Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS ENDED MARCH 31, 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 projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project, the timing and future operations of 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; 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 measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss), cash flows from operating activities, and cash flows used in investing activities as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP 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 measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

Special Note Regarding Currency, Financial Information and Production

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

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

The following discussion and analysis refers primarily to the Company's financial results for the three months ended March 31, 2020 in relation to the first quarter of 2019 and the fourth quarter of 2019. 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. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com. Information on the Company's website, including such guidance, does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated May 6, 2020.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Mar 31 2020**	Dec 31 2019	Mar 31 2019
Product sales [(1)]	**$ 4,652**	$ 6,335	$ 5,541
Crude oil and NGLs	**$ 4,312**	$ 5,947	$ 5,082
Natural gas	**$ 335**	$ 382	$ 456
Net earnings (loss)	**$ (1,282)**	$ 597	$ 961
Per common share – basic	**$ (1.08)**	$ 0.50	$ 0.80
– diluted	**$ (1.08)**	$ 0.50	$ 0.80
Adjusted net earnings (loss) from operations [(2)]	**$ (295)**	$ 686	$ 838
Per common share – basic	**$ (0.25)**	$ 0.58	$ 0.70
– diluted	**$ (0.25)**	$ 0.58	$ 0.70
Cash flows from operating activities	**$ 1,725**	$ 2,454	$ 996
Adjusted funds flow [(3)]	**$ 1,337**	$ 2,494	$ 2,240
Per common share – basic	**$ 1.13**	$ 2.11	$ 1.87
– diluted	**$ 1.13**	$ 2.10	$ 1.86
Cash flows used in investing activities	**$ 859**	$ 854	$ 1,029
Net capital expenditures [(4)]	**$ 838**	$ 1,056	$ 977

(1) Further details related to product sales, including 'Other' income, for the three months ended March 31, 2020 are disclosed in note 19 to the Company's unaudited interim consolidated financial statements.

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

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

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

($ millions)	Three Months Ended Mar 31 2020	Dec 31 2019	Mar 31 2019
Net earnings (loss)	***$ (1,282)***	*$ 597*	*$ 961*
Share-based compensation, net of tax (1)	***(221)***	*148*	*62*
Unrealized risk management (gain) loss, net of tax (2)	***(15)***	*16*	*13*
Unrealized foreign exchange loss (gain), net of tax (3)	***1,121***	*(225)*	*(233)*
Realized foreign exchange gain on settlement of cross currency swaps (4)	***(166)***	*—*	*—*
Loss from investments, net of tax (5) (6)	***268***	*150*	*35*
Adjusted net earnings (loss) from operations	***$ (295)***	*$ 686*	*$ 838*

(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 ("Redwater Partnership") 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 the Redwater Partnership's equity 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).

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

($ millions)	Three Months Ended Mar 31 2020	Dec 31 2019	Mar 31 2019
Cash flows from operating activities	***$ 1,725***	*$ 2,454*	*$ 996*
Net change in non-cash working capital	***(595)***	*(52)*	*1,016*
Abandonment expenditures (1)	***89***	*84*	*108*
Other (2)	***118***	*8*	*120*
Adjusted funds flow	***$ 1,337***	*$ 2,494*	*$ 2,240*

(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 first quarter of 2020 was $1,282 million compared with net earnings of $961 million for the first quarter of 2019 and net earnings of $597 million for the fourth quarter of 2019. The net loss for the first quarter of 2020 included net after-tax expenses of $987 million compared with net after-tax income of $123 million for the first quarter of 2019 and net after-tax expenses of $89 million for the fourth quarter of 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, and loss from investments. Excluding these items, the adjusted net loss from operations for the first quarter of 2020 was $295 million compared with adjusted net earnings from operations of $838 million for the first quarter of 2019 and an adjusted net earnings from operations of $686 million for the fourth quarter of 2019.

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

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

The impacts of share-based compensation, risk management activities and the impact of fluctuations in foreign exchange rates on long-term debt outstanding at period end also contributed to the movements in net earnings (loss). These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the first quarter of 2020 were $1,725 million compared with $996 million for the first quarter of 2019 and $2,454 million for the fourth quarter of 2019. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors noted above relating to the fluctuations in net earnings (loss) and adjusted net earnings (loss) from operations (excluding the effect of depletion, depreciation and amortization), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the first quarter of 2020 was $1,337 million compared with $2,240 million for the first quarter of 2019 and $2,494 million for the fourth quarter of 2019. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

Production Volumes

Total production before royalties for the first quarter of 2020 increased 14% to 1,178,752 BOE/d from 1,035,212 BOE/d for the first quarter of 2019 and was comparable with 1,156,276 BOE/d for the fourth quarter of 2019. 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)		**Mar 31 2020**		Dec 31 2019		Sep 30 2019		Jun 30 2019
Product sales [1]	**$**	**4,652**	$	6,335	$	6,587	$	5,931
Crude oil and NGLs	**$**	**4,312**	$	5,947	$	6,324	$	5,597
Natural gas	**$**	**335**	$	382	$	257	$	324
Net earnings (loss)	**$**	**(1,282)**	$	597	$	1,027	$	2,831
Net earnings (loss) per common share								
– basic	**$**	**(1.08)**	$	0.50	$	0.87	$	2.37
– diluted	**$**	**(1.08)**	$	0.50	$	0.87	$	2.36

($ millions, except per common share amounts)		Mar 31 2019		Dec 31 2018		Sep 30 2018		Jun 30 2018
Product sales [1]	$	5,541	$	3,831	$	6,327	$	6,389
Crude oil and NGLs	$	5,082	$	3,327	$	5,967	$	6,071
Natural gas	$	456	$	504	$	360	$	318
Net earnings (loss)	$	961	$	(776)	$	1,802	$	982
Net earnings (loss) per common share								
– basic	$	0.80	$	(0.64)	$	1.48	$	0.80
– diluted	$	0.80	$	(0.64)	$	1.47	$	0.80

(1) Further details related to product sales, including 'Other' income, for the three months ended March 31, 2020 are disclosed in note 19 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 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, disposition and revaluation of properties and gains/losses on investments** – Fluctuations due to the recognition of the acquisition, disposition and revaluation 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 the Redwater Partnership.
- **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 quarter of 2020 due to the erosion of global demand, reflecting the severity of COVID-19 and related economic conditions. Additionally, global crude oil pricing has been impacted by OPEC and Russia increasing crude oil supply into the market. These conditions have had a corresponding impact on the realized prices the Company received for its crude oil and NGLs products in the first quarter of 2020. Subsequent to quarter end, in April 2020, WTI benchmark pricing averaged US$16.70 per bbl and the WCS Heavy Differential averaged US$13.20 per bbl.

Production Flexibility and Cost Control

The Company continues to be nimble and has acted 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 has optimized the production profile across its diverse asset base in the current business environment. The Company has also implemented changes to its compensation program in light of current commodity volatility, and these changes are expected to have an immediate impact on the Company's costs in the second quarter of 2020. The Company is also working diligently to reduce production costs wherever possible, asking all stakeholders to contribute to the sustainability of operations.

During periods of low commodity pricing, the Company's focus shifts to optimization of its significant long life low decline assets, including the Oil Sands Mining and Upgrading assets that have a reserve life in excess of 43 years. Low decline assets, including high value SCO, comprise 77% of forecasted 2020 liquids production and will continue to be a key focus of the Company at current commodity price levels.

Production costs in the first 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 Wolf Lake 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.

Liquidity

As at March 31, 2020, the Company had in place revolving bank credit facilities of $4,959 million, of which $3,921 million was available. Including cash and cash equivalents and other liquidity, the Company had approximately $5,000 million in available liquidity. Subsequent to quarter end, the Company's $750 million non-revolving term credit facility, originally due February 2021, was increased by $250 million to $1,000 million and extended to February 2022.

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 March 2020, as a result of the volatility in crude oil pricing, the Company reduced its 2020 capital spending budget to approximately $2,960 million. Subsequent to quarter end, 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

	Three Months Ended		
(Average for the period)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
WTI benchmark price (US$/bbl)	**$ 46.08**	$ 56.96	$ 54.90
Dated Brent benchmark price (US$/bbl)	**$ 50.42**	$ 62.64	$ 63.34
WCS Heavy Differential from WTI (US$/bbl)	**$ 20.47**	$ 15.84	$ 12.38
SCO price (US$/bbl)	**$ 43.39**	$ 56.32	$ 52.19
Condensate benchmark price (US$/bbl)	**$ 45.54**	$ 52.99	$ 50.49
Condensate Differential from WTI (US$/bbl)	**$ 0.54**	$ 3.97	$ 4.40
NYMEX benchmark price (US$/MMBtu)	**$ 1.95**	$ 2.50	$ 3.16
AECO benchmark price (C$/GJ)	**$ 2.03**	$ 2.21	$ 1.84
US/Canadian dollar average exchange rate (US$)	**$ 0.7434**	$ 0.7576	$ 0.7522

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 timing of program cessation remains uncertain. 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 should curtailment restrictions ease.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$46.08 per bbl for the first quarter of 2020, a decrease of 16% from US$54.90 per bbl for the first quarter of 2019, and a decrease of 19% from US$56.96 per bbl for the fourth quarter of 2019.

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$50.42 per bbl for the first quarter of 2020, a decrease of 20% from US$63.34 per bbl for the first quarter of 2019, and a decrease of 20% from US$62.64 per bbl for the fourth quarter of 2019.

The decrease in WTI and Brent pricing for the first quarter of 2020 from the comparable periods primarily reflected significant reductions in refinery utilization due to decreased demand as a result of COVID-19. Additionally, global crude oil pricing has been impacted by OPEC and Russia increasing crude oil supply into the market.

The WCS Heavy Differential averaged US$20.47 per bbl for the first quarter of 2020, an increase of 65% from US$12.38 per bbl for the first quarter of 2019, and an increase of 29% from US$15.84 per bbl for the fourth quarter of 2019. The widening of the WCS Heavy Differential for the first quarter of 2020 from the comparable periods primarily reflected constrained egress capacity.

The SCO price averaged US$43.39 per bbl for the first quarter of 2020, a decrease of 17% from US$52.19 per bbl for the first quarter of 2019, and a decrease of 23% from US$56.32 per bbl for the fourth quarter of 2019. The decrease in SCO pricing for the first quarter of 2020 from the comparable periods primarily reflected a decrease in WTI benchmark pricing.

NYMEX natural gas pricing averaged US$1.95 per MMBtu for the first quarter of 2020, a decrease of 38% from US$3.16 per MMBtu for the first quarter of 2019 and a decrease of 22% from US$2.50 per MMBtu for the fourth quarter of 2019. The decrease in NYMEX natural gas pricing for the first quarter of 2020 from the comparable periods primarily reflected increased production levels in North America and the impact of seasonal weather conditions.

AECO natural gas pricing averaged $2.03 per GJ for the first quarter of 2020, an increase of 10% from $1.84 per GJ for the first quarter of 2019 and a decrease of 8% from $2.21 per GJ for the fourth quarter of 2019. The increase in AECO natural gas pricing for the first quarter of 2020 from the first quarter of 2019 primarily reflected additional egress capability. The decrease in AECO natural gas pricing for the first quarter of 2020 from the fourth quarter of 2019 primarily reflected seasonal demand factors and lower export prices.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**456,877**	506,571	319,437
North America – Oil Sands Mining and Upgrading (1)	**438,101**	357,856	416,206
North Sea	**27,755**	30,860	25,714
Offshore Africa	**15,943**	18,495	22,155
	938,676	913,782	783,512
Natural gas (MMcf/d)			
North America	**1,407**	1,411	1,454
North Sea	**23**	25	28
Offshore Africa	**10**	19	28
	1,440	1,455	1,510
Total barrels of oil equivalent (BOE/d)	**1,178,752**	1,156,276	1,035,212
Product mix			
Light and medium crude oil and NGLs	**11%**	12%	14%
Pelican Lake heavy crude oil	**5%**	5%	6%
Primary heavy crude oil	**7%**	8%	7%
Bitumen (thermal oil)	**20%**	23%	9%
Synthetic crude oil (1)	**37%**	31%	40%
Natural gas	**20%**	21%	24%
Percentage of gross revenue (1) (2) (excluding Midstream and Refining revenue)			
Crude oil and NGLs	**92%**	94%	91%
Natural gas	**8%**	6%	9%

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

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

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**414,460**	438,894	281,233
North America – Oil Sands Mining and Upgrading	**432,936**	340,262	397,639
North Sea	**27,693**	30,815	25,675
Offshore Africa	**15,296**	17,294	20,260
	890,385	827,265	724,807
Natural gas (MMcf/d)			
North America	**1,374**	1,351	1,399
North Sea	**23**	25	28
Offshore Africa	**10**	18	25
	1,407	1,394	1,452
Total barrels of oil equivalent (BOE/d)	**1,124,839**	1,059,562	966,758

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 first quarter of 2020 increased 20% to average a record 938,676 bbl/d from 783,512 bbl/d for the first quarter of 2019, and increased 3% from 913,782 bbl/d for the fourth quarter of 2019. The increase in crude oil and NGLs production for the first quarter of 2020 from the first quarter of 2019 primarily reflected the impact of production from the acquisition of thermal and heavy oil assets from Devon. The increase in production for the first quarter of 2020 from the fourth quarter of 2019 primarily reflected high utilization rates and reliable operations in Oil Sands Mining and Upgrading following a strong ramp up at Horizon after the successful completion of the turnaround in the fourth quarter of 2019 and the completion of the proactive piping replacement in January 2020, offsetting the impact of mandatory Government of Alberta curtailment by optimizing higher value SCO production volumes. While optimizing production volumes across the asset base, the Company achieved maximum allowable production under the Government of Alberta curtailment guidelines during the first quarter of 2020.

Natural gas production before royalties for the first quarter of 2020 of 1,440 MMcf/d decreased 5% from 1,510 MMcf/d for the first quarter of 2019, and was comparable with 1,455 MMcf/d for the fourth quarter of 2019. The decrease in natural gas production for the first quarter of 2020 from the first quarter of 2019 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the first quarter of 2020 increased 43% to average 456,877 bbl/d from 319,437 bbl/d for the first quarter of 2019, and decreased 10% from 506,571 bbl/d for the fourth quarter of 2019. The increase in crude oil and NGLs production for the first quarter of 2020 from the first quarter of 2019 primarily reflected the impact of production from the acquisition of thermal and heavy oil assets from Devon. The decrease in production from the fourth quarter of 2019 was primarily due to the Company's optimization of higher value SCO production during mandatory Government of Alberta curtailment.

Thermal oil production before royalties for the first quarter of 2020 increased 142% to 228,303 bbl/d from 94,146 bbl/d for the first quarter of 2019, and decreased 12% from 259,387 bbl/d for the fourth quarter of 2019. The increase in thermal oil production for the first quarter of 2020 from the first quarter of 2019 primarily reflected the impact of production from the acquisition of thermal and heavy oil assets from Devon, together with new production from Kirby North and pad additions at Primrose. The decrease in thermal oil production from the fourth quarter of 2019 primarily reflected the optimization of curtailment volumes across the Company's asset base that resulted in increased production volumes of higher value SCO, and planned turnaround activities at Jackfish during the first quarter of 2020, which were successfully completed in mid-April 2020.

Pelican Lake heavy crude oil production before royalties decreased 5% to 57,986 bbl/d in the first quarter of 2020 from 61,240 bbl/d in the first quarter of 2019, and was comparable with 59,013 bbl/d in the fourth quarter of 2019, reflecting the field's low natural decline rate.

Natural gas production before royalties for the first quarter of 2020 decreased 3% to 1,407 MMcf/d from 1,454 MMcf/d for the first quarter of 2019, and was comparable with 1,411 MMcf/d for the fourth quarter of 2019. The decrease in natural gas production for the first quarter of 2020 from the first quarter of 2019 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the first quarter of 2020 increased 5% to average 438,101 bbl/d from 416,206 bbl/d for the first quarter of 2019 and increased 22% from 357,856 bbl/d for the fourth quarter of 2019. The increase in SCO production for the first quarter of 2020 from the comparable periods was due to high utilization rates and reliable operations following a strong ramp up at Horizon after the successful completion of the turnaround in the fourth quarter of 2019 and the completion of the proactive piping replacement in January 2020. Production reflected the Company's optimization of higher value SCO production during mandatory Government of Alberta curtailment.

North Sea

North Sea crude oil production before royalties for the first quarter of 2020 increased 8% to 27,755 bbl/d from 25,714 bbl/d for the first quarter of 2019 and decreased 10% from 30,860 bbl/d for the fourth quarter of 2019. The increase in production for the first quarter of 2020 from the first quarter of 2019 primarily reflected the impact of added production from the 2019 drilling program, partially offset by natural field declines. The decrease in production for the first quarter of 2020 from the fourth quarter of 2019 primarily reflected natural field declines.

Offshore Africa

Offshore Africa crude oil production before royalties for the first quarter of 2020 decreased 28% to 15,943 bbl/d from 22,155 bbl/d for the first quarter of 2019 and decreased 14% from 18,495 bbl/d for the fourth quarter of 2019. The decrease in production for the first quarter of 2020 from the comparable periods primarily reflected planned turnaround activities at Espoir and 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)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
North Sea	**—**	344,726	851,919
Offshore Africa	**532,347**	519,504	1,055,383
	532,347	864,230	1,907,302

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 25.90**	$ 49.60	$ 53.98
Transportation	**3.87**	3.53	3.26
Realized sales price, net of transportation	**22.03**	46.07	50.72
Royalties	**2.34**	6.03	5.95
Production expense	**13.71**	12.46	16.04
Netback	**$ 5.98**	$ 27.58	$ 28.73
Natural gas ($/Mcf) (1)			
Sales price (2)	**$ 2.22**	$ 2.64	$ 3.09
Transportation	**0.46**	0.43	0.46
Realized sales price, net of transportation	**1.76**	2.21	2.63
Royalties	**0.05**	0.11	0.12
Production expense	**1.31**	1.17	1.33
Netback	**$ 0.40**	$ 0.93	$ 1.18
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	**$ 21.90**	$ 39.20	$ 39.27
Transportation	**3.50**	3.24	3.06
Realized sales price, net of transportation	**18.40**	35.96	36.21
Royalties	**1.70**	4.37	3.78
Production expense	**11.87**	10.79	12.68
Netback	**$ 4.83**	$ 20.80	$ 19.75

(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		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 23.48**	$ 46.06	$ 50.92
North Sea	**$ 45.85**	$ 87.76	$ 87.61
Offshore Africa	**$ 58.16**	$ 70.73	$ 81.00
Average	**$ 25.90**	$ 49.60	$ 53.98
Natural gas ($/Mcf) (1) (2)			
North America	**$ 2.15**	$ 2.52	$ 2.88
North Sea	**$ 3.75**	$ 5.10	$ 10.05
Offshore Africa	**$ 8.94**	$ 8.58	$ 7.34
Average	**$ 2.22**	$ 2.64	$ 3.09
Average ($/BOE) (1) (2)	**$ 21.90**	$ 39.20	$ 39.27

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

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

North America

North America realized crude oil prices averaged $23.48 per bbl for the first quarter of 2020, a decrease of 54% compared with $50.92 per bbl for the first quarter of 2019 and a decrease of 49% compared with $46.06 per bbl for the fourth quarter of 2019. The decrease in realized crude oil prices for the first quarter of 2020 from the comparable periods was primarily due to lower WTI benchmark pricing together with the widening of the WCS Heavy Differential due to constrained egress capacity. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2020, contributed approximately 137,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 25% to average $2.15 per Mcf for the first quarter of 2020 compared with $2.88 per Mcf for the first quarter of 2019, and decreased 15% compared with $2.52 per Mcf for the fourth quarter of 2019. The decrease in realized natural gas prices for the first quarter of 2020 from the comparable periods primarily reflected increased production levels in North America, seasonal demand factors, and lower export prices.

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

	Three Months Ended		
(Quarterly average)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 38.15**	$ 47.32	$ 49.13
Pelican Lake heavy crude oil ($/bbl)	**$ 27.75**	$ 51.66	$ 56.28
Primary heavy crude oil ($/bbl)	**$ 25.01**	$ 49.72	$ 52.27
Bitumen (thermal oil) ($/bbl)	**$ 16.53**	$ 42.93	$ 48.27
Natural gas ($/Mcf)	**$ 2.15**	$ 2.52	$ 2.88

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

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

North Sea

North Sea realized crude oil prices decreased 48% to average $45.85 per bbl for the first quarter of 2020 from $87.61 per bbl for the first quarter of 2019 and decreased 48% from $87.76 per bbl for the fourth quarter of 2019. Realized crude oil prices per barrel in any particular period are dependent on the terms of the various sales contracts, the frequency and timing from liftings of 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 first quarter of 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 28% to average $58.16 per bbl for the first quarter of 2020 from $81.00 per bbl for the first quarter of 2019 and decreased 18% from $70.73 per bbl for the fourth quarter of 2019. 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 first quarter of 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		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 2.49**	$ 6.52	$ 6.22
North Sea	**$ 0.10**	$ 0.13	$ 0.13
Offshore Africa	**$ 2.36**	$ 4.60	$ 6.93
Average	**$ 2.34**	$ 6.03	$ 5.95
Natural gas ($/Mcf) (1)			
North America	**$ 0.05**	$ 0.11	$ 0.11
Offshore Africa	**$ 0.51**	$ 0.39	$ 0.85
Average	**$ 0.05**	$ 0.11	$ 0.12
Average ($/BOE) (1)	**$ 1.70**	$ 4.37	$ 3.78

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

North America

North America crude oil and natural gas royalties for the first quarter of 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 11% of product sales for the first quarter of 2020 compared with 12% for the first quarter of 2019 and 14% for the fourth quarter of 2019. The decrease in royalty rates for the first quarter of 2020 from the comparable periods was primarily due to lower benchmark prices together with fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 2% of product sales for the first quarter of 2020 compared with 4% for the first quarter of 2019 and the fourth quarter of 2019. The decrease in royalty rates for the first quarter of 2020 from the comparable periods was primarily due to lower benchmark pricing.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 4% for the first quarter of 2020, compared with 9% of product sales for the first quarter of 2019 and 6% for the fourth quarter of 2019. Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs ($/bbl) [(1)]			
North America	**$ 12.69**	$ 10.74	$ 15.07
North Sea	**$ 29.73**	$ 33.67	$ 39.68
Offshore Africa	**$ 11.88**	$ 16.75	$ 9.79
Average	**$ 13.71**	$ 12.46	$ 16.04
Natural gas ($/Mcf) [(1)]			
North America	**$ 1.24**	$ 1.11	$ 1.30
North Sea	**$ 3.45**	$ 3.25	$ 2.41
Offshore Africa	**$ 5.56**	$ 3.19	$ 2.12
Average	**$ 1.31**	$ 1.17	$ 1.33
Average ($/BOE) [(1)]	**$ 11.87**	$ 10.79	$ 12.68

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

North America

North America crude oil and NGLs production expense for the first quarter of 2020 of $12.69 per bbl decreased 16% from $15.07 per bbl for the first quarter of 2019 and increased 18% from $10.74 per bbl for the fourth quarter of 2019. The decrease in production expense per bbl for the first quarter of 2020 from the first quarter of 2019 primarily reflected the impact of operating cost synergies captured to date combined with added production from the acquisition of assets from Devon, Kirby North and pad additions at Primrose. The increase in production expense per bbl for the first quarter of 2020 from the fourth quarter of 2019 primarily reflected the impact of seasonal conditions, lower sales volumes, and higher energy costs, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base.

North America natural gas production expense for the first quarter of 2020 of $1.24 per Mcf decreased 5% from $1.30 per Mcf for the first quarter of 2019 and increased 12% from $1.11 per Mcf for the fourth quarter of 2019. The decrease in production expense per Mcf for the first quarter of 2020 from the first quarter of 2019 primarily reflected the Company's continued focus on cost control and increased volumes processed in strategically owned and operated infrastructure. The increase in production expense per Mcf for the first quarter of 2020 from the fourth quarter of 2019 primarily reflected the impact of seasonal conditions and higher energy costs, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base.

North Sea

North Sea crude oil production expense for the first quarter of 2020 decreased 25% to $29.73 per bbl from $39.68 per bbl for the first quarter of 2019 and decreased 12% from $33.67 per bbl for the fourth quarter of 2019. The decrease in production expense per bbl for the first quarter of 2020 from the comparable periods primarily reflected reduced maintenance activities due to COVID-19 in the first quarter of 2020. The decrease in production expense per bbl from the first quarter of 2019 also reflected the impact of higher production volumes in the first quarter of 2020. North Sea production expense also reflected fluctuations in the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the first quarter of 2020 increased 21% to $11.88 per bbl from $9.79 per bbl for the first quarter of 2019 and decreased 29% from $16.75 per bbl for the fourth quarter of 2019. The increase in production expense per bbl for the first quarter of 2020 from the first quarter of 2019 was primarily due to decreased production volumes, reflecting natural field declines. The decrease in production expense per bbl for the first quarter of 2020 from the fourth quarter of 2019 was primarily due to the timing of liftings from various fields that have different cost structures, partially offset by lower production volumes in the first quarter of 2020.

Crude oil production expense in Offshore Africa for the first quarter of 2020 and comparable periods also reflected fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Expense	**$ 1,095**	$ 1,083	$ 843
$/BOE (1)	**$ 15.75**	$ 14.98	$ 15.54

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

Depletion, depreciation and amortization expense for the first quarter of 2020 of $15.75 per BOE was comparable with $15.54 per BOE for the first quarter of 2019 and increased 5% from $14.98 per BOE for the fourth quarter of 2019.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Expense	**$ 35**	$ 36	$ 28
$/BOE (1)	**$ 0.50**	$ 0.49	$ 0.54

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

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

Asset retirement obligation accretion expense for the first quarter of 2020 of $0.50 per BOE decreased 7% from $0.54 per BOE for the first quarter of 2019 and was comparable with $0.49 per BOE for the fourth quarter of 2019. 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 sites. Production in the first quarter of 2020 was strong and averaged 438,101 bbl/d due to high utilization rates and reliable operations following a strong ramp up at Horizon after the successful completion of the turnaround in the fourth quarter of 2019 and the completion of the proactive piping replacement in January 2020. Production reflected the Company's optimization of higher value SCO production during mandatory Government of Alberta curtailment.

The Company achieved production costs of $809 million for the first quarter of 2020, a 5% decrease from $856 million for the fourth quarter of 2019. The decrease in production costs on a total and per barrel basis demonstrated the Company's continued focus on efficiencies and cost control.

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

	Three Months Ended		
($/bbl) [1]	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
SCO realized sales price [2]	**$ 50.88**	$ 68.67	$ 65.86
Bitumen value for royalty purposes [3]	**$ 16.82**	$ 44.88	$ 48.16
Bitumen royalties [4]	**$ 0.87**	$ 3.47	$ 2.31
Transportation	**$ 1.28**	$ 1.33	$ 1.17

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

(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 $50.88 per bbl for the first quarter of 2020, a decrease of 23% from $65.86 per bbl for the first quarter of 2019 and a decrease of 26% from $68.67 per bbl for the fourth quarter of 2019. The decrease in the realized SCO sales price for the first quarter of 2020 from the comparable periods primarily reflected movements in WTI benchmark pricing.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 19 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended		
($ millions)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Production costs	**$ 809**	$ 856	$ 822
Less: costs incurred during turnaround periods	**—**	(71)	—
Adjusted production costs	**$ 809**	$ 785	$ 822
Adjusted production costs, excluding natural gas costs	**$ 773**	$ 743	$ 779
Natural gas costs	**36**	42	43
Adjusted production costs	**$ 809**	$ 785	$ 822

	Three Months Ended		
($/bbl) [1]	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Adjusted production costs, excluding natural gas costs	**$ 19.83**	$ 21.79	$ 20.33
Natural gas costs	**0.93**	1.23	1.13
Adjusted production costs	**$ 20.76**	$ 23.02	$ 21.46
Sales (bbl/d)	**428,515**	370,468	425,790

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

Production costs for the first quarter of 2020 averaged $20.76 per bbl, a decrease of 3% from $21.46 per bbl for the first quarter of 2019 and a decrease of 10% from $23.02 per bbl for the fourth quarter of 2019. The decrease in production costs per bbl for the first quarter of 2020 from the comparable periods primarily reflected higher utilization rates following a strong ramp up at Horizon after the successful completion of the turnaround in the fourth quarter of 2019 and the completion of the proactive piping replacement in January 2020. The Company continued to focus on efficiencies and cost control to proactively mitigate the impact of the decline in commodity pricing.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Expense	**$ 440**	$ 464	$ 417
Less: depreciation incurred during turnaround periods	**—**	(46)	—
Adjusted depletion, depreciation and amortization	**$ 440**	$ 418	$ 417
$/bbl (1)	**$ 11.28**	$ 12.25	$ 10.88

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

Depletion, depreciation and amortization expense for the first quarter of 2020 increased 4% to $11.28 per bbl from $10.88 per bbl for the first quarter of 2019 and decreased 8% from $12.25 per bbl for the fourth quarter of 2019. The decrease in depletion, depreciation and amortization expense per bbl for the first quarter of 2020 from the fourth quarter of 2019 was primarily due to the impact of the proactive piping replacement in the fourth quarter of 2019.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Expense	**$ 17**	$ 14	$ 16
$/bbl (1)	**$ 0.44**	$ 0.44	$ 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 of $0.44 per bbl for the first quarter of 2020 increased 7% from $0.41 per bbl for the first quarter of 2019 and compared with $0.44 per bbl for the fourth quarter of 2019. Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended Mar 31 2020	Dec 31 2019	Mar 31 2019
Revenue	**$ 21**	$ 26	$ 21
Less:			
Production expense	**6**	5	6
Depreciation	**4**	3	3
Equity loss from investment	**—**	73	60
Segment earnings (loss) before taxes	**$ 11**	$ (55)	$ (48)

The Company has a 50% interest in the Redwater Partnership. Redwater Partnership has entered into agreements to construct, and after constructed, will operate a 50,000 bbl/d bitumen upgrader and refinery (the "Project") under processing agreements that target 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 ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing synthetic crude oil into refined products. In the first quarter of 2020, the Project continued to operate as a light oil refinery and will continue to process synthetic crude oil into refined products until the heavy oil units can reliably commence commercial processing of bitumen. Design modifications to the reactor burners in the gasifier unit continued through the first quarter of 2020. As at March 31, 2020, the total estimate of capital costs incurred for the Project, net of margins from pre-commercial sales, was approximately $10 billion.

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. As at March 31, 2020, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $229 million, for a Company total of $668 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay this portion of the cost of service tolls over the 30-year tolling period. As at March 31, 2020, the Company had recognized $148 million in prepaid cost of service tolls (December 31, 2019 – $130 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis and matures in February 2021. As at March 31, 2020, Redwater Partnership had borrowings of $2,786 million under the credit facility.

During the fourth quarter of 2019, the carrying value of the Redwater Partnership investment was reduced to $nil. The unrecognized share of losses from the Redwater Partnership for the three months ended March 31, 2020 was $93 million (March 31, 2019 – recognized equity loss of $60 million). As at March 31, 2020, the cumulative unrecognized share of losses from the Redwater Partnership was $152 million (December 31, 2019 – $59 million). The unrecognized share of losses for the three months ended March 31, 2020 primarily reflected the impact of Redwater Partnership deferring cost of service toll revenue until it achieves commercial operations and is reliably processing toll payers' bitumen.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended **Mar 31 2020**	Dec 31 2019	Mar 31 2019
Expense	**$ 108**	$ 95	$ 70
$/BOE [(1)]	**$ 1.00**	$ 0.90	$ 0.76

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

Administration expense for the first quarter of 2020 of $1.00 per BOE increased 32% from $0.76 per BOE for the first quarter of 2019 and increased 11% from $0.90 per BOE for the fourth quarter of 2019. Administration expense per BOE increased for the first quarter of 2020 from the comparable periods primarily due to the impact of higher personnel costs, including those related to the acquisition of assets from Devon.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended **Mar 31 2020**	Dec 31 2019	Mar 31 2019
(Recovery) expense	**$ (223)**	$ 161	$ 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 $223 million share-based compensation recovery for the first quarter of 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 first quarter of 2020 was $7 million related to PSUs granted to certain executive employees (March 31, 2019 – $10 million expense). For the first quarter of 2020, the Company charged $1 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (March 31, 2019 – $1 million charged).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended **Mar 31 2020**	Dec 31 2019	Mar 31 2019
Expense, gross	**$ 214**	$ 225	$ 211
Less: capitalized interest	**8**	8	20
Expense, net	**$ 206**	$ 217	$ 191
$/BOE [(1)]	**$ 1.90**	$ 2.04	$ 2.06
Average effective interest rate	**3.9%**	3.9%	4.1%

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

Capitalized interest of $8 million for the first quarter of 2020 was related to residual project activities at Horizon.

Net interest and other financing expense per BOE for the first quarter of 2020 decreased 8% to $1.90 per BOE from $2.06 per BOE for the first quarter of 2019 and decreased 7% from $2.04 per BOE for the fourth quarter of 2019. The decrease in interest expense per BOE for the first quarter of 2020 from the first quarter of 2019 primarily reflected higher sales volumes in the first quarter of 2020.The decrease in interest expense per BOE for the first quarter of 2020 from the fourth quarter of 2019 was primarily due to lower average debt levels.

The Company's average effective interest rate for the first quarter of 2020 decreased from the first quarter of 2019 primarily due to the impact of lower benchmark interest rates on the Company's outstanding bank credit facilities.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended		
($ millions)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Foreign currency contracts	**$ (57)**	$ 5	$ —
Natural gas financial instruments	**10**	6	(1)
Crude oil and NGLs financial instruments	**—**	—	28
Realized (gain) loss	**(47)**	11	27
Foreign currency contracts	**(9)**	10	9
Natural gas financial instruments	**(8)**	7	—
Crude oil and NGLs financial instruments	**—**	—	5
Unrealized (gain) loss	**(17)**	17	14
Net (gain) loss	**$ (64)**	$ 28	$ 41

During the first quarter of 2020, the net realized risk management gains were related to the settlement of foreign currency contracts. The Company recorded a net unrealized gain of $17 million ($15 million after-tax) on its risk management activities for the first quarter of 2020 (three months ended December 31, 2019 – unrealized loss of $17 million; $16 million after-tax; three months ended March 31, 2019 – unrealized loss of $14 million; $13 million after-tax).

Further details related to outstanding derivative financial instruments at March 31, 2020 are disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended		
($ millions)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Net realized gain	**$ (199)**	$ (4)	$ (6)
Net unrealized loss (gain)	**1,121**	(225)	(233)
Net loss (gain) (1)	**$ 922**	$ (229)	$ (239)

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

The net realized foreign exchange gain for the first quarter of 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 quarter. The net unrealized foreign exchange loss for the first quarter of 2020 was primarily related to the impact of a weaker Canadian dollar with respect to outstanding US dollar debt. The net unrealized loss (gain) for each of the periods presented reflected the impact of the cross currency swaps, including the settlement of US$500 million in cross currency swaps during the first quarter of 2020 (three months ended March 31, 2020 – unrealized loss of $74 million, December 31, 2019 – unrealized loss of $29 million, March 31, 2019 – unrealized loss of $30 million). The US/Canadian dollar exchange rate at March 31, 2020 was US$0.7082 (December 31, 2019 – US$0.7713, March 31, 2019 – US$0.7485).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Mar 31 2020**	Dec 31 2019	Mar 31 2019
North America [1]	**$ (194)**	$ (20)	$ 163
North Sea	**9**	40	29
Offshore Africa	**4**	7	12
PRT [2] – North Sea	**—**	—	(42)
Other taxes	**2**	4	3
Current income tax (recovery) expense	**(179)**	31	165
Deferred income tax expense	**20**	194	94
	$ (159)	$ 225	$ 259
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**36%**	26%	26%

(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 first quarter of 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 first quarter of 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.

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

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Mar 31 2020**	 Dec 31 2019	 Mar 31 2019
Exploration and Evaluation			
Net property (dispositions) acquisitions	**$ (18)**	$ —	$ 1
Net expenditures	**25**	—	32
Total Exploration and Evaluation	**7**	—	33
Property, Plant and Equipment			
Net property acquisitions	**13**	20	24
Well drilling, completion and equipping	**202**	169	254
Production and related facilities	**214**	238	287
Capitalized interest and other	**12**	15	29
Net expenditures	**441**	442	594
Total Exploration and Production	**448**	442	627
Oil Sands Mining and Upgrading			
Project costs	**56**	121	76
Sustaining capital	**201**	334	140
Turnaround costs	**23**	57	8
Capitalized interest and other	**9**	9	10
Total Oil Sands Mining and Upgrading	**289**	521	234
Midstream and Refining	**1**	1	2
Abandonments [2]	**89**	84	108
Head office	**11**	8	6
Total net capital expenditures	**$ 838**	$ 1,056	$ 977
By segment			
North America	**$ 395**	$ 330	$ 524
North Sea	**26**	63	36
Offshore Africa	**27**	49	67
Oil Sands Mining and Upgrading	**289**	521	234
Midstream and Refining	**1**	1	2
Abandonments [2]	**89**	84	108
Head office	**11**	8	6
Total	**$ 838**	$ 1,056	$ 977

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

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

	Three Months Ended		
($ millions)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Cash flows used in investing activities	***$ 859***	*$ 854*	*$ 1,029*
Net change in non-cash working capital	***(110)***	*118*	*(160)*
Abandonment expenditures (1)	***89***	*84*	*108*
Net capital expenditures	***$ 838***	*$ 1,056*	*$ 977*

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

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

Net capital expenditures for the first quarter of 2020 were $838 million compared with $977 million for the first quarter of 2019 and $1,056 million for the fourth quarter of 2019.

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 March 2020, as a result of the volatility in crude oil pricing, the Company reduced its 2020 capital spending budget to approximately $2,960 million. Subsequent to quarter end, the budget was further reduced to approximately $2,680 million, a $1,370 million reduction from the original 2020 budget.

The Company's ability to be nimble in a changing environment was evident as flexibility was utilized by drilling 10 fewer crude oil and bitumen wells than originally budgeted.

Drilling Activity (1)

	Three Months Ended		
(number of wells)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Net successful natural gas wells	**11**	4	8
Net successful crude oil wells (2)	**35**	12	30
Dry wells	**—**	—	1
Stratigraphic test / service wells	**367**	89	332
Total	**413**	105	371
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	97%

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

(2) Includes bitumen wells.

North America

During the first quarter of 2020, the Company targeted 11 net natural gas wells, 6 net primary heavy crude oil wells, 6 net bitumen (thermal oil) wells and 22 net light crude oil wells.

North Sea

During the first quarter of 2020, the Company completed 1 gross light crude oil well (1.0 on a net basis) in the North Sea.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Working capital (1)	**$ 683**	$ 241	$ 319
Long-term debt (2) (3)	**$ 22,687**	$ 20,982	$ 20,990
Less: cash and cash equivalents	**1,071**	139	90
Long-term debt, net	**$ 21,616**	$ 20,843	$ 20,900
Share capital	**$ 9,517**	$ 9,533	$ 9,358
Retained earnings	**23,425**	25,424	22,852
Accumulated other comprehensive income	**320**	34	58
Shareholders' equity	**$ 33,262**	$ 34,991	$ 32,268
Debt to book capitalization (3) (4)	**39.4%**	37.3%	39.3%
Debt to market capitalization (3) (5)	**48.7%**	29.5%	32.2%
After-tax return on average common shareholders' equity (6)	**9.4%**	16.1%	9.2%
After-tax return on average capital employed (3) (7)	**6.8%**	10.9%	6.6%

(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 fair value adjustments, 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 March 31, 2020, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Business Environment" section of this MD&A and in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2019. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. 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 the Company's borrowing capacity:
  - Borrowings under the non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at March 31, 2020, the non-revolving term credit facilities were fully drawn.
  - Subsequent to March 31, 2020, the $750 million non-revolving term credit facility, originally due February 2021, was extended to February 2022 and increased to $1,000 million.
  - Each of the $2,425 million revolving syndicated credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - In July 2019, the Company filed new base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, expiring 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.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages.

As at March 31, 2020, the Company had in place revolving bank credit facilities of $4,959 million, of which $3,921 million was available. Additionally, the Company had in place fully drawn term credit facilities of $6,650 million. Including cash and cash equivalents and other liquidity, the Company had approximately $5,000 million in available liquidity. This excludes certain other dedicated credit facilities supporting letters of credit.

As at March 31, 2020, the Company had total US dollar denominated debt with a carrying amount of $15,994 million (US$11,327 million), before transaction costs and original issue discounts. This included $5,968 million (US$4,227 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$3,677 million). The fixed repayment amount of these hedging instruments is $5,700 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $268 million to $15,726 million as at March 31, 2020.

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

Net long-term debt was $21,616 million at March 31, 2020, resulting in a debt to book capitalization ratio of 39.4% (December 31, 2019 – 37.3%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities are greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at March 31, 2020 are discussed in note 10 of the Company's unaudited interim consolidated financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at March 31, 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 March 31, 2020, 102,500 GJ/d of currently forecasted natural gas volumes were hedged using AECO fixed price swaps for April 2020 to October 2020. Further details related to the Company's commodity derivative financial instruments outstanding at March 31, 2020 are discussed in note 17 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)	$	2,803	$	1,869	$	10,087	$	8,031
Other long-term liabilities (2)	$	250	$	188	$	412	$	971
Interest and other financing expense (3)	$	900	$	829	$	1,849	$	5,071

(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, $221 million; one to less than two years, $163 million; two to less than five years, $391 million; and thereafter, $971 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 March 31, 2020.

Share Capital

As at March 31, 2020, there were 1,180,854,000 common shares outstanding (December 31, 2019 – 1,186,857,000 common shares) and 56,202,000 stock options outstanding. As at May 5, 2020, the Company had 1,180,854,000 common shares outstanding and 55,989,000 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.

For the three months ended March 31, 2020, the Company purchased for cancellation 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 March 31, 2020:

		Remaining 2020		2021		2022		2023		2024		Thereafter
Product transportation (1)	$	563	$	733	$	641	$	728	$	701	$	7,911
North West Redwater Partnership service toll (2)	$	113	$	168	$	162	$	160	$	154	$	2,828
Offshore vessels and equipment	$	57	$	70	$	10	$	—	$	—	$	—
Field equipment and power	$	24	$	21	$	20	$	21	$	20	$	249
Other	$	19	$	20	$	17	$	17	$	17	$	29

(1) Includes commitments pertaining to a 20 year 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 portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the cost of service tolls is $1,222 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.

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 judgments related to the preparation of financial statements. The Company prospectively adopted the amendments on January 1, 2020.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. For the three months ended March 31, 2020, COVID-19 had an impact on the global economy, including the oil and gas industry. 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. 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 three months ended March 31, 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.