Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2020

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			Nine Months Ended	
		Sep 30 2020	Jun 30 2020	Sep 30 2019	**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)

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	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**	Three Months Ended Jun 30 2020	Three Months Ended Sep 30 2019	Nine Months Ended **Sep 30 2020**	Nine Months Ended 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

	Three Months Ended			Nine Months Ended	
($/bbl) [1]	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**Sep 30 2020**	Sep 30 2019
Production costs, excluding natural gas costs	**$ 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

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**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

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**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

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts and interest rates)	**Sep 30 2020**	Jun 30 2020	Sep 30 2019	**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**	 Jun 30 2020	 Sep 30 2019	Nine Months Ended **Sep 30 2020**	 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	Jun 30 2020	Sep 30 2019	Nine Months Ended Sep 30 2020	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.