2020. The decrease in natural gas production also reflected the permanent cessation of production at the Banff and Kyle fields in the North Sea and natural field declines in the International segments.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the nine months ended September 30, 2020 averaged 455,257 bbl/d, an increase of 22% from 372,068 bbl/d for the nine months ended September 30, 2019. North America crude oil and NGLs production for the third quarter of 2020 of 494,952 bbl/d increased 10% from 450,662 bbl/d for the third quarter of 2019, and increased 20% from 413,506 bbl/d for the second quarter of 2020. The increase in production for the three and nine months ended September 30, 2020 from the comparable periods in 2019 primarily reflected increased thermal oil production at Kirby North and Jackfish, and the optimization of steam cycles at Primrose. The increase in production for the third quarter of 2020 from the second quarter of 2020 was primarily a result of the Company's curtailment optimization strategy. Production for all periods reflected the impact of mandatory Government of Alberta curtailment.

Thermal oil production before royalties for the third quarter of 2020 averaged 287,978 bbl/d, an increase of 40% from 206,395 bbl/d for the third quarter of 2019, and an increase of 35% from 212,807 bbl/d for the second quarter of 2020. The increase in thermal oil production from the third quarter of 2019 primarily reflected the impact of increased production at Kirby North and Jackfish, and the optimization of steam cycles at Primrose. Thermal oil production increased from the second quarter of 2020 primarily as a result of the Company's curtailment optimization strategy.

Pelican Lake heavy crude oil production before royalties averaged 56,392 bbl/d for the third quarter of 2020, a decrease of 6% from 60,146 bbl/d for the third quarter of 2019, reflecting the field's low natural decline rate, and a slight increase from 55,731 bbl/d for the second quarter of 2020, reflecting reduced well servicing in the second quarter of 2020 due to low commodity prices.

Natural gas production before royalties for the nine months ended September 30, 2020 decreased 4% to 1,393 MMcf/d from 1,454 MMcf/d for the nine months ended September 30, 2019. Natural gas production for the third quarter of 2020 averaged 1,340 MMcf/d, a decrease of 6% from 1,425 MMcf/d for the third quarter of 2019, and a decrease of 6% from 1,431 MMcf/d for the second quarter of 2020. The decrease in natural gas production for the three and nine months ended September 30, 2020 from the comparable periods primarily reflected natural field declines and planned maintenance and turnaround activities in the third quarter of 2020, partially offset by the added natural gas volumes from opportunities identified by the Company in the first half of 2020.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the nine months ended September 30, 2020 of 417,439 bbl/d was comparable with 407,695 bbl/d for the nine months ended September 30, 2019. SCO production for the third quarter of 2020 decreased 19% to average 350,633 bbl/d from 432,203 bbl/d for the third quarter of 2019 and decreased 24% from 464,318 bbl/d for the second quarter of 2020. The decrease in production for the third quarter of 2020 from the comparable periods was due to planned maintenance and turnaround activities at AOSP and Horizon.

North Sea

North Sea crude oil production before royalties for the nine months ended September 30, 2020 of 25,186 bbl/d decreased 6% from 26,927 bbl/d for the nine months ended September 30, 2019. North Sea crude oil production for the third quarter of 2020 decreased 23% to 21,220 bbl/d from 27,454 bbl/d for the third quarter of 2019 and decreased 20% from 26,627 bbl/d for the second quarter of 2020. The decrease in production for the three and nine months ended September 30, 2020 from the comparable periods in 2019 was primarily due to natural field declines and the permanent cessation of production at the Banff and Kyle fields on June 1, 2020. The decrease in production for the third quarter of 2020 from the second quarter of 2020 primarily reflected natural field declines, the permanent cessation of production at the Banff and Kyle fields on June 1, 2020 and planned maintenance and turnaround activities during the third quarter of 2020.

Offshore Africa

Offshore Africa crude oil production before royalties for the nine months ended September 30, 2020 decreased 24% to 16,977 bbl/d from 22,341 bbl/d for the nine months ended September 30, 2019. Offshore Africa crude oil production for the third quarter of 2020 of 17,537 bbl/d decreased 17% from 21,227 bbl/d for the third quarter of 2019 and was comparable with 17,444 bbl/d for the second quarter of 2020. The decrease in production for the three and nine months ended September 30, 2020 from the comparable periods in 2019 primarily reflected natural field declines.

International Crude Oil Inventory Volumes

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

(bbl)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019
North Sea	**730,801**	190,135	871,362
Offshore Africa	**779,347**	1,375,747	309,443
	1,510,148	1,565,882	1,180,805

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 40.14**	$ 18.97	$ 55.19	**$ 28.91**	$ 57.49
Transportation	**3.60**	4.20	3.69	**3.87**	3.47
Realized sales price, net of transportation	**36.54**	14.77	51.50	**25.04**	54.02
Royalties	**3.03**	1.48	6.02	**2.33**	6.11
Production expense	**11.03**	12.53	13.25	**12.41**	14.39
Netback	**$ 22.48**	$ 0.76	$ 32.23	**$ 10.30**	$ 33.52
Natural gas ($/Mcf) (1)					
Sales price	**$ 2.31**	$ 2.03	$ 1.64	**$ 2.19**	$ 2.24
Transportation	**0.42**	0.41	0.40	**0.44**	0.42
Realized sales price, net of transportation	**1.89**	1.62	1.24	**1.75**	1.82
Royalties	**0.07**	0.05	0.01	**0.06**	0.07
Production expense	**1.18**	1.15	1.12	**1.21**	1.23
Netback	**$ 0.64**	$ 0.42	$ 0.11	**$ 0.48**	$ 0.52
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 32.28**	$ 16.57	$ 40.36	**$ 23.82**	$ 41.02
Transportation	**3.28**	3.61	3.27	**3.46**	3.11
Realized sales price, net of transportation	**29.00**	12.96	37.09	**20.36**	37.91
Royalties	**2.25**	1.05	4.07	**1.69**	3.98
Production expense	**9.84**	10.55	11.11	**10.76**	11.76
Netback	**$ 16.91**	$ 1.36	$ 21.91	**$ 7.91**	$ 22.17

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 38.86**	$ 17.22	$ 51.51	**$ 27.11**	$ 53.83
North Sea	**$ 57.84**	$ 45.60	$ 83.64	**$ 48.36**	$ 86.25
Offshore Africa	**$ 55.11**	$ 29.40	$ 82.97	**$ 51.74**	$ 86.79
Average	**$ 40.14**	$ 18.97	$ 55.19	**$ 28.91**	$ 57.49
Natural gas ($/Mcf) (1)					
North America	**$ 2.25**	$ 1.97	$ 1.51	**$ 2.12**	$ 2.07
North Sea	**$ 3.44**	$ 1.42	$ 4.67	**$ 2.87**	$ 7.03
Offshore Africa	**$ 7.32**	$ 8.75	$ 7.08	**$ 8.22**	$ 7.12
Average	**$ 2.31**	$ 2.03	$ 1.64	**$ 2.19**	$ 2.24
Average ($/BOE) (1) (2)	**$ 32.28**	$ 16.57	$ 40.36	**$ 23.82**	$ 41.02

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

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

North America

North America realized crude oil prices decreased 50% to average $27.11 per bbl for the nine months ended September 30, 2020 from $53.83 per bbl for the nine months ended September 30, 2019. North America realized crude oil prices averaged $38.86 per bbl for the third quarter of 2020, a decrease of 25% compared with $51.51 per bbl for the third quarter of 2019, and an increase of 126% compared with $17.22 per bbl for the second quarter of 2020. The decrease in realized crude oil prices for the three and nine months ended September 30, 2020 from the comparable periods in 2019 was primarily due to lower WTI benchmark pricing due to decreased demand as a result of COVID-19, together with fluctuations in the WCS Heavy Differential. The increase in realized crude oil prices for the third quarter of 2020 from the second quarter of 2020 primarily reflected higher WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and in the third quarter of 2020 contributed approximately 169,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices of $2.12 per Mcf for the nine months ended September 30, 2020 was comparable with $2.07 per Mcf for the nine months ended September 30, 2019. North America realized natural gas prices increased 49% to average $2.25 per Mcf for the third quarter of 2020 from $1.51 per Mcf for the third quarter of 2019, and increased 14% from $1.97 per Mcf for the second quarter of 2020. The increase in realized natural gas prices for the third quarter of 2020 from the comparable periods primarily reflected lower production levels from the Basin.

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

	Three Months Ended		
(Quarterly average)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 36.48**	$ 20.36	$ 48.21
Pelican Lake heavy crude oil ($/bbl)	**$ 42.97**	$ 20.98	$ 56.75
Primary heavy crude oil ($/bbl)	**$ 42.63**	$ 17.98	$ 55.47
Bitumen (thermal oil) ($/bbl)	**$ 37.78**	$ 14.79	$ 49.80
Natural gas ($/Mcf)	**$ 2.25**	$ 1.97	$ 1.51

(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 of $48.36 per bbl for the nine months ended September 30, 2020 decreased 44% from $86.25 per bbl for the nine months ended September 30, 2019. North Sea realized crude oil prices decreased 31% to average $57.84 per bbl for the third quarter of 2020 from $83.64 per bbl for the third quarter of 2019 and increased 27% from $45.60 per bbl for the second 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 fluctuations in realized crude oil prices for the three and nine months ended September 30, 2020 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 40% to average $51.74 per bbl for the nine months ended September 30, 2020 from $86.79 per bbl for the nine months ended September 30, 2019. Offshore Africa realized crude oil prices decreased 34% to average $55.11 per bbl for the third quarter of 2020 from $82.97 per bbl for the third quarter of 2019 and increased 87% from $29.40 per bbl for the second 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 fluctuations in realized crude oil prices for the three and nine months ended September 30, 2020 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 3.15**	$ 1.56	$ 6.50	**$ 2.45**	$ 6.57
North Sea	**$ 0.19**	$ 0.10	$ 0.17	**$ 0.12**	$ 0.18
Offshore Africa	**$ 2.42**	$ 1.19	$ 4.43	**$ 2.19**	$ 4.77
Average	**$ 3.03**	$ 1.48	$ 6.02	**$ 2.33**	$ 6.11
Natural gas ($/Mcf) (1)					
North America	**$ 0.07**	$ 0.04	$ 0.01	**$ 0.05**	$ 0.06
Offshore Africa	**$ 0.34**	$ 0.40	$ 0.63	**$ 0.40**	$ 0.69
Average	**$ 0.07**	$ 0.05	$ 0.01	**$ 0.06**	$ 0.07
Average ($/BOE) (1)	**$ 2.25**	$ 1.05	$ 4.07	**$ 1.69**	$ 3.98

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

North America

North America crude oil and natural gas royalties for the three and nine months ended September 30, 2020 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates averaged approximately 9% of product sales for the nine months ended September 30, 2020 compared with 12% of product sales for the nine months ended September 30, 2019. Crude oil and NGLs royalty rates averaged approximately 8% of product sales for the third quarter of 2020 compared with 13% for the third quarter of 2019 and 9% for the second quarter of 2020. The decrease in royalty rates for the three and nine months ended September 30, 2020 from the comparable periods in 2019 primarily reflected lower benchmark prices together with fluctuations in the WCS Heavy Differential. The decrease in the royalty rate for the third quarter of 2020 from the second quarter of 2020 was primarily due to royalty adjustments in the third quarter to reflect expected annualized thermal oil pricing.

Natural gas royalty rates averaged approximately 3% of product sales for the nine months ended September 30, 2020 compared with 3% of product sales for the nine months ended September 30, 2019. Natural gas royalty rates averaged approximately 3% of product sales for the third quarter of 2020 compared with 1% for the third quarter of 2019 and 2% for the second quarter of 2020. The increase in royalty rates for the third quarter of 2020 from the comparable periods primarily reflected higher realized natural gas prices.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 4% for the nine months ended September 30, 2020, compared with 6% of product sales for the nine months ended September 30, 2019. Royalty rates as a percentage of product sales averaged approximately 4% for the third quarter of 2020, compared with 6% of product sales for the third quarter of 2019 and 4% for the second 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			Nine Months Ended	
	Sep 30 2020	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 9.80**	$ 11.65	$ 11.86	**$ 11.34**	$ 13.16
North Sea	**$ 42.10**	$ 28.47	$ 37.11	**$ 31.99**	$ 37.78
Offshore Africa	**$ 16.41**	$ 10.62	$ 11.06	**$ 13.94**	$ 9.87
Average	**$ 11.03**	$ 12.53	$ 13.25	**$ 12.41**	$ 14.39
Natural gas ($/Mcf) [(1)]					
North America	**$ 1.14**	$ 1.11	$ 1.07	**$ 1.16**	$ 1.17
North Sea	**$ 5.38**	$ 3.18	$ 3.08	**$ 3.56**	$ 3.45
Offshore Africa	**$ 3.03**	$ 3.46	$ 2.78	**$ 3.79**	$ 2.45
Average	**$ 1.18**	$ 1.15	$ 1.12	**$ 1.21**	$ 1.23
Average ($/BOE) [(1)]	**$ 9.84**	$ 10.55	$ 11.11	**$ 10.76**	$ 11.76

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

North America

North America crude oil and NGLs production expense for the nine months ended September 30, 2020 averaged $11.34 per bbl, a decrease of 14% from $13.16 per bbl for the nine months ended September 30, 2019. North America crude oil and NGLs production expense for the third quarter of 2020 of $9.80 per bbl decreased 17% from $11.86 per bbl for the third quarter of 2019 and decreased 16% from $11.65 per bbl for the second quarter of 2020. The decrease in crude oil and NGLs production expense per bbl for the three and nine months ended September 30, 2020 from the comparable periods primarily reflected the impact of increased thermal oil production together with operating cost synergies at Jackfish. The Company continues to focus on cost control and achieving efficiencies across the entire asset base.

North America natural gas production expense for the nine months ended September 30, 2020 averaged $1.16 per Mcf, comparable with $1.17 per Mcf for the nine months ended September 30, 2019, reflecting the Company's strategy to own and control its infrastructure and its continued focus on cost control. North America natural gas production expense for the third quarter of 2020 of $1.14 per Mcf increased 7% from $1.07 per Mcf for the third quarter of 2019 and increased 3% from $1.11 per Mcf for the second quarter of 2020. The increase in natural gas production expense per Mcf for the third quarter of 2020 from the comparable periods primarily reflected the impact of lower volumes on a relatively fixed cost base.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2020 decreased 15% to $31.99 per bbl from $37.78 per bbl for the nine months ended September 30, 2019. North Sea crude oil production expense for the third quarter of 2020 of $42.10 per bbl increased 13% from $37.11 per bbl for the third quarter of 2019 and increased 48% from $28.47 per bbl for the second quarter of 2020. The decrease in crude oil production expense per bbl for the nine months ended September 30, 2020 from the comparable period in 2019 primarily reflected the Company's continuous focus on cost control. The increase in crude oil production expense per bbl for the third quarter of 2020 from the third quarter of 2019 was primarily due to fluctuations in the Canadian dollar. The increase for the third quarter of 2020 from the second quarter of 2020 primarily reflected lower production on a relatively fixed cost base, together with the timing of liftings from various fields that have different cost structures.

Offshore Africa

Offshore Africa crude oil production expense for the nine months ended September 30, 2020 increased 41% to $13.94 per bbl from $9.87 per bbl for the nine months ended September 30, 2019. Offshore Africa crude oil production expense for the third quarter of 2020 of $16.41 per bbl increased 48% from $11.06 per bbl for the third quarter of 2019 and increased 55% from $10.62 per bbl for the second quarter of 2020. The increase in crude oil production expense per bbl for the three and nine months ended September 30, 2020 from the comparable periods primarily reflected the timing of liftings from various fields that have different cost structures. Offshore Africa production expense also reflected fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Expense	**$ 1,046**	$ 974	$ 1,021	**$ 3,115**	$ 2,793
$/BOE (1)	**$ 15.01**	$ 15.47	$ 14.89	**$ 15.41**	$ 15.32

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

Depletion, depreciation and amortization expense for the nine months ended September 30, 2020 of $15.41 per BOE was comparable with $15.32 per BOE for the nine months ended September 30, 2019. Depletion, depreciation and amortization expense for the third quarter of 2020 of $15.01 per BOE was comparable with $14.89 per BOE for the third quarter of 2019 and decreased 3% from $15.47 per BOE for the second quarter of 2020.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Expense	**$ 32**	$ 33	$ 34	**$ 100**	$ 93
$/BOE (1)	**$ 0.47**	$ 0.53	$ 0.51	**$ 0.50**	$ 0.51

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

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

Asset retirement obligation accretion expense for the nine months ended September 30, 2020 of $0.50 per BOE was comparable with $0.51 per BOE for the nine months ended September 30, 2019. Asset retirement obligation accretion expense for the third quarter of 2020 of $0.47 per BOE decreased 8% from $0.51 per BOE for the third quarter of 2019 and decreased 11% from $0.53 per BOE for the second quarter of 2020. Fluctuations in asset retirement obligation accretion expense on a per BOE basis primarily reflect fluctuating sales volumes.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. Production in the third quarter of 2020 averaged 350,633 bbl/d, reflecting planned maintenance and turnaround activities at AOSP and Horizon.

The Company incurred production costs of $2,327 million for the nine months ended September 30, 2020, a $93 million decrease, or 4% decrease from the nine months ended September 30, 2019.

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

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
SCO realized sales price (2)	**$ 48.92**	$ 29.11	$ 71.60	**$ 42.40**	$ 70.64
Bitumen value for royalty purposes (3)	**$ 36.26**	$ 18.35	$ 51.70	**$ 22.77**	$ 52.64
Bitumen royalties (4)	**$ 0.46**	$ 0.15	$ 3.76	**$ 0.49**	$ 3.27
Transportation	**$ 1.30**	$ 0.97	$ 1.16	**$ 1.17**	$ 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 $42.40 per bbl for the nine months ended September 30, 2020, a decrease of 40% from $70.64 per bbl for the nine months ended September 30, 2019. For the third quarter of 2020, the realized sales price decreased 32% to $48.92 per bbl from $71.60 per bbl for the third quarter of 2019 and increased 68% from $29.11 per bbl for the second quarter of 2020. The decrease in the realized SCO sales price for the three and nine months ended September 30, 2020 from the comparable periods in 2019 primarily reflected movements in WTI benchmark pricing. The increase in SCO sales price for the third quarter of 2020 from the second quarter of 2020 primarily reflected low SCO pricing in the second quarter of 2020 due to a significant widening of the SCO differential from WTI in May 2020 due to decreased demand as a result of COVID-19.

Transportation expense averaged $1.17 per bbl for the nine months ended September 30, 2020, a decrease of 9% from $1.28 per bbl for the nine months ended September 30, 2019. For the third quarter of 2020, transportation expense increased 12% to $1.30 per bbl from $1.16 per bbl for the third quarter of 2019 and increased 34% from $0.97 per bbl for the second quarter of 2020. The decrease in transportation expense for the nine months ended September 30, 2020 from the nine months ended September 30, 2019 primarily reflected a slight increase in production volumes, together with lower pipeline charges in 2020. The increase in transportation expense for the third quarter of 2020 from the comparable periods primarily reflected decreased production volumes.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Production costs, excluding natural gas costs	**$ 760**	$ 699	$ 769	**$ 2,232**	$ 2,337
Natural gas costs	**28**	31	15	**95**	83
Production costs	**$ 788**	$ 730	$ 784	**$ 2,327**	$ 2,420

($/bbl) (1)	Three Months Ended Sep 30 2020	Jun 30 2020	Sep 30 2019	Nine Months Ended Sep 30 2020	Sep 30 2019
Production costs, excluding natural gas costs	**$ 22.96**	$ 16.98	$ 19.66	**$ 19.71**	$ 21.04
Natural gas costs	**0.85**	0.76	0.39	**0.84**	0.75
Production costs	**$ 23.81**	$ 17.74	$ 20.05	**$ 20.55**	$ 21.79
Sales (bbl/d)	**359,479**	452,066	425,140	**413,157**	406,923

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

Production costs for the nine months ended September 30, 2020 decreased 6% to $20.55 per bbl from $21.79 per bbl for the nine months ended September 30, 2019. Production costs for the third quarter of 2020 averaged $23.81 per bbl, an increase of 19% from $20.05 per bbl for the third quarter of 2019 and an increase of 34% from $17.74 per bbl for the second quarter of 2020.

The decrease in production costs per bbl for the nine months ended September 30, 2020 from the nine months ended September 30, 2019 primarily reflected high reliability and operational enhancements at both Horizon and AOSP. The increase in production costs per bbl for the third quarter of 2020 from the comparable periods primarily reflected lower production volumes due to the planned maintenance and turnaround activities at AOSP and Horizon. The Company continued to focus on cost control and efficiencies across the entire asset base.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended Sep 30 2020	Jun 30 2020	Sep 30 2019	Nine Months Ended Sep 30 2020	Sep 30 2019
Expense	**$ 414**	$ 451	$ 401	**$ 1,305**	$ 1,192
$/bbl (1)	**$ 12.51**	$ 10.97	$ 10.26	**$ 11.53**	$ 10.73

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

Depletion, depreciation and amortization expense for the nine months ended September 30, 2020 of $11.53 per bbl increased 7% from $10.73 per bbl for the nine months ended September 30, 2019. Depletion, depreciation and amortization expense for the third quarter of 2020 of $12.51 per bbl increased 22% from $10.26 per bbl for the third quarter of 2019, and increased 14% from $10.97 per bbl for the second quarter of 2020. Fluctuations in depletion, depreciation and amortization on a per barrel basis primarily reflect fluctuations in sales volumes from underlying operations.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended Sep 30 2020	Jun 30 2020	Sep 30 2019	Nine Months Ended Sep 30 2020	Sep 30 2019
Expense	**$ 19**	$ 18	$ 16	**$ 54**	$ 47
$/bbl (1)	**$ 0.55**	$ 0.44	$ 0.38	**$ 0.47**	$ 0.41

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

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

Asset retirement obligation accretion expense for the nine months ended September 30, 2020 of $0.47 per bbl increased 15% from $0.41 per bbl for the nine months ended September 30, 2019. Asset retirement obligation accretion expense of $0.55 per bbl for the third quarter of 2020 increased 45% from $0.38 per bbl for the third quarter of 2019 and increased 25% from $0.44 per bbl for the second quarter of 2020. Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended **Sep 30 2020**	Jun 30 2020	Sep 30 2019	Nine Months Ended **Sep 30 2020**	Sep 30 2019
Product sales					
Crude oil and NGLs, midstream activities	**$ 21**	$ 20	$ 21	**$ 62**	$ 62
NWRP, refined product sales	**78**	25	—	**103**	—
Segmented revenue	**99**	45	21	**165**	62
Less:					
Production expenses					
NWRP, refining toll	**70**	24	—	**94**	—
Midstream	**4**	5	4	**15**	15
NWRP, transportation and feedstock costs	**76**	22	—	**98**	—
Depreciation	**4**	3	4	**11**	11
Equity loss from investment in NWRP	**—**	—	88	**—**	214
Segmented loss before taxes	**$ (55)**	$ (9)	$ (75)	**$ (53)**	$ (178)

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 the 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 ("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. For the three months ended September 30, 2020, production of ultra-low sulphur diesel and other refined products averaged 52,678 BOE/d (13,169 BOE/d to the Company).

The Company's unrecognized share of the equity (income) loss from NWRP for the three months ended September 30, 2020 was a recovery of unrecognized losses of $16 million (nine months ended September 30, 2020 – unrecognized equity loss of $100 million). As at September 30, 2020, the cumulative unrecognized share of losses from NWRP was $159 million (December 31, 2019 – $59 million).

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended **Sep 30 2020**	Jun 30 2020	Sep 30 2019	Nine Months Ended **Sep 30 2020**	Sep 30 2019
Expense	**$ 88**	$ 88	$ 95	**$ 284**	$ 249
$/BOE (1)	**$ 0.85**	$ 0.84	$ 0.88	**$ 0.90**	$ 0.85

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

Administration expense for the nine months ended September 30, 2020 of $0.90 per BOE increased 6% from $0.85 per BOE for the nine months ended September 30, 2019. Administration expense for the third quarter of 2020 of $0.85 per BOE decreased 3% from $0.88 per BOE for the third quarter of 2019 and was comparable with $0.84 per BOE for the second quarter of 2020. Administration expense per BOE increased for the nine months ended September 30, 2020 from the nine months ended September 30, 2019 primarily due to the impact of higher personnel and corporate costs, including those associated with the acquisition of assets from Devon, and lower overhead recoveries. Administration expense per BOE decreased for the third quarter of 2020 from the third quarter of 2019 primarily due to lower personnel costs.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Sep 30 2020	Jun 30 2020	Sep 30 2019	Nine Months Ended Sep 30 2020	Sep 30 2019
(Recovery) expense	**$ (5)**	$ 23	$ 7	**$ (205)**	$ 62

The Company's Stock Option Plan provides current 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 $205 million share-based compensation recovery for the nine months ended September 30, 2020, primarily as a result of the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period, and changes in the Company's share price. Included within the share-based compensation recovery for the nine months ended September 30, 2020 was a recovery of $4 million related to PSUs granted to certain executive employees (September 30, 2019 – $16 million expense). For the nine months ended September 30, 2020, the Company charged $4 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (September 30, 2019 – $4 million charged).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Sep 30 2020	Jun 30 2020	Sep 30 2019	Nine Months Ended Sep 30 2020	Sep 30 2019
Expense, gross	**$ 180**	$ 206	$ 239	**$ 600**	$ 664
Less: capitalized interest	**6**	7	8	**21**	45
Expense, net	**$ 174**	$ 199	$ 231	**$ 579**	$ 619
$/BOE (1)	**$ 1.69**	$ 1.91	$ 2.14	**$ 1.84**	$ 2.11
Average effective interest rate	**3.4%**	3.5%	3.9%	**3.6%**	4.0%

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

Gross interest and other financing expense for the three and nine months ended September 30, 2020 decreased from the comparable periods primarily due to lower interest rates. Capitalized interest of $21 million for the nine months ended September 30, 2020 was related to residual project activities at Horizon.

Net interest and other financing expense per BOE for the nine months ended September 30, 2020 decreased 13% to $1.84 per BOE from $2.11 per BOE for the nine months ended September 30, 2019. Net interest and other financing expense per BOE for the third quarter of 2020 decreased 21% to $1.69 per BOE from $2.14 per BOE for the third quarter of 2019 and decreased 12% from $1.91 per BOE for the second quarter of 2020. The decrease in net interest and other financing expense per BOE for the three and nine months ended September 30, 2020 from the comparable periods was primarily due to lower average interest rates.

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

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Foreign currency contracts	**$ 20**	$ 28	$ (8)	**$ (9)**	$ 8
Natural gas financial instruments	**5**	3	(4)	**18**	(7)
Crude oil and NGLs financial instruments	**—**	—	11	**—**	52
Net realized loss (gain)	**25**	31	(1)	**9**	53
Foreign currency contracts	**—**	—	(2)	**(9)**	5
Natural gas financial instruments	**(2)**	1	7	**(9)**	8
Crude oil and NGLs financial instruments	**—**	—	(7)	**—**	(17)
Net unrealized (gain) loss	**(2)**	1	(2)	**(18)**	(4)
Net loss (gain)	**$ 23**	$ 32	$ (3)	**$ (9)**	$ 49

During the nine months ended September 30, 2020, net realized risk management losses were related to the settlement of foreign currency contracts and natural gas financial instruments. The Company recorded a net unrealized gain of $18 million ($15 million after-tax) on its risk management activities for the nine months ended September 30, 2020, including an unrealized gain of $2 million ($1 million after-tax) for the third quarter of 2020 (June 30, 2020 – unrealized loss of $1 million, $1 million after-tax; September 30, 2019 – unrealized gain of $2 million, $2 million after-tax).

Further details related to outstanding derivative financial instruments at September 30, 2020 are disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Net realized loss (gain)	**$ 16**	$ 3	$ (14)	**$ (180)**	$ (18)
Net unrealized (gain) loss	**(270)**	(433)	129	**418**	(323)
Net (gain) loss [(1)]	**$ (254)**	$ (430)	$ 115	**$ 238**	$ (341)

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

The net realized foreign exchange gain for the nine months ended September 30, 2020 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the settlement of the US$500 million cross currency swaps during the first quarter of 2020. The net unrealized foreign exchange loss for the nine months ended September 30, 2020 was primarily related to the impact of a weaker 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 in the first quarter of 2020 (three months ended September 30, 2020 – unrealized loss of $16 million, June 30, 2020 – unrealized loss of $28 million, September 30, 2019 – unrealized gain of $16 million; nine months ended September 30, 2020 – unrealized loss of $118 million, September 30, 2019 – unrealized loss of $42 million). The US/Canadian dollar exchange rate at September 30, 2020 was US$0.7505 (June 30, 2020 – US$0.7345, September 30, 2019 – US$0.7551).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Sep 30 2020	Three Months Ended Jun 30 2020	Three Months Ended Sep 30 2019	Nine Months Ended Sep 30 2020	Nine Months Ended Sep 30 2019
North America [1]	**$ (59)**	$ (34)	$ 133	**$ (287)**	$ 374
North Sea	**(14)**	1	15	**(4)**	72
Offshore Africa	**6**	2	14	**12**	37
PRT [2] – North Sea	**(17)**	—	(4)	**(17)**	(89)
Other taxes	**2**	—	3	**4**	9
Current income tax (recovery) expense	**(82)**	(31)	161	**(292)**	403
Deferred corporate income tax expense (recovery)	**91**	(267)	176	**(156)**	(1,089)
Deferred PRT [2] – North Sea	**—**	—	—	**—**	1
Deferred income tax expense (recovery)	**91**	(267)	176	**(156)**	(1,088)
Income tax expense (recovery)	**9**	(298)	337	**(448)**	(685)
Income tax rate and other legislative changes	**—**	—	—	**—**	1,618
	$ 9	$ (298)	$ 337	**$ (448)**	$ 933
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**15%**	28%	22%	**32%**	25%

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

(2) Petroleum Revenue Tax

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

The effective income tax rate for the three and nine months ended September 30, 2020 and the comparable periods included the impact of non-taxable items in North America and North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings (loss).

The current corporate income tax and PRT in the North Sea for the nine months ended September 30, 2020 and the prior periods included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. Subsequent to September 30, 2020, the Government of Alberta substantively enacted legislation to accelerate this reduction, lowering the corporate tax rate from 10% to 8%, effective July 1, 2020.

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

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Sep 30 2020	Three Months Ended Jun 30 2020	Three Months Ended Sep 30 2019	Nine Months Ended Sep 30 2020	Nine Months Ended Sep 30 2019
Exploration and Evaluation					
Net property (dispositions) acquisitions [2]	**$ (12)**	$ —	$ (2)	**$ (30)**	$ 90
Net expenditures	**1**	1	5	**27**	74
Total Exploration and Evaluation	**(11)**	1	3	**(3)**	164
Property, Plant and Equipment					
Net property (dispositions) acquisitions [2]	**(1)**	2	30	**14**	3,188
Well drilling, completion and equipping	**80**	32	181	**314**	606
Production and related facilities	**157**	78	232	**449**	790
Capitalized interest and other	**14**	14	14	**40**	66
Total Property, Plant and Equipment	**250**	126	457	**817**	4,650
Total Exploration and Production	**239**	127	460	**814**	4,814
Oil Sands Mining and Upgrading					
Project costs	**67**	49	133	**172**	315
Sustaining capital	**254**	172	249	**627**	599
Turnaround costs	**131**	20	36	**174**	61
Capitalized interest and other	**8**	9	10	**26**	29
Total Oil Sands Mining and Upgrading	**460**	250	428	**999**	1,004
Midstream and Refining	**1**	2	4	**4**	9
Abandonments [3]	**68**	40	63	**197**	212
Head office	**3**	2	8	**16**	26
Total net capital expenditures	**$ 771**	$ 421	$ 963	**$ 2,030**	$ 6,065
By segment					
North America [2]	**$ 170**	$ 95	$ 365	**$ 660**	$ 4,501
North Sea	**45**	17	55	**88**	133
Offshore Africa	**24**	15	40	**66**	180
Oil Sands Mining and Upgrading	**460**	250	428	**999**	1,004
Midstream and Refining	**1**	2	4	**4**	9
Abandonments [3]	**68**	40	63	**197**	212
Head office	**3**	2	8	**16**	26
Total	**$ 771**	$ 421	$ 963	**$ 2,030**	$ 6,065

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

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

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

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

($ millions)	Three Months Ended Sep 30 2020	Jun 30 2020	Sep 30 2019	Nine Months Ended Sep 30 2020	Sep 30 2019
Cash flows used in investing activities	***$ 643***	*$ 693*	*$ 908*	***$ 2,195***	*$ 6,401*
Net change in non-cash working capital [(1)]	***60***	*(312)*	*(8)*	***(362)***	*(548)*
Abandonment expenditures [(2)]	***68***	*40*	*63*	***197***	*212*
Net capital expenditures	***$ 771***	*$ 421*	*$ 963*	***$ 2,030***	*$ 6,065*

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

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

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.

2020 Capital Budget

The Company's 2020 capital budget is flexible and disciplined and was originally targeted, when finalized on December 4, 2019, at approximately $4,050 million. In the first quarter of 2020, as a result of the volatility in crude oil pricing, the Company reduced its capital spending budget to approximately $2,960 million. In the second quarter of 2020, the budget was further reduced to approximately $2,680 million, a $1,370 million reduction from the original 2020 budget.

Subsequent to September 30, 2020, the Company completed the acquisition of all of the issued and outstanding common shares of Painted Pony Energy Ltd. ("Painted Pony") for net cash consideration of approximately $111 million. At closing, the acquisition also included the assumption of long-term debt of approximately $397 million and certain other obligations, which will be included in the initial purchase accounting for the acquisition. Painted Pony is involved in the exploration for and development of natural gas and natural gas liquids in Northeast British Columbia.

Drilling Activity [(1)]

(number of net wells)	Three Months Ended Sep 30 2020	Jun 30 2020	Sep 30 2019	Nine Months Ended Sep 30 2020	Sep 30 2019
Net successful natural gas wells	**9**	1	5	**21**	15
Net successful crude oil wells [(2)]	**—**	2	36	**37**	74
Dry wells	**—**	—	—	**—**	3
Stratigraphic test / service wells	**1**	4	23	**372**	358
Total	**10**	7	64	**430**	450
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	100%	**100%**	97%

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

(2) Includes bitumen wells.

North America

During the third quarter of 2020, the Company targeted 9 net natural gas wells.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2020**	Jun 30 2020	Dec 31 2019	Sep 30 2019
Working capital (1)	**$ 707**	$ 993	$ 241	$ 859
Long-term debt (2) (3)	**$ 21,876**	$ 23,020	$ 20,982	$ 22,489
Less: cash and cash equivalents	**175**	233	139	176
Long-term debt, net	**$ 21,701**	$ 22,787	$ 20,843	$ 22,313
Share capital	**$ 9,522**	$ 9,521	$ 9,533	$ 9,314
Retained earnings	**22,520**	22,614	25,424	25,382
Accumulated other comprehensive income	**124**	198	34	98
Shareholders' equity	**$ 32,166**	$ 32,333	$ 34,991	$ 34,794
Debt to book capitalization (3) (4)	**40.3%**	41.3%	37.3%	39.1%
Debt to market capitalization (3) (5)	**46.3%**	45.0%	29.5%	34.8%
After-tax return on average common shareholders' equity (6)	**(1.8)%**	0.1%	16.1%	12.1%
After-tax return on average capital employed (3) (7)	**0.0 %**	1.2%	10.9%	8.4%

(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 for the twelve month trailing period.

As at September 30, 2020, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Business Environment" section of this MD&A and in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2019. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and market conditions. The Company continues to believe that its internally generated cash flows from operating activities supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy.

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

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

- Reviewing the Company's borrowing capacity:
  - During the second quarter of 2020, the $750 million non-revolving term credit facility, originally due February 2021, was extended to February 2022 and increased to $1,000 million.
  - During the second quarter of 2020, the Company issued US$600 million of 2.05% notes due July 2025 and US$500 million of 2.95% notes due July 2030.
  - After issuing these securities, the Company had US$1,900 million remaining on its base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2021. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
  - During the third quarter of 2020, the Company repaid $1,000 million of 2.89% medium-term notes.
  - During the second quarter of 2020, the Company repaid $900 million of 2.05% medium-term notes.
  - In July 2019, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 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.
  - 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.
  - Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, US base rate or Canadian prime rate. As at September 30, 2020, the non-revolving term credit facilities were fully drawn.
  - During 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.
  - The Company’s borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

As at September 30, 2020, the Company had in place revolving bank credit facilities of $4,958 million, of which $3,771 million was available. Additionally, the Company had in place fully drawn term credit facilities of $6,738 million. Including cash and cash equivalents and short-term investments, the Company had approximately $4,218 million in available liquidity. This excludes certain other dedicated credit facilities supporting letters of credit.

As at September 30, 2020, the Company had total US dollar denominated debt with a carrying amount of $17,575 million (US$13,191 million), before transaction costs and original issue discounts. This included $6,649 million (US$4,991 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$4,441 million). The fixed repayment amount of these hedging instruments is $6,498 million, resulting in a notional reduction of the carrying amount of the Company’s US dollar denominated debt by approximately $151 million to $17,424 million as at September 30, 2020.

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

Net long-term debt was $21,701 million at September 30, 2020, resulting in a debt to book capitalization ratio of 40.3% (December 31, 2019 – 37.3%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company’s long-term debt at September 30, 2020 are discussed in note 9 of the Company’s unaudited interim consolidated financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at September 30, 2020, the Company was in compliance with this covenant.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company’s cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at September 30, 2020, 102,500 GJ/d of currently forecasted natural gas volumes were hedged using AECO fixed price swaps for October 2020. Further details related to the Company's commodity derivative financial instruments outstanding at September 30, 2020 are discussed in note 16 of the Company's unaudited interim consolidated financial statements.

The maturity dates of long-term debt and other long-term liabilities and related interest payments were as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Long-term debt [(1)]	$	828	$	5,637	$	7,224	$	8,295
Other long-term liabilities [(2)]	$	217	$	186	$	405	$	901
Interest and other financing expense [(3)]	$	780	$	703	$	1,731	$	4,693

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

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows: less than one year, $189 million; one to less than two years, $161 million; two to less than five years, $383 million; and thereafter, $901 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at September 30, 2020.

Share Capital

As at September 30, 2020, there were 1,181,056,000 common shares outstanding (December 31, 2019 – 1,186,857,000 common shares) and 52,313,000 stock options outstanding. As at November 3, 2020, the Company had 1,181,058,000 common shares outstanding and 52,134,000 stock options outstanding.

On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to $0.425 per common share, beginning with the dividend payable on April 1, 2020 (previous quarterly dividend rate of $0.375 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

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

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

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at September 30, 2020:

($ millions)		Remaining 2020		2021		2022		2023		2024		Thereafter
Product transportation [(1)]	$	189	$	749	$	664	$	740	$	715	$	8,015
North West Redwater Partnership service toll [(2)]	$	41	$	164	$	152	$	161	$	160	$	2,825
Offshore vessels and equipment	$	16	$	66	$	9	$	—	$	—	$	—
Field equipment and power	$	12	$	21	$	21	$	21	$	21	$	267
Other	$	6	$	20	$	20	$	20	$	20	$	36

(1) Includes commitments pertaining to a 20-year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals. The Company may be required to reimburse certain construction costs to the service provider under certain conditions.

(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 $1,168 million of interest payable over the 30-year tolling period.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

ACCOUNTING POLICIES

Government Grants

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

Changes in Accounting Policies

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

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. For the three and nine months ended September 30, 2020, COVID-19 had an impact on the global economy, including the oil and gas industry. Business conditions in the third quarter of 2020 continued to reflect the market uncertainty associated with COVID-19, with some modest improvements to global crude oil demand and supply conditions. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions, and judgements in the preparation of the unaudited interim consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the Company's annual MD&A and audited consolidated financial statements for the year ended December 31, 2019.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the nine months ended September 30, 2020 that have materially affected, or are reasonably likely to materially affect the Company’s ICFR. Based on inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Sep 30 2020**	Dec 31 2019
ASSETS			
Current assets			
Cash and cash equivalents		**$ 175**	$ 139
Accounts receivable		**1,606**	2,465
Current income taxes receivable		**321**	13
Inventory		**1,083**	1,152
Prepaids and other		**315**	174
Investments	7	**272**	490
Current portion of other long-term assets	8	**263**	54
		4,035	4,487
Exploration and evaluation assets	4	**2,483**	2,579
Property, plant and equipment	5	**64,578**	68,043
Lease assets	6	**1,594**	1,789
Other long-term assets	8	**1,040**	1,223
		$ 73,730	$ 78,121
LIABILITIES			
Current liabilities			
Accounts payable		**$ 825**	$ 816
Accrued liabilities		**2,112**	2,611
Current portion of long-term debt	9	**828**	2,391
Current portion of other long-term liabilities	6,10	**391**	819
		4,156	6,637
Long-term debt	9	**21,048**	18,591
Other long-term liabilities	6,10	**5,962**	7,363
Deferred income taxes		**10,398**	10,539
		41,564	43,130
SHAREHOLDERS' EQUITY			
Share capital	12	**9,522**	9,533
Retained earnings		**22,520**	25,424
Accumulated other comprehensive income	13	**124**	34
		32,166	34,991
		$ 73,730	$ 78,121

Commitments and contingencies (note 17).

Approved by the Board of Directors on November 4, 2020.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Sep 30 2020**	Three Months Ended Sep 30 2019	Nine Months Ended **Sep 30 2020**	Nine Months Ended Sep 30 2019
Product sales	18	**$ 4,676**	$ 6,587	**$ 12,272**	$ 18,059
Less: royalties		**(172)**	(427)	**(397)**	(1,089)
Revenue		**4,504**	6,160	**11,875**	16,970
Expenses					
Production		**1,556**	1,566	**4,649**	4,629
Transportation, blending and feedstock		**989**	1,248	**3,180**	3,283
Depletion, depreciation and amortization	5,6	**1,464**	1,426	**4,431**	3,996
Administration		**88**	95	**284**	249
Share-based compensation	10	**(5)**	7	**(205)**	62
Asset retirement obligation accretion	10	**51**	50	**154**	140
Interest and other financing expense		**174**	231	**579**	619
Risk management activities	16	**23**	(3)	**(9)**	49
Foreign exchange (gain) loss		**(254)**	115	**238**	(341)
Loss from investments	7,8	**1**	61	**206**	150
		4,087	4,796	**13,507**	12,836
Earnings (loss) before taxes		**417**	1,364	**(1,632)**	4,134
Current income tax (recovery) expense	11	**(82)**	161	**(292)**	403
Deferred income tax expense (recovery)	11	**91**	176	**(156)**	(1,088)
Net earnings (loss)		**$ 408**	$ 1,027	**$ (1,184)**	$ 4,819
Net earnings (loss) per common share					
Basic	15	**$ 0.35**	$ 0.87	**$ (1.00)**	$ 4.04
Diluted	15	**$ 0.35**	$ 0.87	**$ (1.00)**	$ 4.03

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended **Sep 30 2020**	Three Months Ended Sep 30 2019	Nine Months Ended **Sep 30 2020**	Nine Months Ended Sep 30 2019
Net earnings (loss)	**$ 408**	$ 1,027	**$ (1,184)**	$ 4,819
Items that may be reclassified subsequently to net earnings (loss)				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $1 million (2019 – $6 million) – three months ended; $2 million (2019 – $12 million) – nine months ended	**(9)**	48	**17**	97
Reclassification to net earnings (loss), net of taxes of $1 million (2019 – $2 million) – three months ended; $2 million (2019 – $5 million) – nine months ended	**(4)**	(13)	**(13)**	(36)
	(13)	35	**4**	61
Foreign currency translation adjustment				
Translation of net investment	**(61)**	36	**86**	(85)
Other comprehensive income (loss), net of taxes	**(74)**	71	**90**	(24)
Comprehensive income (loss)	**$ 334**	$ 1,098	**$ (1,094)**	$ 4,795

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended **Sep 30 2020**	Sep 30 2019
Share capital	12		
Balance – beginning of period		**$ 9,533**	$ 9,323
Issued upon exercise of stock options		**36**	148
Previously recognized liability on stock options exercised for common shares		**9**	17
Purchase of common shares under Normal Course Issuer Bid		**(56)**	(174)
Balance – end of period		**9,522**	9,314
Retained earnings			
Balance – beginning of period		**25,424**	22,529
Net earnings (loss)		**(1,184)**	4,819
Dividends on common shares	12	**(1,505)**	(1,339)
Purchase of common shares under Normal Course Issuer Bid	12	**(215)**	(627)
Balance – end of period		**22,520**	25,382
Accumulated other comprehensive income	13		
Balance – beginning of period		**34**	122
Other comprehensive income (loss), net of taxes		**90**	(24)
Balance – end of period		**124**	98
Shareholders' equity		**$ 32,166**	$ 34,794

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Sep 30 2020**	Three Months Ended Sep 30 2019	Nine Months Ended **Sep 30 2020**	Nine Months Ended Sep 30 2019
Operating activities					
Net earnings (loss)		**$ 408**	$ 1,027	**$ (1,184)**	$ 4,819
Non-cash items					
Depletion, depreciation and amortization		**1,464**	1,426	**4,431**	3,996
Share-based compensation		**(5)**	7	**(205)**	62
Asset retirement obligation accretion		**51**	50	**154**	140
Unrealized risk management gain		**(2)**	(2)	**(18)**	(4)
Unrealized foreign exchange (gain) loss		**(270)**	129	**418**	(323)
Realized foreign exchange gain on settlement of cross currency swaps		**—**	—	**(166)**	—
Loss from investments	7,8	**3**	68	**218**	171
Deferred income tax expense (recovery)		**91**	176	**(156)**	(1,088)
Other		**26**	(1)	**(79)**	(101)
Abandonment expenditures		**(68)**	(63)	**(197)**	(212)
Net change in non-cash working capital		**372**	(299)	**228**	(1,085)
Cash flows from operating activities		**2,070**	2,518	**3,444**	6,375
Financing activities					
Issue (repayment) of bank credit facilities and commercial paper, net	9	**68**	(1,182)	**901**	2,726
Repayment of medium-term notes	9	**(1,000)**	—	**(1,900)**	(500)
Issue of US dollar debt securities	9	**—**	—	**1,481**	—
Proceeds on settlement of cross currency swaps	16	**—**	—	**166**	—
Payment of lease liabilities	6,10	**(52)**	(64)	**(178)**	(173)
Issue of common shares on exercise of stock options		**1**	30	**36**	148
Dividends on common shares		**(502)**	(447)	**(1,448)**	(1,299)
Purchase of common shares under Normal Course Issuer Bid	12	**—**	(169)	**(271)**	(801)
Cash flows (used in) from financing activities		**(1,485)**	(1,832)	**(1,213)**	101
Investing activities					
Net proceeds (expenditures) on exploration and evaluation assets		**11**	(3)	**3**	(73)
Net expenditures on property, plant and equipment		**(714)**	(897)	**(1,836)**	(2,563)
Acquisition of Devon assets		**—**	—	**—**	(3,412)
Net change in non-cash working capital		**60**	(8)	**(362)**	(353)
Cash flows used in investing activities		**(643)**	(908)	**(2,195)**	(6,401)
(Decrease) increase in cash and cash equivalents		**(58)**	(222)	**36**	75
Cash and cash equivalents – beginning of period		**233**	398	**139**	101
Cash and cash equivalents – end of period		**$ 175**	$ 176	**$ 175**	$ 176
Interest paid on long-term debt, net		**$ 211**	$ 263	**$ 598**	$ 674
Income taxes (received) paid		**$ (101)**	$ 86	**$ (29)**	$ 372

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, 2019, except as disclosed in note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2019.

Critical Accounting Estimates and Judgements

For the three and nine months ended September 30, 2020, the novel coronavirus ("COVID-19") had an impact on the global economy, including the oil and gas industry. Business conditions in the third quarter of 2020 continued to reflect the market uncertainty associated with COVID-19, with some modest improvements to global crude oil demand and supply conditions. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions and judgements in the preparation of the unaudited interim consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Actual results may differ from estimated amounts, and those differences may be material.

Government Grants

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

2. CHANGES IN ACCOUNTING POLICIES

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

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

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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

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

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	**North Sea**	**Offshore Africa**		
Cost					
At December 31, 2019	$ 2,258	$ —	$ 69	$ 252	$ 2,579
Additions	**25**	**—**	**2**	**—**	**27**
Transfers to property, plant and equipment	**(120)**	**—**	**—**	**—**	**(120)**
Disposals/derecognitions	**(3)**	**—**	**—**	**—**	**(3)**
At September 30, 2020	**$ 2,160**	**$ —**	**$ 71**	**$ 252**	**$ 2,483**

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2019	$ 72,627	$ 7,296	$ 3,933	$ 45,016	$ 451	$ 466	$ 129,789
Additions	**663**	**88**	**64**	**999**	**5**	**16**	**1,835**
Transfers from E&E assets	**120**	**—**	**—**	**—**	**—**	**—**	**120**
Change in asset retirement obligation estimates	**(794)**	**(114)**	**(29)**	**(332)**	**(1)**	**—**	**(1,270)**
Disposals/derecognitions	**(394)**	**—**	**—**	**(358)**	**—**	**—**	**(752)**
Foreign exchange adjustments and other	**—**	**210**	**110**	**—**	**—**	**—**	**320**
At September 30, 2020	**$ 72,222**	**$ 7,480**	**$ 4,078**	**$ 45,325**	**$ 455**	**$ 482**	**$ 130,042**
Accumulated depletion and depreciation							
At December 31, 2019	$ 46,577	$ 5,712	$ 2,712	$ 6,247	$ 153	$ 345	$ 61,746
Expense	**2,682**	**189**	**115**	**1,222**	**11**	**18**	**4,237**
Disposals/derecognitions	**(394)**	**—**	**—**	**(358)**	**—**	**—**	**(752)**
Foreign exchange adjustments and other	**(28)**	**165**	**79**	**17**	**—**	**—**	**233**
At September 30, 2020	**$ 48,837**	**$ 6,066**	**$ 2,906**	**$ 7,128**	**$ 164**	**$ 363**	**$ 65,464**
Net book value							
- at September 30, 2020	**$ 23,385**	**$ 1,414**	**$ 1,172**	**$ 38,197**	**$ 291**	**$ 119**	**$ 64,578**
- at December 31, 2019	$ 26,050	$ 1,584	$ 1,221	$ 38,769	$ 298	$ 121	$ 68,043

The Company regularly reviews the business environment and commodity markets to assess the recoverability of the carrying value of its cash generating units ("CGUs"). As at September 30, 2020, the Company determined the carrying value of all of its CGUs to be recoverable.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. For the nine months ended September 30, 2020, pre-tax interest of $21 million (September 30, 2019 – $45 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.6% (September 30, 2019 – 4.0%).

Subsequent to September 30, 2020, the Company completed the acquisition of all of the issued and outstanding common shares of Painted Pony Energy Ltd. ("Painted Pony") for net cash consideration of approximately $111 million. At closing, the acquisition also included the assumption of long-term debt of approximately $397 million and certain other obligations, which will be included in the initial purchase accounting for the acquisition. Painted Pony is involved in the exploration for and development of natural gas and natural gas liquids in Northeast British Columbia.

6. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2019	$ 1,166	$ 317	$ 182	$ 124	$ 1,789
Additions	**1**	**25**	**5**	**1**	**32**
Depreciation	**(93)**	**(39)**	**(42)**	**(20)**	**(194)**
Derecognitions	**(21)**	**(4)**	**(11)**	**—**	**(36)**
Foreign exchange adjustments and other	**(1)**	**(2)**	**6**	**—**	**3**
At September 30, 2020	**$ 1,052**	**$ 297**	**$ 140**	**$ 105**	**$ 1,594**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at September 30, 2020 were as follows:

	Sep 30 2020	Dec 31 2019
Lease liabilities	**$ 1,634**	$ 1,809
Less: current portion	**189**	233
	$ 1,445	$ 1,576

Total cash outflows for leases for the three months ended September 30, 2020, including payments related to short-term leases not reported as lease assets, were $213 million (three months ended September 30, 2019 – $299 million; nine months ended September 30, 2020 – $762 million; nine months ended September 30, 2019 – $879 million). Interest expense on leases for the three months ended September 30, 2020 was $16 million (three months ended September 30, 2019 – $18 million; nine months ended September 30, 2020 – $50 million; nine months ended September 30, 2019 – $52 million).

7. INVESTMENTS

As at September 30, 2020, the Company had the following investments:

	Sep 30 2020	Dec 31 2019
Investment in PrairieSky Royalty Ltd.	**$ 188**	$ 345
Investment in Inter Pipeline Ltd.	**84**	145
	$ 272	$ 490

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Fair value loss (gain) from investments	**$ 3**	$ (20)	**$ 218**	$ (43)
Dividend income from investments	**(2)**	(7)	**(12)**	(21)
	$ 1	$ (27)	**$ 206**	$ (64)

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 September 30, 2020, the Company's investments in PrairieSky and Inter Pipeline were classified as current assets.

8. OTHER LONG-TERM ASSETS

		Sep 30 2020		Dec 31 2019
North West Redwater Partnership	**$**	**679**	$	652
Risk management (note 16)		**237**		290
Prepaid cost of service toll		**163**		130
Long-term inventory		**121**		121
Other		**103**		84
		1,303		1,277
Less: current portion		**263**		54
	$	**1,040**	$	1,223

The Company has a 50% equity investment in and has made subordinated debt advances of $679 million to NWRP, including accrued interest, subject to final adjustments. 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 17). Subsequent to COD, sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment.

The unrecognized share of the equity (income) loss from NWRP for the three months ended September 30, 2020 was a recovery of unrecognized losses of $16 million (nine months ended September 30, 2020 – unrecognized equity loss of $100 million). As at September 30, 2020, the cumulative unrecognized share of losses from NWRP was $159 million (December 31, 2019 – $59 million).

9. LONG-TERM DEBT

		Sep 30 2020		Dec 31 2019
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**2,009**	$	1,688
Medium-term notes		**2,400**		4,300
		4,409		5,988
US dollar denominated debt, unsecured				
Bank credit facilities (September 30, 2020 – US$3,941 million; December 31, 2019 – US$3,745 million)		**5,250**		4,855
Commercial paper (September 30, 2020 – US$500 million; December 31,2019 – US$254 million)		**666**		329
US dollar debt securities (September 30, 2020 – US$8,750 million; December 31, 2019 – US$7,650 million)		**11,659**		9,918
		17,575		15,102
Long-term debt before transaction costs and original issue discounts, net		**21,984**		21,090
Less: original issue discounts, net (1)		**18**		17
transaction costs (1) (2)		**90**		91
		21,876		20,982
Less: current portion of commercial paper		**666**		329
current portion of other long-term debt (1) (2)		**162**		2,062
	$	**21,048**	$	18,591

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

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

For the nine months ended September 30, 2020, the Company reported an unrealized foreign exchange loss of $392 million (September 30, 2019 – unrealized gain of $355 million) on its US dollar denominated debt.

Bank Credit Facilities and Commercial Paper

As at September 30, 2020, the Company had in place revolving bank credit facilities of $4,958 million, of which $3,771 million was available. Additionally, the Company had in place fully drawn term credit facilities of $6,738 million. Details of these facilities are described below. This excludes certain other dedicated credit facilities supporting letters of credit.

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

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

Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, US base rate or Canadian prime rate. As at September 30, 2020, the non-revolving term credit facilities were fully drawn.

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 September 30, 2020 was 1.3% (September 30, 2019 – 2.5%), and on total long-term debt outstanding for the nine months ended September 30, 2020 was 3.6% (September 30, 2019 – 4.0%).

As at September 30, 2020, letters of credit and guarantees aggregating to $473 million were outstanding.

Medium-Term Notes

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

In July 2019, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 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

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

After issuing these securities, the Company had US$1,900 million remaining on its base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2021. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

10. OTHER LONG-TERM LIABILITIES

	Sep 30 2020	Dec 31 2019
Asset retirement obligations	**$ 4,496**	$ 5,771
Lease liabilities (note 6)	**1,634**	1,809
Share-based compensation	**51**	297
Deferred purchase consideration (1)	**72**	95
Risk management (note 16)	**3**	112
Other	**97**	98
	6,353	8,182
Less: current portion	**391**	819
	$ 5,962	$ 7,363

(1) Relates to the acquisition of the Joslyn oil sands project in 2018, payable in annual installments of $25 million over the next three 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 4.8% (December 31, 2019 – 3.8%) and inflation rates of up to 2% (December 31, 2019 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Sep 30 2020	Dec 31 2019
Balance – beginning of period	**$ 5,771**	$ 3,886
Liabilities incurred	**4**	15
Liabilities (disposed) acquired, net	**(1)**	198
Liabilities settled	**(197)**	(296)
Asset retirement obligation accretion	**154**	190
Change in discount rates	**(1,270)**	1,412
Foreign exchange adjustments	**35**	(46)
Revision of cost, inflation rates and timing estimates	**—**	412
Balance – end of period	**4,496**	5,771
Less: current portion	**124**	208
	$ 4,372	$ 5,563

Share-Based Compensation

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

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

	Sep 30 2020	Dec 31 2019
Balance – beginning of period	**$ 297**	$ 124
Share-based compensation (recovery) expense	**(205)**	223
Cash payment for stock options surrendered and PSUs vested	**(36)**	(2)
Transferred to common shares	**(9)**	(53)
Charged to Oil Sands Mining and Upgrading, net	**4**	5
Balance – end of period	**51**	297
Less: current portion	**34**	227
	$ 17	$ 70

Included within share-based compensation liability as at September 30, 2020 was $24 million related to PSUs granted to certain executive employees (December 31, 2019 – $62 million).

11. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Nine Months Ended	
Expense (recovery)	**Sep 30 2020**	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Current corporate income tax – North America	**$ (59)**	$ 133	**$ (287)**	$ 374
Current corporate income tax – North Sea	**(14)**	15	**(4)**	72
Current corporate income tax – Offshore Africa	**6**	14	**12**	37
Current PRT (1) – North Sea	**(17)**	(4)	**(17)**	(89)
Other taxes	**2**	3	**4**	9
Current income tax	**(82)**	161	**(292)**	403
Deferred corporate income tax	**91**	176	**(156)**	(1,089)
Deferred PRT (1) – North Sea	**—**	—	**—**	1
Deferred income tax	**91**	176	**(156)**	(1,088)
Income tax	**$ 9**	$ 337	**$ (448)**	$ (685)

(1) Petroleum Revenue Tax

In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. Subsequent to September 30, 2020, the Government of Alberta substantively enacted legislation to accelerate this reduction, lowering the corporate tax rate from 10% to 8%, effective July 1, 2020.

12. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued common shares	Nine Months Ended Sep 30, 2020 **Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,186,857**	**$ 9,533**
Issued upon exercise of stock options	**1,169**	**36**
Previously recognized liability on stock options exercised for common shares	**—**	**9**
Purchase of common shares under Normal Course Issuer Bid	**(6,970)**	**(56)**
Balance – end of period	**1,181,056**	**$ 9,522**

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 4, 2020, the Board of Directors declared a quarterly dividend of $0.425 per common share, an increase from the previous quarterly dividend of $0.375 per common share.

Normal Course Issuer Bid

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

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

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding at September 30, 2020:

	Nine Months Ended Sep 30, 2020 **Stock options** (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**47,646**	**$ 38.04**
Granted	**11,619**	**$ 33.06**
Exercised for common shares	**(1,169)**	**$ 30.84**
Surrendered for cash settlement	**(315)**	**$ 34.04**
Forfeited	**(5,468)**	**$ 40.05**
Outstanding – end of period	**52,313**	**$ 36.90**
Exercisable – end of period	**15,596**	**$ 38.41**

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

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Sep 30 2020	Sep 30 2019
Derivative financial instruments designated as cash flow hedges	$ 75	$ 74
Foreign currency translation adjustment	49	24
	$ 124	$ 98

14. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At September 30, 2020, the ratio was within the target range at 40.3%.

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

	Sep 30 2020	Dec 31 2019
Long-term debt, net (1)	$ 21,701	$ 20,843
Total shareholders' equity	$ 32,166	$ 34,991
Debt to book capitalization	40.3%	37.3%

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

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. At September 30, 2020, the Company was in compliance with this covenant.

15. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2020	Sep 30 2019	Sep 30 2020	Sep 30 2019
Weighted average common shares outstanding – basic (thousands of shares)	1,181,046	1,185,589	1,181,701	1,193,184
Effect of dilutive stock options (thousands of shares)	441	1,533	—	2,143
Weighted average common shares outstanding – diluted (thousands of shares)	1,181,487	1,187,122	1,181,701	1,195,327
Net earnings (loss)	$ 408	$ 1,027	$ (1,184)	$ 4,819
Net earnings (loss) per common share – basic	$ 0.35	$ 0.87	$ (1.00)	$ 4.04
– diluted	$ 0.35	$ 0.87	$ (1.00)	$ 4.03

16. FINANCIAL INSTRUMENTS

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

	Sep 30, 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	**$ 1,606**	**$ —**	**$ —**	**$ —**	**$ 1,606**
Investments	**—**	**272**	**—**	**—**	**272**
Other long-term assets	**679**	**—**	**237**	**—**	**916**
Accounts payable	**—**	**—**	**—**	**(825)**	**(825)**
Accrued liabilities	**—**	**—**	**—**	**(2,112)**	**(2,112)**
Other long-term liabilities (1)	**—**	**(3)**	**—**	**(1,706)**	**(1,709)**
Long-term debt (2)	**—**	**—**	**—**	**(21,876)**	**(21,876)**
	$ 2,285	**$ 269**	**$ 237**	**$ (26,519)**	**$ (23,728)**

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

(1) Includes $1,634 million of lease liabilities (December 31, 2019 – $1,809 million) and $72 million of deferred purchase consideration payable over the next three years (December 31, 2019 – $95 million).

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

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

	Sep 30, 2020			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3** (4) (5)
Investments (3)	**$ 272**	**$ 272**	**$ —**	**$ —**
Other long-term assets	**$ 916**	**$ —**	**$ 237**	**$ 679**
Other long-term liabilities	**$ (75)**	**$ —**	**$ (3)**	**$ (72)**
Fixed rate long-term debt (6) (7)	**$ (13,951)**	**$ (15,546)**	**$ —**	**$ —**

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

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

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

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

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

(5) The fair value of NWRP subordinated debt is based on the present value of future cash receipts.

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

(7) Includes the current portion of fixed rate long-term debt.

Risk Management

The Company periodically uses derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)	**Sep 30 2020**	Dec 31 2019
Derivatives held for trading		
Natural gas AECO fixed price swaps	**$ (2)**	$ (3)
Foreign currency forward contracts	**(1)**	(10)
Natural gas AECO basis swaps	**—**	(8)
Cash flow hedges		
Foreign currency forward contracts	**62**	(91)
Cross currency swaps	**175**	290
	$ 234	$ 178
Included within:		
Current portion of other long-term assets	**$ 68**	$ 8
Current portion of other long-term liabilities	**(3)**	(112)
Other long-term assets	**169**	282
	$ 234	$ 178

For the nine months ended September 30, 2020, the ineffectiveness arising from cash flow hedges was $nil (year ended December 31, 2019 – gain of $3 million).

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

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

Asset (liability)		Sep 30 2020		Dec 31 2019
Balance – beginning of period	**$**	**178**	$	356
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**18**		(13)
Foreign exchange		**34**		(231)
Other comprehensive income		**4**		66
Balance – end of period		**234**		178
Less: current portion		**65**		(104)
	$	**169**	$	282

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

	Three Months Ended				Nine Months Ended			
		Sep 30 2020		Sep 30 2019		**Sep 30 2020**		Sep 30 2019
Net realized risk management loss (gain)	**$**	**25**	$	(1)	**$**	**9**	$	53
Net unrealized risk management gain		**(2)**		(2)		**(18)**		(4)
	$	**23**	$	(3)	**$**	**(9)**	$	49

Financial Risk Factors

a) Market risk

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

Commodity price risk management

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

At September 30, 2020, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

	Remaining term	Volume	Weighted average price	Index
Natural Gas				
AECO fixed price swaps	Oct 2020	102,500 GJ/d	$1.51	AECO

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At September 30, 2020, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

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

At September 30, 2020, the Company had the following cross currency swap contract outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swap	Oct 2020	–	Mar 2038	US$550	1.170	6.25 %	5.76 %

The cross currency swap derivative financial instrument was designated as a hedge at September 30, 2020 and was classified as a cash flow hedge.

In addition to the cross currency swap contract noted above, at September 30, 2020, the Company had US$5,009 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$4,441 million designated as cash flow hedges.

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

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At September 30, 2020, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At September 30, 2020, the Company had net risk management assets of $235 million with specific counterparties related to derivative financial instruments (December 31, 2019 – $265 million).

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

c) Liquidity risk

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

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

The maturity dates of the Company's financial liabilities were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 825	$ —	$ —	$ —
Accrued liabilities	$ 2,112	$ —	$ —	$ —
Long-term debt (1)	$ 828	$ 5,637	$ 7,224	$ 8,295
Other long-term liabilities (2)	$ 217	$ 186	$ 405	$ 901
Interest and other financing expense (3)	$ 780	$ 703	$ 1,731	$ 4,693

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

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, $189 million; one to less than two years, $161 million; two to less than five years, $383 million; and thereafter, $901 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates at September 30, 2020.

17. COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at September 30, 2020:

		Remaining 2020		2021		2022		2023		2024		Thereafter
Product transportation (1)	$	189	$	749	$	664	$	740	$	715	$	8,015
North West Redwater Partnership service toll (2)	$	41	$	164	$	152	$	161	$	160	$	2,825
Offshore vessels and equipment	$	16	$	66	$	9	$	—	$	—	$	—
Field equipment and power	$	12	$	21	$	21	$	21	$	21	$	267
Other	$	6	$	20	$	20	$	20	$	20	$	36

(1) Includes commitments pertaining to a 20-year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals. The Company may be required to reimburse certain construction costs to the service provider under certain conditions.

(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 $1,168 million of interest payable over the 30-year tolling period (note 8).

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

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

18. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2020	2019	2020	2019	2020	2019	2020	2019	2020	2019	2020	2019	2020	2019	2020	2019
Segmented product sales																
Crude oil and NGLs	2,282	2,661	5,106	6,797	81	218	313	563	122	226	228	538	2,485	3,105	5,647	7,898
Natural gas	277	199	808	823	1	9	11	45	12	16	32	52	290	224	851	920
Other income and revenue [1]	17	1	28	6	—	1	3	3	19	3	22	6	36	5	53	15
Total segmented product sales	2,576	2,861	5,942	7,626	82	228	327	611	153	245	282	596	2,811	3,334	6,551	8,833
Less: royalties	(151)	(266)	(330)	(690)	—	—	(1)	(1)	(6)	(14)	(11)	(35)	(157)	(280)	(342)	(726)
Segmented revenue	2,425	2,595	5,612	6,936	82	228	326	610	147	231	271	561	2,654	3,054	6,209	8,107
Segmented expenses																
Production	583	624	1,877	1,797	61	103	222	270	41	37	76	79	685	764	2,175	2,146
Transportation, blending and feedstock	751	793	2,367	1,893	2	5	13	15	1	—	1	1	754	798	2,381	1,909
Depletion, depreciation and amortization	937	858	2,763	2,391	41	83	216	210	68	80	136	192	1,046	1,021	3,115	2,793
Asset retirement obligation accretion	23	27	73	68	7	6	22	21	2	1	5	4	32	34	100	93
Risk management activities (commodity derivatives)	3	7	9	36	—	—	—	—	—	—	—	—	3	7	9	36
Equity loss from investments	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total segmented expenses	2,297	2,309	7,089	6,185	111	197	473	516	112	118	218	276	2,520	2,624	7,780	6,977
Segmented earnings (loss) before the following	128	286	(1,477)	751	(29)	31	(147)	94	35	113	53	285	134	430	(1,571)	1,130
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange (gain) loss																
Loss (gain) from investments																
Total non–segmented expenses																
Earnings (loss) before taxes																
Current income tax (recovery) expense																
Deferred income tax expense (recovery)																
Net earnings (loss)																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream and Refining				Inter–segment elimination and other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2020	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Segmented product sales																
Crude oil and NGLs (2)	**1,764**	3,117	**5,311**	8,707	**21**	21	**62**	62	**(68)**	81	**(33)**	336	**4,202**	6,324	**10,987**	17,003
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**48**	33	**131**	117	**338**	257	**982**	1,037
Other income and revenue (1)	**25**	1	**125**	4	**78**	—	**103**	—	**(3)**	—	**22**	—	**136**	6	**303**	19
Total segmented product sales	**1,789**	3,118	**5,436**	8,711	**99**	21	**165**	62	**(23)**	114	**120**	453	**4,676**	6,587	**12,272**	18,059
Less: royalties	**(15)**	(147)	**(55)**	(363)	**—**	—	**—**	—	**—**	—	**—**	—	**(172)**	(427)	**(397)**	(1,089)
Segmented revenue	**1,774**	2,971	**5,381**	8,348	**99**	21	**165**	62	**(23)**	114	**120**	453	**4,504**	6,160	**11,875**	16,970
Segmented expenses																
Production	**788**	784	**2,327**	2,420	**74**	4	**109**	15	**9**	14	**38**	48	**1,556**	1,566	**4,649**	4,629
Transportation, blending and feedstock (2)	**188**	357	**641**	976	**76**	—	**98**	—	**(29)**	93	**60**	398	**989**	1,248	**3,180**	3,283
Depletion, depreciation and amortization	**414**	401	**1,305**	1,192	**4**	4	**11**	11	**—**	—	**—**	—	**1,464**	1,426	**4,431**	3,996
Asset retirement obligation accretion	**19**	16	**54**	47	**—**	—	**—**	—	**—**	—	**—**	—	**51**	50	**154**	140
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**3**	7	**9**	36
Equity loss from investments	**—**	—	**—**	—	**—**	88	**—**	214	**—**	—	**—**	—	**—**	88	**—**	214
Total segmented expenses	**1,409**	1,558	**4,327**	4,635	**154**	96	**218**	240	**(20)**	107	**98**	446	**4,063**	4,385	**12,423**	12,298
Segmented earnings (loss) before the following	**365**	1,413	**1,054**	3,713	**(55)**	(75)	**(53)**	(178)	**(3)**	7	**22**	7	**441**	1,775	**(548)**	4,672
Non–segmented expenses																
Administration													**88**	95	**284**	249
Share-based compensation													**(5)**	7	**(205)**	62
Interest and other financing expense													**174**	231	**579**	619
Risk management activities (other)													**20**	(10)	**(18)**	13
Foreign exchange (gain) loss													**(254)**	115	**238**	(341)
Loss (gain) from investments													**1**	(27)	**206**	(64)
Total non-segmented expenses													**24**	411	**1,084**	538
Earnings (loss) before taxes													**417**	1,364	**(1,632)**	4,134
Current income tax (recovery) expense													**(82)**	161	**(292)**	403
Deferred income tax expense (recovery)													**91**	176	**(156)**	(1,088)
Net earnings (loss)													**408**	1,027	**(1,184)**	4,819

(1) Includes other income, the sale of diesel and other refined products, and *recoveries associated with the joint operation partners' share of the costs of lease contracts.*
(2) Includes blending and feedstock costs associated with the processing of third party bitumen and other purchased feedstock in the Oil Sands Mining and Upgrading segment.

Capital Expenditures [1]

	Nine Months Ended					
	Sep 30, 2020			Sep 30, 2019		
	Net expenditures (proceeds)	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ (5)**	**$ (93)**	**$ (98)**	$ 129	$ (185)	$ (56)
Offshore Africa	**2**	**—**	**2**	35	—	35
	$ (3)	**$ (93)**	**$ (96)**	$ 164	$ (185)	$ (21)
Property, plant and equipment						
Exploration and Production						
North America [3]	**$ 665**	**$ (1,070)**	**$ (405)**	$ 4,372	$ 915	$ 5,287
North Sea	**88**	**(114)**	**(26)**	133	104	237
Offshore Africa [4]	**64**	**(29)**	**35**	145	(1,489)	(1,344)
	817	**(1,213)**	**(396)**	4,650	(470)	4,180
Oil Sands Mining and Upgrading [5]	**999**	**(690)**	**309**	1,004	146	1,150
Midstream and Refining	**4**	**—**	**4**	9	—	9
Head office	**16**	**—**	**16**	26	(3)	23
	$ 1,836	**$ (1,903)**	**$ (67)**	$ 5,689	$ (327)	$ 5,362

(1) This table provides a reconciliation of capitalized costs, reported in note 4 and note 5, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

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

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

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

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

Segmented Assets

	Sep 30 2020	Dec 31 2019
Exploration and Production		
North America	**$ 27,931**	$ 30,963
North Sea	**1,588**	1,948
Offshore Africa	**1,474**	1,529
Other	**142**	30
Oil Sands Mining and Upgrading	**40,983**	42,006
Midstream and Refining	**1,402**	1,418
Head office	**210**	227
	$ 73,730	$ 78,121

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated July 2019. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended September 30, 2020:	
Interest coverage (times)	
Net earnings [(1)]	0.0x
Adjusted funds flow [(2)]	7.9x

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

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

This Page Left Intentionally Blank

This Page Left Intentionally Blank

This Page Left Intentionally Blank

Corporate Information

Board of Directors

Catherine M. Best, FCA, ICD.D

M. Elizabeth Cannon, O.C.

N. Murray Edwards, O.C.

Christopher L. Fong

Ambassador Gordon D. Giffin

Wilfred A. Gobert

Steve W. Laut

Tim S. McKay

Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C.

David A. Tuer

Annette M. Verschuren, O.C.

Officers

N. Murray Edwards
Executive Chairman

Tim S. McKay
President

Darren M. Fichter
Chief Operating Officer, Exploration and Production

Scott G. Stauth
Chief Operating Officer, Oil Sands

Mark A. Stainthorpe
Chief Financial Officer and Senior Vice-President, Finance

Troy J.P. Andersen
Senior Vice-President, Canadian Conventional Field Operations

Bryan C. Bradley
Senior Vice-President, Marketing

Trevor J. Cassidy
Senior Vice-President, Thermal

Allan E. Frankiw
Senior Vice-President, Production

Jay E. Froc
Senior Vice-President, Oil Sands Mining and Upgrading

Ron K. Laing
Senior Vice-President, Corporate Development and Land

Pamela A. McIntyre
Senior Vice-President, Safety, Risk Management & Innovation

Bill R. Peterson
Senior Vice-President, Development Operations

Ken W. Stagg
Senior Vice-President, Exploration

Robin S. Zabek
Senior Vice-President, Exploitation

Paul M. Mendes
Vice-President, Legal, General Counsel and Corporate Secretary

Betty Yee
Vice-President, Land

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

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

Barry Duncan
Vice-President, Finance, International

Stock Listing

Toronto Stock Exchange
Trading Symbol - CNQ

New York Stock Exchange
Trading Symbol - CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario
Computershare Investor Services LLC
New York, New York

Investor Relations

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

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