FIRST QUARTER | 2020

REPORT TO SHAREHOLDERS FOR THE PERIOD ENDED MARCH 31, 2020

Report to Shareholders for the period ended March 31, 2020

(All financial figures are expressed in Canadian dollars ($ or C$) unless otherwise noted)

MEG Energy Corp. reported first quarter 2020 operational and financial results on May 4, 2020.

MEG continues to respond proactively to the safety and financial challenges associated with the COVID-19 pandemic.

"We are committed to ensuring the health and safety of all our personnel and the safe and reliable operation of the Christina Lake facility" said Derek Evans, President and Chief Executive Officer. "The current business environment demands swift, decisive actions to enhance MEG's already strong financial liquidity position. To that end, we are reducing production to minimum levels and advancing the planned plant turnaround, cutting capital by $100 million versus original guidance, and reducing non-energy operating cost and G&A guidance by $20 million and $10 million, respectively."

MEG remains well positioned from a financial liquidity perspective, benefiting not only from its significant 2020 hedge book, the term and structure of its outstanding indebtedness and credit facility but also from the low decline, low cost structure of its high-quality Christina Lake asset.

First quarter financial and operating highlights include:

- Free cash flow of $24 million driven by adjusted funds flow of $78 million ($0.26 per share) and disciplined capital spend of $54 million;
- MEG exited the first quarter with $62 million of cash on hand. Based on the current commodity price environment, MEG does not expect this level of cash on hand to materially change in the second quarter of 2020;
- Bitumen production volumes of 91,557 barrels per day (bbls/d) at a steam-oil-ratio (SOR) of 2.31;
- Net operating costs of $5.51 per barrel, including non-energy operating costs of $4.57 per barrel and strong power sales which had the impact of offsetting 70% of per barrel energy operating costs resulting in a net energy operating cost of $0.94 per barrel;
- MEG utilized cash on hand to repay an additional $132 million of long-term debt concurrent with the refinancing of US$1.2 billion of existing indebtedness announced January 16, 2020. The combination of these transactions is neutral to ongoing cash costs and results in no outstanding debt maturities before 2024;
- Realized commodity price risk management gain of $106 million. At current strip pricing the full year 2020 value of MEG's commodity price risk management hedge positions, including the $106 million realized gain, is estimated at $525 million, providing strong financial liquidity through the remainder of the year;
- On March 10, 2020, MEG reduced its full year 2020 capital investment by 20% to $200 million from original guidance of $250 million. Notwithstanding the Corporation's strong hedge position, in light of the current weak oil price environment and MEG's focus on maintaining its financial liquidity, MEG is further reducing full year 2020 capital investment by an additional $50 million to $150 million, or 40% below original guidance and reducing non-energy operating cost and general and administrative ("G&A") expense by $20 million and $10 million respectively; and
- Subsequent to quarter end, a decision was made to roll back salaries across the company, with an emphasis on Board, executive and senior leader compensation. Effective June 1, 2020, Board members will receive a 25% cash compensation reduction. The President and Chief Executive Officer will have his annual base salary reduced by 25%, the Chief Operating Officer and Chief Financial Officer will each take a 15% annual base salary reduction,

vice presidents will receive a 12% annual base salary rollback and all other employees will receive a 7.5% annual base salary rollback. In addition, the value of the 2020 long-term incentive awards issued to employees and directors on April 1 was reduced by 20% compared to 2019 levels.

Blend Sales Pricing and North American Market Access

MEG realized an average AWB blend sales price of US$27.12 per barrel during the three months ended March 31, 2020 compared to US$42.83 per barrel in Q4 2019. The reduction in average AWB blend sales price quarter over quarter was primarily a result of the average WTI price decreasing by US$10.79 per barrel combined with the average WTI:AWB differential at Edmonton widening by US$4.34 per barrel. MEG sold 23% (21% via pipe and 2% via rail) of its sales volumes to the US Gulf Coast ("USGC") in the first quarter of 2020 compared to 34% (28% via pipe and 6% via rail) in the fourth quarter of 2019. The reduction in sales to the USGC in the first quarter is a result of substantially all rail sales in the first quarter being sold freight on board ("FOB") at rail terminals at Edmonton, and 50% apportionment on the Enbridge mainline in the first quarter compared to 45% in the fourth quarter of 2019.

Transportation and storage costs averaged US$4.39 per barrel of AWB blend sales in the first quarter of 2020 compared to US$5.69 per barrel of AWB blend sales in the fourth quarter of 2019. The quarter over quarter reduction in transportation and storage costs is primarily due to the suspension of delivered rail contracts to refiners in January 2020 in favour of FOB rail contracts at Edmonton entered into during the fourth quarter of 2019, combined with improved rail facility utilization. MEG's AWB blend sales by rail increased to 30,152 bbls/d (27,867 bbls/d FOB Edmonton) in the first quarter of 2020 from 17,111 bbls/d (8,675 bbls/d FOB Edmonton) in the fourth quarter of 2019. The increase in first quarter 2020 rail sales was a direct result of fourth quarter 2019 rail contracting to allow MEG to take advantage of the Alberta Government's Special Production Allowance program for curtailed producers announced October 2019.

Excluding transportation and storage costs upstream of the Edmonton index sales point, MEG's net AWB blend sales price at Edmonton averaged US$24.55 per barrel during the three months ended March 31, 2020 compared to the posted AWB index price at Edmonton of US$23.39 per barrel. Notwithstanding that Enbridge mainline apportionment averaged 50% during the first quarter of 2020, MEG was able to capture pricing better than the Edmonton index as a result of its marketing and storage assets and the ability to move barrels to the higher-priced USGC market.

Operational Performance

Bitumen production averaged 91,557 bbls/d in the first quarter of 2020, compared to 94,566 bbls/d in the fourth quarter of 2019. Bitumen production in the first quarter was impacted by a combination of extreme cold weather in January, scheduled planned maintenance activities in February and implementation of the COVID-19 response plan in March which resulted in a significant reduction in operating personnel on site, which impacted production levels. Net operating costs in the first quarter of 2020 averaged $5.51 per barrel, a 6% decrease compared to the fourth quarter of 2019, directly impacted by higher sales revenues from surplus power from MEG's cogeneration facilities. Non-energy operating costs averaged $4.57 per barrel compared to $4.49 per barrel in the fourth quarter of 2019. Net energy operating costs averaged just $0.94 per barrel in the first quarter of 2020.

G&A expense was $16 million, or $1.96 per barrel of production, in the first quarter of 2020 compared to $20 million, or $2.25 per barrel of production, in the fourth quarter of 2019. The decrease in aggregate G&A quarter over quarter is a result of the Corporation continuing to drive efficiency gains into its operations.

Adjusted Funds Flow and Net Loss

MEG's bitumen realization averaged $19.45 per barrel in the first quarter of 2020 compared to $46.86 per barrel in the fourth quarter of 2019. The reduction in average bitumen realization quarter over quarter was driven by the same factors that drove the reduction in average AWB blend sales price. In addition, the widening WTI:AWB differential also resulted in a lower recovery of the cost of diluent through blend sales, which increased the Corporation's cost of diluent.

The decline in bitumen realization was the largest contributing factor to the 41% decline in MEG's cash operating netback. The lower cash operating netback drove a decrease in the Corporation's adjusted funds flow from $157 million in the fourth quarter of 2019 to $78 million in the first quarter of 2020.

The Corporation recognized a net loss of $284 million in the first quarter of 2020 compared to net earnings of $26 million in the fourth quarter of 2019. The decrease is due to decreased bitumen realization combined with a number of non-cash charges, including an unrealized foreign exchange loss of $267 million, an exploration expense of $366 million associated with certain non-core growth properties and an inventory impairment charge of $29 million partially offset by a $429 million unrealized gain on commodity risk management contracts.

Capital Expenditures

Capital expenditures in the first quarter of 2020 totaled $54 million compared to $72 million in the fourth quarter of 2019. Of the $54 million incurred in the first quarter, approximately $40 million was directed towards sustaining and maintenance activities and $13 million towards the brownfield project at MEG's Phase 2B central processing facility.

COVID-19 Global Pandemic

The Corporation is continually monitoring and responding to the ongoing evolving COVID-19 situation. The Corporation's business activities have been declared an essential service by the Alberta Government and the Corporation remains committed to the health and safety of all personnel and to the safety and continuity of operations. The Corporation has established a COVID-19 task force, comprised of senior management and employees as well as third party expert consultants to promptly implement measures to protect the health and safety of the Corporation's work force and the public, as well as to ensure continuity of operations. The Corporation is monitoring daily developments in the COVID-19 outbreak and actions taken by government authorities in response thereto. In accordance with the guidance of provincial and federal health officials and to limit the risk and transmission of COVID-19, the Corporation has implemented mandatory self-quarantine policies, travel restrictions, enhanced cleaning and sanitation measures, and social distancing measures, including directing the vast majority of its office staff and certain non-essential field staff to work from home. Only location essential personnel are currently working at the Corporation's Christina Lake site and Calgary head office. The Corporation believes that it can maintain safe operations with these pandemic-related procedures and protocols in place. Additionally, in order to prevent and/or minimize any COVID-19 outbreak at its Christina Lake site, the Corporation has implemented additional measures as part of its pandemic response, including changes to crew size and shift durations, screening measures prior to allowing employees and contractors on to the Corporation's Christina Lake site (or flights departing to the Christina Lake site), and mandating the use of masks and other measures to work to ensure continued safe and reliable operations.

Outlook

Since early March 2020 global crude oil prices have experienced multi-decade lows coupled with extreme levels of volatility driven primarily by the unprecedented demand shock due to COVID-19. Notwithstanding MEG's strong financial liquidity driven by its estimated $525 million full year 2020 hedge book, MEG is further reducing its 2020 full year capital budget to $150 million from the previously revised level of $200 million, of which $125 million will be directed toward sustaining and maintenance activities, including approximately $25 million related to major plant turnaround activities at the Corporation's Phase 1 & 2 facilities scheduled to begin in early June 2020. Relative to the original budget, the turnaround is expected to be longer in duration, with completion expected in August, while being undertaken at a lower total cash cost by relying more heavily on internal resources. This will allow the Corporation to take advantage of the current low oil price environment by reducing turnaround requirements in 2021. The remainder of the revised capital budget will be directed primarily towards regulatory, corporate and other.

MEG currently expects first half 2020 production to average approximately 76,000 bbls/d. In light of the current oil price environment, the Corporation is suspending full year 2020 production guidance. At present, MEG expects to produce approximately 30,000 bbls/d during the Phase 1 & 2 turnaround. This production volume reflects the minimum production level required to maintain the integrity of its operations and reservoir performance at the Phase 2B facility, which has current productive capacity of approximately 60,000 bbls/d. During the turnaround, if oil prices improve from current levels, MEG will have the ability to efficiently produce up to this 60,000 bbls/d level. Upon completion of the turnaround activities at MEG's Phase 1 & 2 facilities in August, MEG will determine, based on the oil price environment at that time, when to bring these facilities back into operation. Irrespective of actual production levels in the second half of 2020, which will be a function of the oil price environment as we move through the year, based on full year $150 million capital investment for 2020, the Corporation will have the ability to achieve production levels in excess of 80,000 bbls/d post turnaround, once Phase 1 & 2 are brought back into operation.

In consideration of the significant impact COVID-19 is having on the Corporation's bitumen realizations, MEG has taken further steps to reduce its 2020 full year non-energy operating costs and G&A expense. Non-energy operating costs are now targeted at $140 - $150 million, which is $20 million, or approximately 12%, lower than original guidance. G&A is now targeted at $52.5 - $55 million, which is $10 million, or approximately 16%, lower than original guidance. The majority of these cost reductions were a result of a reduction in staffing levels and rationalization of ongoing administrative costs. Targeted 2020 G&A expense is approximately $15 million, or 20%, lower than actual 2019 G&A expense, and approximately $30 million, or 35%, lower than 2018 G&A expense.

Guidance Update

Summary of 2020 Guidance	**Revised Guidance (May 4, 2020)**	**Previously Revised Guidance (March 10, 2020)**	**Original Guidance (November 21, 2019)**
Production (1H20)	76,000 bbls/d	N/A	N/A
Production (FY20 average)	N/A	93,000 - 95,000 bbls/d	94,000 - 97,000 bbls/d
Non-energy operating cost	$140 - $150 million	$155 - $165 million ($4.50 - $4.90 per barrel)	$160 - $170 million ($4.50 - $4.90 per barrel)
G&A expense	$52.5 - $55 million	$60 - $62.5 million ($1.75 - $1.85 per barrel)	$62.5 - $65 million ($1.75 - $1.85 per barrel)
Capital expenditures	$150 million	$200 million	$250 million

Financial Liquidity

MEG exited the first quarter with $62 million of cash on hand after making a debt repayment of $132 million in the quarter. Based on the current commodity price environment, MEG does not expect this level of cash on hand to materially change in the second quarter of 2020.

The Corporation's earliest maturing long-term debt is four years out, represented by US$600 million of senior unsecured notes due March 2024. None of the Corporation's outstanding long-term debt contain financial maintenance covenants. Additionally, MEG's modified covenant-lite $800 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $400 million. If drawn in excess of $400 million, MEG is required to maintain a quarterly first lien net leverage ratio (first lien net debt to last twelve-month EBITDA) of 3.5 or less. Under MEG's credit facility, first lien net debt is calculated as debt under the credit facility plus other debt that is secured on a *pari passu* basis with the credit facility, less cash on hand.

2020 Commodity Hedges

For the second quarter of 2020, MEG has entered into benchmark WTI fixed price swaps for approximately 66,100 bbls/d of bitumen production at an average price of US$57.75 per barrel. The table below reflects all of MEG's current 2020 financial and physical hedge positions. At current strip pricing, MEG's financial hedge book is expected to add $525 million to full year 2020 adjusted funds flow, including the $106 million realized gain in the first quarter.

	Forecast Period			
	Q2 2020	Q3 2020	Q4 2020	2020
WTI Hedges				
WTI Fixed Price Hedges				
Volume (bbls/d)	66,103	29,043	16,887	**46,234**
Weighted average fixed WTI price (US$/bbl)	$ 57.75	$ 50.08	$ 59.36	**$ 57.06**
Enhanced WTI Fixed Price Hedges with Sold Put Options(1)				
Volume (bbls/d)	—	16,870	24,500	**10,342**
Weighted average fixed WTI price (US$/bbl)/Put option strike price (US$/bbl)	—	$59.38 / $52.00	$59.11 / $52.00	**$59.22 / $52.00**
Total WTI hedge volume (bbls/d)	**66,103**	**45,913**	**41,387**	**56,576**
WTI:WCS Differential Hedges				
Volume(2) (bbls/d)	42,448	34,150	41,150	**36,974**
Weighted average fixed WTI:WCS differential at Edmonton (US$/bbl)	$ (18.43)	$ (19.48)	$ (19.38)	**$ (19.29)**
Condensate Hedges				
Volume(3) (bbls/d)	21,936	23,208	23,208	**21,875**
Average % of WTI landed in Edmonton	105%	104%	103%	**105%**

(1) Includes fixed price swap and sold put options entered into for the second half of 2020. At an average 2H20 WTI price of US$52.00 per barrel or higher, MEG's effective WTI hedge price for 2H20 is US$56.21 per barrel. Illustratively, at an average 2H20 WTI price of US$30.00 per barrel, MEG's effective WTI hedged price for 2H20 is US$45.78 per barrel.

(2) 2020 includes approximately 12,000 bbls/d of physical forward rail blend sales at a fixed WTI:AWB differential.

(3) 2020 includes approximately 7,200 bbls/d (annual average) of physical forward condensate purchases. Where applicable, the average % of WTI landed in Edmonton includes estimated net transportation costs to Edmonton.

ADVISORY

Forward-Looking Information

This quarterly report contains forward-looking information and should be read in conjunction with the "Forward-Looking Information" contained within the Advisory section of this quarter's Management Discussion and Analysis and Press Release.

Non-GAAP Measures

Certain financial measures in this report to shareholders including free cash flow and cash operating netback are non-GAAP measures. These terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Free Cash Flow

Free cash flow is presented to assist management and investors in analyzing performance by the Corporation as a measure of financial liquidity and the capacity of the business to repay debt. Free cash flow is calculated as adjusted funds flow less capital expenditures.

	Three months ended March 31	
($millions)	**2020**	**2019**
Net cash provided by (used in) operating activities	**$ 99**	$ (69)
Net change in non-cash operating working capital items	**(30)**	220
Funds flow from (used in) operations	**69**	151
Adjustments:		
Contract cancellation	**7**	—
Decommissioning expenditures	**2**	—
Adjusted funds flow	**$ 78**	$ 151
Capital expenditures	**(54)**	(53)
Free cash flow	**$ 24**	$ 98

Cash Operating Netback

Cash operating netback is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to fund future capital expenditures. The Corporation's cash operating netback is calculated by deducting the related cost of diluent, blend purchases, transportation and storage, third- party curtailment credits, operating expenses, royalties and realized commodity risk management gains or losses from blend sales and power revenue. The per barrel calculation of cash operating netback is based on bitumen sales volume.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three-month period ended March 31, 2020 was approved by the Corporation's Audit Committee on May 4, 2020. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three-month period ended March 31, 2020, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2019, the 2019 annual MD&A and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in millions of Canadian dollars, except where otherwise indicated.

Unless otherwise indicated, all per barrel figures are based on bitumen sales volumes.

MD&A - Table of Contents

1. BUSINESS DESCRIPTION

MEG is an energy company focused on sustainable in situ thermal oil production in the southern Athabasca region of Alberta, Canada. MEG is actively developing innovative enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods to improve the responsible economic recovery of oil as well as lower carbon emissions. MEG transports and sells its thermal oil production to refiners throughout North America and internationally.

MEG owns a 100% working interest in over 750 square miles of mineral leases. In the report prepared by GLJ Petroleum Consultants Ltd. ("GLJ") and effective December 31, 2019, GLJ estimated that the leases it had evaluated contained approximately 2.1 billion barrels of gross proved plus probable ("2P") bitumen reserves at the Christina Lake Project. For information regarding MEG's estimated reserves contained in the report prepared by GLJ, please refer to the Corporation's most recently filed AIF, which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

Beginning in early March 2020, market events and conditions, including global excess crude oil supply primarily due to an unprecedented reduction in global demand due to the COVID-19 pandemic, have caused significant degradation and volatility in global commodity prices. With the rapid spread of COVID-19 and excess crude oil supply, the price of crude oil and other petroleum products has deteriorated significantly and is expected to remain volatile until there is better visibility on the timing of the return to a more stable economic environment.

The Corporation is continually monitoring and responding to the ongoing evolving COVID-19 situation. The Corporation's business activities have been declared an essential service by the Alberta Government and the Corporation remains committed to the health and safety of all personnel and to the safety and continuity of operations. The Corporation has established a COVID-19 task force, comprised of senior management and employees as well as third party expert consultants to promptly implement measures to protect the health and safety of the Corporation's work force and the public, as well as to ensure continuity of operations. The Corporation is monitoring daily developments in the COVID-19 outbreak and actions taken by government authorities in response thereto. In accordance with the guidance of provincial and federal health officials and to limit the risk and transmission of COVID-19, the Corporation has implemented mandatory self-quarantine policies, travel restrictions, enhanced cleaning and sanitation measures, and social distancing measures, including directing the vast majority of its office staff and certain non-essential field staff to work from home. Only location essential personnel are currently working at the Corporation's Christina Lake site and Calgary head office. The Corporation believes that it can maintain safe operations with these pandemic-related procedures and protocols in place. Additionally, in order to prevent and/or minimize any COVID-19 outbreak at its Christina Lake site, the Corporation has implemented additional measures as part of its pandemic response, including changes to crew size and shift durations, screening measures prior to allowing employees and contractors on to the Corporation's Christina Lake site (or flights departing to the Christina Lake site), and mandating the use of masks and other measures to ensure continued safe and reliable operations.

Adjusted funds flow in the first quarter of 2020 was $78 million compared to $151 million in the first quarter of 2019, a 48% decrease, reflecting a lower cash operating netback of $16.83 per barrel in the first quarter of 2020 compared to $29.80 per barrel in the first quarter of 2019. The significant decrease in cash operating netback was attributable to a lower blend sales price which was driven by an acute decline in global crude oil prices beginning early March 2020 as markets experienced multi–decade lows coupled with extreme levels of volatility primarily as a result of the unprecedented demand shock due to COVID–19. Blend sales price declines were partially offset by realized gains of $106 million, or $11.97 per barrel, on commodity risk management contracts in place during the period.

Bitumen production averaged 91,557 bbls/d during the first quarter of 2020 compared to 87,113 bbls/d during the first quarter of 2019. A slow easing of government mandated curtailment through 2019 has resulted in the Corporation's production increasing by 5% between the first quarter of 2019 and the first quarter of 2020.

The Corporation recognized a net loss of $284 million in the first quarter of 2020 compared to a net loss of $48 million in the first quarter of 2019. The increase in the net loss is due to the decreased cash operating netback as well as other non-cash charges. The Corporation recognized an unrealized foreign exchange loss of $267 million, an exploration expense of $366 million related to non-core growth properties and an inventory impairment of $29 million partially offset by a $429 million unrealized gain on commodity risk management contracts.

On January 31, 2020, the Corporation successfully closed a private offering of $1.6 billion (US$1.2 billion) in aggregate principal amount of 7.125% senior unsecured notes due February 2027. On February 18, 2020, the net proceeds of the offering, together with cash on hand, were used to fully redeem $1 billion (US$800 million) in aggregate principal amount of 6.375% senior unsecured notes due January 2023 and partially redeem $530 million (US$400 million) of the US$1.0 billion aggregate principal amount of 7.0% senior unsecured notes due March 2024. Concurrent with the private offering, the Corporation redeemed $132 million (US$100 million) in aggregate principal amount of its 6.5% senior secured second lien notes due January 2025. Cash on hand was used to fund this senior secured second lien notes partial redemption.

On March 10, 2020, the Corporation reduced its full year 2020 capital investment by 20% to $200 million from original guidance of $250 million. Notwithstanding the Corporation's strong hedge position, in light of the current weak oil price environment and the Corporation's focus on maintaining its financial liquidity, the Corporation is further reducing full year 2020 capital investment by an additional $50 million to $150 million, or 40% below original guidance and reducing non-energy operating costs and general and administrative expense ("G&A") by $20 million and $10 million, respectively.

The following table summarizes selected operational and financial information of the Corporation for the periods noted. All dollar amounts are stated in Canadian dollars ($ or C$) unless otherwise noted and all per barrel figures are based on bitumen sales volumes:

	2020			**2019**			**2018**	
($millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Bitumen production - bbls/d	**91,557**	94,566	93,278	97,288	87,113	87,582	98,751	71,325
Steam-oil ratio	**2.31**	2.27	2.26	2.16	2.20	2.22	2.17	2.22
Bitumen sales - bbls/d	**97,214**	94,347	94,992	95,120	89,822	88,283	93,856	74,418
Bitumen realization - $/bbl	**19.45**	46.86	53.37	62.23	50.21	15.31	49.63	47.33
Net operating costs - $/bbl[1]	**5.51**	5.87	4.30	4.66	6.17	4.55	4.34	5.64
Non-energy operating costs - $/bbl	**4.57**	4.49	4.22	4.53	5.22	4.25	4.38	5.47
Cash operating netback - $/bbl[2]	**16.83**	28.33	32.44	37.88	29.80	7.14	24.01	18.66
Adjusted funds flow[3]	**78**	157	192	227	151	(37)	116	18
Per share, diluted	**0.26**	0.51	0.63	0.76	0.50	(0.13)	0.39	0.06
Revenue	**665**	992	958	1,062	919	520	803	689
Net earnings (loss)	**(284)**	26	24	(64)	(48)	(199)	118	(179)
Per share, diluted	**(0.95)**	0.09	0.08	(0.21)	(0.16)	(0.67)	0.39	(0.61)
Capital expenditures	**54**	72	40	32	53	144	139	191
Cash and cash equivalents	**62**	206	154	399	154	318	373	564
Long-term debt - C$	**3,212**	3,123	3,257	3,582	3,660	3,740	3,544	3,607
Long-term debt - US$	**2,275**	2,409	2,459	2,737	2,740	2,741	2,742	2,745

(1) *Net operating costs include energy and non-energy operating costs, reduced by power revenue.*

(2) *Cash operating netback is a non-GAAP measure and does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Refer to the "NON-GAAP MEASURES" section of this MD&A.*

(3) *Refer to Note 19 of the interim consolidated financial statements for further details.*

3. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended March 31	
	2020	**2019**
Bitumen production – bbls/d	**91,557**	87,113
Steam-oil ratio (SOR)	**2.31**	2.20

Bitumen Production

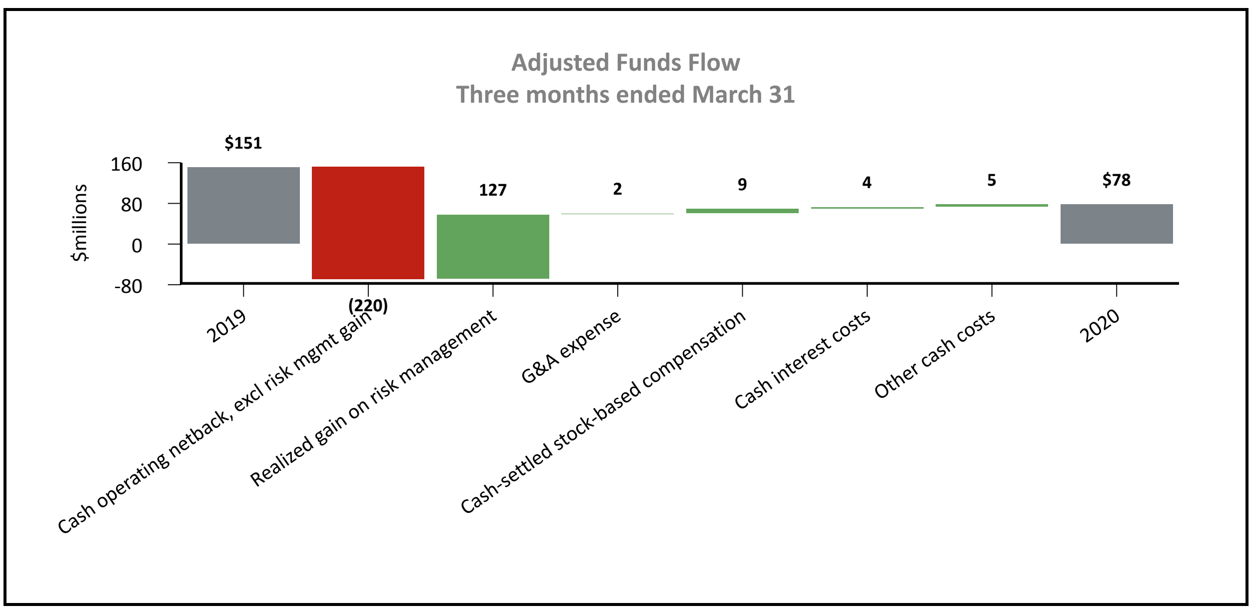
Bitumen production averaged 91,557 bbls/d during the first quarter of 2020 compared to 87,113 bbls/d during the same period of 2019. A slow easing of government mandated curtailment through 2019 has resulted in the Corporation's production increasing by 5% between the first quarter of 2019 and the first quarter of 2020.

Steam-Oil Ratio

The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is Steam-Oil Ratio ("SOR"). SOR is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The Corporation continues to focus on improving efficiency of production through a lower SOR, which generally indicates that steam is being more efficiently used but is also influenced by the introduction of new wells into circulation. The SOR increased for the three months ended March 31, 2020 compared to the same period of 2019 due to the timing of new well pairs and wells being brought into steam circulation and production.

Adjusted Funds Flow

During the three months ended March 31, 2020, adjusted funds flow decreased compared to the same period of 2019, primarily driven by the Corporation's reduced cash operating netback during the three months ended March 31, 2020. Cash operating netback during the first quarter of 2020 was significantly impacted by a sharp decline in global crude oil prices predominantly associated with the COVID–19 global pandemic, which was partially mitigated by realized gains on commodity risk management contracts.



Net cash provided by operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as net cash provided by operating activities excluding the net change in non-cash operating working capital, items not considered part of ordinary continuing operating results, and decommissioning expenditures. Adjusted funds flow is used by management to analyze the Corporation's operating performance and cash flow generating ability. By excluding changes in non-cash working capital and other adjustments from cash flows, the adjusted funds flow measure provides a meaningful metric for management by establishing a clear link between the Corporation's cash flows and the cash operating netback.

The following table reconciles cash provided by operating activities to adjusted funds flow:

	Three months ended March 31	
($millions)	**2020**	**2019**
Net cash provided by (used in) operating activities	**$ 99**	$ (69)
Net change in non-cash operating working capital items	**(30)**	220
Funds flow from (used in) operations	**69**	151
Adjustments:		
Contract cancellation	**7**	—
Decommissioning expenditures	**2**	—
Adjusted funds flow	**$ 78**	$ 151

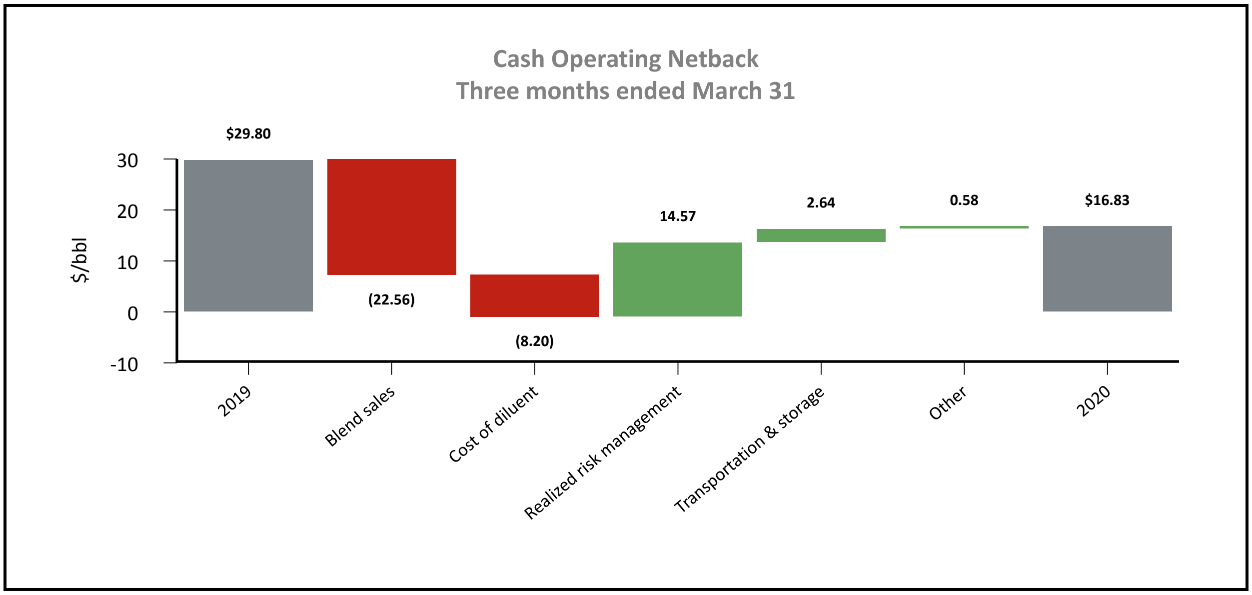
Cash Operating Netback

The following table summarizes the Corporation's cash operating netback. Unless otherwise indicated, the per barrel calculation for the period indicated below are based on bitumen sales volume.

	Three months ended March 31			
	2020		2019	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	**$ 469**		$ 696	
Sales from purchased product[1]	**179**		203	
Petroleum revenue	**648**		899	
Purchased product	**(176)**		(196)	
Blend sales[2]	**472**	**36.46**	703	59.02
Cost of diluent	**(300)**	**(17.01)**	(297)	(8.81)
Bitumen realization	**172**	**19.45**	406	50.21
Transportation and storage[3]	**(77)**	**(8.63)**	(91)	(11.27)
Third-party curtailment credits[4]	**2**	**0.18**	—	—
Royalties	**(6)**	**(0.63)**	(3)	(0.37)
Net operating costs	**(48)**	**(5.51)**	(49)	(6.17)
Cash operating netback - excluding realized commodity risk management	**43**	**4.86**	263	32.40
Realized gain (loss) on commodity risk management	**106**	**11.97**	(21)	(2.60)
Cash operating netback[5]	**$ 149**	**$ 16.83**	$ 242	$ 29.80
Bitumen sales volumes - bbls/d		**97,214**		89,822

(1) *Sales from purchased oil products related to marketing asset optimization activities.*
(2) *Blend sales per barrel are based on blend sales volumes.*
(3) *Defined as transportation and storage expense less transportation revenue. Transportation and storage includes costs associated with moving the Corporation's blend from Christina Lake to a final sales location and optimizing the timing of delivery, net of third-party recoveries on diluent transportation arrangements.*
(4) *The Corporation can purchase or sell production curtailment credits to either increase its production, or sell excess production capacity, compared to its provincially-mandated curtailment level.*
(5) *A non-GAAP measure as defined in the "NON-GAAP MEASURES" section of this MD&A.*

Blend sales includes net revenue related to marketing asset optimization activities focused on the recovery of fixed costs related to any marketing assets during periods of underutilization of such assets, with the goal to strengthen cash operating netback. Asset optimization activities consist of the purchase and sale of third-party products. The Corporation does not engage in speculative trading. The purchase and sale of third-party products requires the concurrent locking in of price risk pursuant to policies approved by the Corporation's Board of Directors which can be achieved either through the counterparty or through financial price risk management.



Bitumen Realization

Bitumen realization represents the Corporation's blend sales net of cost of diluent, expressed on a per barrel of bitumen basis. Blend sales represents the Corporation's revenue from its oil blend known as AWB, which is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. The cost of diluent is impacted by Canadian and U.S. benchmark pricing, the amount of diluent required, the cost of transporting diluent to the production site from both Edmonton and U.S. Gulf Coast ("USGC") markets, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar. A portion of the cost of diluent is effectively recovered in the sales price of the blended product. Bitumen realization per barrel fluctuates primarily based on average benchmark prices and light:heavy oil differentials.

	Three months ended March 31			
	2020		2019	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	**$ 469**		$ 696	
Sales from purchased product[1]	**179**		203	
Petroleum revenue	**$ 648**		$ 899	
Purchased product	**(176)**		(196)	
Blend sales[2]	**$ 472**	**$ 36.46**	$ 703	$ 59.02
Cost of diluent	**(300)**	**(17.01)**	(297)	(8.81)
Bitumen realization	**$ 172**	**$ 19.45**	$ 406	$ 50.21

Average Commodity Prices:	$/bbl	$/bbl
WTI (US$/bbl)	**$ 46.17**	$ 54.90
Differential – WTI:AWB – Edmonton (US$/bbl)	**(22.78)**	(14.50)
AWB – Edmonton (US$/bbl)	**$ 23.39**	$ 40.40
AWB – Edmonton (C$/bbl)	**$ 31.45**	$ 53.70
WTI (US$/bbl)	**$ 46.17**	$ 54.90
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(5.74)**	(0.89)
AWB – U.S. Gulf Coast (US$/bbl)	**$ 40.43**	$ 54.01
AWB – U.S. Gulf Coast (C$/bbl)	**$ 54.36**	$ 71.80

(1) Sales from purchased oil products related to marketing asset optimization activities.
(2) Blend sales per barrel are based on blend sales volumes.

The blend sales price decreased by $22.56 per barrel, or 38%, during the three months ended March 31, 2020 compared to the blend sales price during the same period of 2019, due to a lower WTI price and wider WTI:AWB differentials. The WTI price experienced a modest decline through February 2020 followed by a significant decline in early March 2020, largely driven by unprecedented demand shock in the global oil markets due to the COVID-19 global pandemic. The widening of the WTI:AWB differential at Edmonton reflects prevailing demand/supply fundamentals for oil in Western Canada and egress constraints moving beyond Western Canada. However, the Alberta Government Curtailment rules came into force January 1, 2019 which caused the WTI:AWB differential to significantly narrow during the first quarter of 2019.

Cost of diluent increased by $8.20 per barrel, or 93%, during the three months ended March 31, 2020 compared to the same period of 2019 reflecting the use of higher priced diluent from inventory resulting in a lower recovery of the cost of diluent through blend sales. Together with the lower blend sales price, these compounding factors decreased bitumen realization by $30.76 per barrel, or 61%, during the three months ended March 31, 2020 compared to the same period of 2019.

Transportation and Storage

The Corporation's marketing strategy focuses on maximizing the realized AWB sales price after transportation and storage costs by utilizing its network of pipeline, rail and storage facilities to optimize market access.

	Three months ended March 31			
	2020		2019	
($millions, except as indicated)		$/bbl		$/bbl
Transportation and storage	**$ (77)**	**$ (8.63)**	$ (91)	$ (11.27)

During the three months ended March 31, 2020, transportation and storage costs per barrel decreased 23%, compared to the same period of 2019. The decrease is primarily the result of decreased blend sales volumes transported by rail to the USGC market. During the first quarter of 2020, the Corporation suspended its contracted transport of blend sales by rail to the USGC in favour of increasing its blend sales freight on board ("FOB") at rail terminals at Edmonton. The Corporation no longer leases rail cars or has contracted rail commitments beyond loading capacity of FOB sales at Edmonton.

Royalties

The Corporation's royalty expense is calculated based on price-sensitive royalty rates set by the Government of Alberta. The royalty rate applicable to the Corporation's Christina Lake operation, which is currently in pre-payout, starts at 1% of bitumen sales and increases for every dollar that the WTI crude oil price in Canadian dollars is priced above $55 per barrel, to a maximum of 9% when the WTI crude oil price is $120 per barrel or higher. The applicable royalty rate is then applied to revenue for royalty purposes.

	Three months ended March 31			
	2020		2019	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Royalties	**$ (6)**	**$ (0.63)**	$ (3)	$ (0.37)

The increase in royalties for the three months ended March 31, 2020, compared to the same period of 2019, is primarily due to a $4 million recovery that was recognized during the three months ended March 31, 2019 related to prior year royalty rate adjustments.

Net Operating Costs

Net operating costs are comprised of the sum of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-related operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate steam and power at the Corporation’s facilities. Power revenue is recognized from the sale of surplus power generated by the Corporation’s cogeneration facilities at the Christina Lake Project. The Corporation utilizes thermally efficient cogeneration facilities to provide a portion of its steam and electricity requirements. Any excess power that is sold into the provincial power grid displaces other power sources that have a higher carbon intensity, thereby reducing the Corporation's carbon footprint.

	Three months ended March 31			
	2020		2019	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Operating costs - non-energy	**$ (40)**	**$ (4.57)**	$ (42)	$ (5.22)
Operating costs - energy	**(28)**	**(3.15)**	(27)	(3.36)
Power revenue	**20**	**2.21**	20	2.41
Net operating costs	**$ (48)**	**$ (5.51)**	$ (49)	$ (6.17)
Average natural gas purchase price (C$/mcf)		**$ 2.63**		$ 3.03
Average realized power sales price (C$/Mwh)		**$ 69.39**		$ 70.83

Net operating costs per barrel for the three months ended March 31, 2020 decreased 11% compared to the same period of 2019 predominantly due to additional bitumen sales volumes.

Realized Gain or Loss on Commodity Risk Management

The Corporation enters into financial commodity risk management contracts to increase the predictability of the Corporation's cash flow by managing commodity price volatility.

	Three months ended March 31			
	2020		2019	
($millions, except as indicated)		$/bbl		$/bbl
Realized gain (loss) on commodity risk management	**$ 106**	**$ 11.97**	$ (21)	$ (2.60)

To mitigate the Corporation's exposure to fluctuations in commodity prices, the Corporation periodically enters into financial commodity risk management contracts. During the three months ended March 31, 2020, realized gains were recognized significantly increasing the Corporation's cash operating netback from $43 million to $149 million. The extreme volatility in global crude oil prices experienced beginning early March 2020, including the significant weakening of WTI prices relative to crude oil contracted prices, were the largest contributor to realized gains during the period. Realized losses were recognized during the three months ended March 31, 2019. Refer to the commodity risk management discussion within the "OTHER OPERATING RESULTS" section of this MD&A for further details.

Marketing Activity

The following tables summarize the Corporation's blend sales, net of transportation and storage at Edmonton by sales market for the periods noted to assist in understanding the Corporation's marketing portfolio. All per barrel figures presented in this section of the MD&A are based on US$ per barrel of blend sales volumes unless otherwise indicated:

	Three months ended March 31, 2020				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)
WTI	$ 46.17	$ 46.17	$ 46.17	$ 46.17	$ 46.17
Differential - WTI:AWB at sales point	(23.99)	(21.56)	(4.41)	3.49	(19.05)
Blend sales price	22.18	24.61	41.76	49.66	27.12
Transportation and storage[(1)]	(1.82)	(3.45)	(11.01)	(24.73)	(4.39)
Transportation and storage from Christina Lake to Edmonton[(2)]	1.82	1.82	1.82	1.82	1.82
Blend sales price, net of transportation & storage at Edmonton	$ 22.18	$ 22.98	$ 32.57	$ 26.75	$ 24.55
Total blend sales - bbls/d	82,957	27,867	29,271	2,285	142,380
% of total sales	58%	19%	21%	2%	100%

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 22.79	$ 42.33	$ 19.54
Transportation and storage[(1)]	(2.23)	(12.00)	(9.77)
Transportation and storage from Christina Lake to Edmonton[(2)]	1.82	1.82	—
Blend sales price, net of transportation & storage at Edmonton	$ 22.38	$ 32.15	$ 9.77

	Three months ended March 31, 2019				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)
WTI	$ 54.90	$ 54.90	$ 54.90	$ 54.90	$ 54.90
Differential - WTI:AWB at sales point	(15.64)	(10.82)	0.23	(2.97)	(10.50)
Blend sales price	39.26	44.08	55.13	51.93	44.40
Transportation and storage[(1)]	(1.79)	(4.57)	(10.92)	(23.32)	(5.75)
Transportation and storage from Christina Lake to Edmonton[(2)]	1.79	1.79	1.79	1.79	1.79
Blend sales price, net of transportation & storage at Edmonton	$ 39.26	$ 41.30	$ 46.00	$ 30.40	$ 40.44
Total blend sales - bbls/d	80,754	10,099	32,974	8,550	132,377
% of total sales	61%	8%	25%	6%	100%

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 39.80	$ 54.46	$ 14.66
Transportation and storage[(1)]	(2.10)	(13.47)	(11.37)
Transportation and storage from Christina Lake to Edmonton[(2)]	1.79	1.79	—
Blend sales price, net of transportation & storage at Edmonton	$ 39.49	$ 42.78	$ 3.29

(1) *Defined as transportation and storage expenses less transportation revenue, per barrel of blend sales volumes. For reference, total transportation and storage costs per barrel, based on bitumen sales volumes, were C$8.63 per barrel for the three months ended March 31, 2020 compared to C$11.27 per barrel for the three months ended March 31, 2019.*

(2) *Includes all transportation and storage costs associated with moving barrels of blend from Christina Lake to Edmonton sales point.*

(3) *Results are translated at the average foreign exchange rate of 1.3445 for the three months ended March 31, 2020 and 1.3293 for the three months ended March 31, 2019.*

Excluding transportation and storage costs upstream of the Edmonton index sales point, the Corporation's blend sales price averaged US$24.55 per barrel during the three months ended March 31, 2020 compared to the posted AWB benchmark price at Edmonton of US$23.39 per barrel. Notwithstanding that Enbridge Mainline apportionment averaged 50% during first quarter of 2020, the Corporation was able to capture pricing above the Edmonton index as a result of its marketing and storage assets and the ability to move barrels to the higher-priced USGC market.

Blend sales for the three months ended March 31, 2020 averaged 142,380 bbls/d compared to 132,377 bbls/d for the three months ended March 31, 2019. During the first quarter of 2020, the Corporation suspended its contracted transport of blend sales by rail to the USGC in favour of increasing its blend sales FOB at rail terminals at Edmonton. These FOB rail contracts were entered into to take advantage of the Alberta Government's Special Production Allowance ("SPA") program for curtailed producers announced October 2019. The Corporation no longer leases rail cars or has contracted rail commitments beyond loading capacity of FOB sales at Edmonton.

The per barrel premium earned on blend sales is largely due to the Corporation's secured access to the USGC, where sales pricing was not subject to the same light:heavy oil differential as the Edmonton market. Net of transportation and storage costs, blend barrels sold at the USGC realized a US$9.77 per barrel premium to those sold at Edmonton during the three months ended March 31, 2020. This compares to a US$3.29 per barrel premium at the USGC compared to Edmonton during the three months ended March 31, 2019. The premium recognized during the three months ended March 31, 2020 was higher than the same period of 2019 primarily due to the wider WTI:AWB differential at Edmonton during the first quarter of 2020 and lower rail volumes allocated to the USGC market.

In March 2020, and subsequent to March 31, 2020, the dramatic fall in crude oil prices has had a significant impact on transportation out of Alberta, and in particular reduced Enbridge Mainline apportionment. The Corporation continues to evaluate its sales strategy, including the on-going use of FOB rail shipments, to maximize the value of its production.

Revenue

Revenue represents the total of petroleum revenue, including sales of third-party products related to marketing asset optimization activity, net of royalties, and other revenue.

	Three months ended March 31	
($millions, except as indicated)	**2020**	**2019**
Sales from:		
Production	**$ 469**	$ 696
Purchased product[(1)]	**179**	203
Petroleum revenue	**$ 648**	$ 899
Royalties	**(6)**	(3)
Petroleum revenue, net of royalties	**$ 642**	$ 896
Power revenue	**$ 20**	$ 20
Transportation revenue	**3**	3
Other revenue	**$ 23**	$ 23
Total revenues	**$ 665**	$ 919

(1) The associated third-party purchases are included in the consolidated statement of earnings (loss) and comprehensive income (loss) under the caption "Purchased product".

During the three months ended March 31, 2020, revenue decreased 28% from the same period of 2019 primarily as a result of the decrease to the average blend sales price driven by the decline in WTI price and the widening of the WTI:AWB differential, partially offset by the increase in blend sales volumes.

Net Loss

	Three months ended March 31	
($millions, except per share amounts)	**2020**	**2019**
Net loss	**$ (284)**	$ (48)
Per share, diluted	**$ (0.95)**	$ (0.16)

The net loss for the three months ended March 31, 2020 increased from the same period of 2019 as a result of the decreased cash operating netback as well as other non-cash charges. These non-cash charges include an exploration expense of $366 million which was recognized in relation to certain non-core growth properties which will not be pursued further, an unrealized foreign exchange loss of $267 million and an inventory impairment of $29 million partially offset by a $429 million unrealized gain on commodity risk management contracts.

By comparison, the net loss for the period ended March 31, 2019 included an unrealized loss on commodity risk management contracts totaling $209 million partially offset by an unrealized foreign exchange gain of $77 million and a gain on asset disposition of $12 million, related to the sale of earned Emission Performance Credits.

Capital Expenditures

	Three months ended March 31	
($millions)	**2020**	**2019**
Sustaining and maintenance	**$ 40**	$ 22
Phase 2B brownfield expansion	**13**	13
eMVAPEX	**1**	8
Field infrastructure, corporate and other	**—**	10
	$ 54	$ 53

(1) Certain prior year costs have been reclassified for consistency with the Corporation's Phase 2B brownfield development plan.

Capital spending for the three months ended March 31, 2020 and March 31, 2019 are similar and reflect the Corporation's disciplined capital budget for both periods. Capital expenditures during the three months ended March 31, 2020 were primarily directed towards sustaining and maintenance activities as well as advancing work already underway on the Phase 2B brownfield expansion which has since been put on hold given the current economic environment.

4. OUTLOOK

Summary of 2020 Guidance	**Revised Guidance (May 4, 2020)**	**Previously Revised Guidance (March 10, 2020)**	**Original Guidance (November 21, 2019)**
Production (1H20)	76,000 bbls/d	N/A	N/A
Production (FY20 average)	N/A	93,000 - 95,000 bbls/d	94,000 - 97,000 bbls/d
Non-energy operating cost	$140 - $150 million	$155 - $165 million ($4.50 - $4.90 per barrel)	$160 - $170 million ($4.50 - $4.90 per barrel)
G&A expense	$52.5 - $55 million	$60 - $62.5 million ($1.75 - $1.85 per barrel)	$62.5 - $65 million ($1.75 - $1.85 per barrel)
Capital expenditures	$150 million	$200 million	$250 million

Since early March 2020 global crude oil prices have experienced multi-decade lows coupled with extreme levels of volatility driven primarily by the unprecedented demand shock due to COVID-19. Notwithstanding the Corporation's strong financial liquidity, the Corporation is further reducing its 2020 full year capital budget to $150 million from the previously revised level of $200 million, of which $125 million will be directed toward sustaining and maintenance activities, including approximately $25 million related to major plant turnaround activities at the Corporation’s Phase 1 & 2 facilities scheduled to begin in early June 2020. Relative to the original budget, the turnaround is expected to be longer in duration, with completion expected in August, while being undertaken at a lower total cash cost by relying more heavily on internal resources. This will allow the Corporation to take advantage of the current low oil price environment by reducing turnaround requirements in 2021. The remainder of the revised capital budget will be directed primarily towards regulatory, corporate and other.

The Corporation currently expects first half 2020 production to average approximately 76,000 bbls/d. In light of the current oil price environment, the Corporation is suspending full year 2020 production guidance. At present, the Corporation expects to produce approximately 30,000 bbls/d during the Phase 1 & 2 turnaround. This production volume reflects the minimum production level required to maintain the integrity of its operations and reservoir performance at the Phase 2B facility, which has current productive capacity of approximately 60,000 bbls/d. During the turnaround, if oil prices improve from current levels, the Corporation will have the ability to efficiently produce up to this 60,000 bbls/d level. Upon completion of the turnaround activities at the Corporation's Phase 1 & 2 facilities in August, the Corporation will determine, based on the oil price environment at that time, when to bring these facilities back into operation. Irrespective of actual production levels in the second half of 2020, which will be a function of the oil price environment as we move through the year, based on full year $150 million capital investment for 2020, the Corporation will have the ability to achieve production levels in excess of 80,000 bbls/d post turnaround, once Phase 1 & 2 are brought back into operation.

In consideration of the significant impact COVID-19 is having on the Corporation’s bitumen realizations, the Corporation has taken further steps to reduce its 2020 full year non-energy operating costs and G&A expense. Non-energy operating costs are now targeted at $140 - $150 million, which is $20 million, or approximately 12%, lower than original guidance. G&A is now targeted at $52.5 - $55 million, which is $10 million, or approximately 16%, lower than original guidance. The majority of these cost reductions were a result of a reduction in staffing levels and rationalization of ongoing administrative costs. Targeted 2020 G&A expense is approximately $15 million, or 20%, lower than actual 2019 G&A expense, and approximately $30 million, or 35%, lower than 2018 G&A expense.

5. BUSINESS ENVIRONMENT

The following table shows industry commodity pricing information and foreign exchange rates for the periods noted to assist in understanding the impact of commodity prices and foreign exchange rates on the Corporation's financial results:

	2020	2019				2018		
	Q1	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Average Commodity Prices								
Crude oil prices								
Brent (US$/bbl)	**50.95**	62.50	61.97	68.32	63.90	68.08	75.97	74.90
WTI (US$/bbl)	**46.17**	56.96	56.45	59.82	54.90	58.81	69.50	67.88
Differential – WTI:WCS – Edmonton (US$/bbl)	**(20.53)**	(15.83)	(12.24)	(10.67)	(12.29)	(39.43)	(22.25)	(19.27)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(22.78)**	(18.44)	(14.52)	(12.32)	(14.50)	(44.60)	(25.69)	(22.21)
AWB – Edmonton (US$/bbl)	**23.39**	38.52	41.93	47.50	40.40	14.21	43.81	45.67
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(5.74)**	(5.25)	(2.50)	1.64	(0.89)	(6.25)	(5.63)	(7.83)
AWB – U.S. Gulf Coast (US$/bbl)	**40.43**	51.71	53.95	61.46	54.01	52.56	63.87	60.05
Condensate prices								
Condensate at Edmonton (C$/bbl)	**61.76**	70.01	68.73	74.76	67.25	59.63	87.35	88.84
Condensate at Edmonton as % of WTI	**99.5%**	93.1%	92.2%	93.4%	92.1%	76.7%	96.2%	101.4%
Condensate at Mont Belvieu, Texas (US$/bbl)	**39.27**	50.08	44.34	50.22	48.31	51.21	64.53	64.40
Condensate at Mont Belvieu, Texas as % of WTI	**85.1%**	87.9%	78.5%	84.0%	88.0%	87.1%	92.8%	94.9%
Natural gas prices								
AECO (C$/mcf)	**2.26**	2.70	0.95	1.12	2.86	1.70	1.28	1.26
Electric power prices								
Alberta power pool (C$/MWh)	**66.38**	47.07	46.95	56.37	70.73	55.57	54.46	55.92
Foreign exchange rates								
C$ equivalent of 1 US$ – average	**1.3445**	1.3201	1.3207	1.3376	1.3293	1.3215	1.3070	1.2911
C$ equivalent of 1 US$ – period end	**1.4120**	1.2965	1.3244	1.3091	1.3360	1.3646	1.2924	1.3142

Beginning in early March 2020, market events and conditions, including global excess crude oil supply primarily due to an unprecedented reduction in global demand due to the COVID-19 pandemic, have caused significant degradation and volatility in global commodity prices. With the rapid spread of COVID-19, reduced crude oil demand and excess supply, the price of crude oil and other petroleum products has deteriorated significantly and is expected to remain volatile until there is better visibility on the timing of the return to a more stable economic environment.

These events and conditions have also caused a significant decrease in the valuation of oil and natural gas companies. These difficulties have been exacerbated in Canada by actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the difficulties encountered to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in western Canada has led to additional downward price pressure on oil and natural gas produced in western Canada.

Crude Oil Prices

Brent crude is the primary world price benchmark for global light sweet crude oil. The price of WTI is the current benchmark for mid-continent North American crude oil prices, at Cushing Oklahoma, and its Canadian dollar equivalent is the basis for determining the royalty rate on the Corporation's bitumen sales.

WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. WCS typically trades at a differential below the WTI benchmark price. The WCS benchmark at Edmonton reflects North American heavy oil prices at Hardisty, Alberta.

The Corporation sells AWB, an oil similar to WCS, but generally priced at a discount to the WCS benchmark at Edmonton, with the discount dependent on both the quality differential between AWB and WCS and the supply/demand fundamentals for oil in Western Canada. AWB is also sold at the USGC and is sold at a discount or premium to WTI dependent on the supply/demand fundamentals for oil in the USGC region.

On December 3, 2018 the Government of Alberta enacted rules to enable a temporary curtailment of crude oil and bitumen production. The Curtailment Rules came into force on January 1, 2019, and are in place until December 31, 2020, with possible earlier termination. The Curtailment Rules give the Province the authority to make an order to set the maximum combined provincial production amount of crude oil and bitumen on a monthly basis. The limit is monitored closely and adjusted to match export capacity out of the province.

On October 31, 2019 the Government of Alberta SPA program was enacted to give crude oil and bitumen producers temporary curtailment relief equal to incremental increases in rail shipments. On a monthly basis, operators can apply to increase oil production if additional product is moved by new rail capacity out of the province.

Condensate Prices

In order to facilitate pipeline transportation of bitumen, the Corporation uses condensate as diluent for blending with the Corporation's bitumen. The Corporation sources its condensate from the Edmonton area, but due to high demand for condensate in the Edmonton market, the Corporation also purchases condensate from the USGC market where pricing is generally lower. The Corporation's committed diluent purchases at the USGC reference benchmark pricing at Mont Belvieu, Texas. During the first quarter of 2020 the cost of condensate sourced from Mont Belvieu, Texas included net transportation costs of approximately US$6.10 per barrel of condensate to move the product from Mont Belvieu to the Edmonton area.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, used as fuel to generate steam for the thermal production process and to create steam and electricity from the Corporation's cogeneration facilities. The AECO natural gas price decreased during the three months ended March 31, 2020 compared to the same period of 2019 as a result of increased natural gas supply and mild weather reducing Alberta demand in February and March of 2020.

Electric Power Prices

Electric power prices impact the price that the Corporation receives on the sale of surplus power from the Corporation's cogeneration facilities. The Alberta power pool price decreased during the three months ended March 31, 2020 compared to the same period of 2019 primarily as a result of abundant wind generation and mild winter conditions in February and March of 2020.

Foreign Exchange Rates

Changes in the value of the Canadian dollar relative to the U.S. dollar have an impact on the Corporation's blend sales and diluent expense, as blend sales prices and diluent expense are determined by reference to U.S. benchmarks. Changes in the value of the Canadian dollar relative to the U.S. dollar also have an impact on principal and interest payments on the Corporation's U.S. dollar denominated debt.

The Corporation recognizes net unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents at each reporting date. As at March 31, 2020 the Canadian dollar had decreased in value by approximately 9% against the U.S. dollar compared to its value as at December 31, 2019.

6. OTHER OPERATING RESULTS

Depletion and Depreciation

	Three months ended March 31	
($millions)	**2020**	**2019**
Depletion and depreciation expense	**$ 124**	$ 115
Depletion and depreciation expense per barrel of production	**$ 14.83**	$ 14.68

The Corporation incurred an accelerated depreciation expense of $13 million, or $1.57 per barrel, in the first quarter of 2020 given the uncertainty of future benefits associated with certain non-core assets. Excluding the accelerated depreciation expense, depletion and depreciation expense per barrel was $13.26 per barrel for the three months ended March 31, 2020 compared to $14.68 per barrel for the three months ended March 31, 2019. The decrease from the same period of 2019 is primarily due to lower depreciable costs.

Exploration Expense

	Three months ended March 31	
($millions)	**2020**	**2019**
Exploration expense	**$ 366**	—

The Corporation has discontinued exploration and evaluation activities at this time in certain non-core growth properties and as such the associated land lease and evaluation costs totaling $366 million have been charged to exploration expense during the three months ended March 31, 2020. This is a result of focusing on the development of core assets to manage the business through an unpredictable global downturn of unknown duration, coupled with a steady shift away from near term growth at this time.

Risk Management Gain (Loss)

The Corporation enters into financial risk management contracts to increase the predictability of the Corporation's cash flow by managing commodity price volatility, share price volatility and foreign exchange volatility. The Corporation has not designated any of its risk management contracts as hedges for accounting purposes. All financial risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss). Realized gains or losses on financial risk management contracts are the result of contract settlements during the period. Unrealized gains or losses on financial risk management contracts represent the change in the mark-to-market position of the unsettled risk management contracts during the period.

	Three months ended March 31	
($millions)	**2020**	**2019**
Realized:		
Crude oil contracts[1]	**$ 109**	$ (18)
Condensate contracts[2]	**(3)**	(3)
Realized risk management gain (loss)	**$ 106**	$ (21)
Unrealized:		
Crude oil contracts[1]	**$ 439**	$ (202)
Condensate contracts[2]	**(11)**	(7)
Share price contracts[3]	**1**	—
Unrealized risk management gain (loss)	**$ 429**	$ (209)
Risk management gain (loss)	**$ 535**	$ (230)

(1) Includes WTI fixed price contracts, WTI options and WTI:WCS fixed differential contracts.
(2) Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas relative to WTI.
(3) Relates to financial derivatives entered into to manage the Corporation's exposure to cash-settled RSUs and PSUs vesting in 2021, 2022 and 2023 granted under the Corporation's stock-based compensation plans.

For the three months ended March 31, 2020, the Corporation recognized a $535 million net gain from risk management primarily due to weakening WTI prices relative to contracted prices. This compares with the $230 million net loss from risk management for the three months ended March 31, 2019, when WTI forward prices strengthened and WTI:WCS forward differentials narrowed relative to contracted prices.

The realized risk management gain (loss) represents actual contract settlements over the periods presented. The following table provides further details regarding the realized risk management gains (losses):

	Three months ended March 31	
($/bbl)	**2020**	**2019**
WTI fixed price contracts:		
Average fixed price	**$ 58.67**	$ 64.39
Average settlement price	**46.17**	54.90
Gain (loss) on WTI fixed price contracts	**$ 12.50**	$ 9.49
WTI:WCS fixed differential contracts:		
Average fixed differential	**$ (22.18)**	$ (23.34)
Average settlement differential	**(20.53)**	(12.29)
Gain (loss) on WTI:WCS fixed differential contracts	**$ (1.65)**	$ (11.05)
Condensate purchase contracts:		
Average fixed differential[1]	**$ (5.33)**	$ (4.28)
Average settlement differential	**(6.90)**	(6.59)
Gain (loss) on condensate purchase contracts	**$ (1.57)**	$ (2.31)

(1) Condensate purchase contracts either fix the WTI:condensate differential at Mont Belvieu, Texas relative to WTI or fix the condensate price as a % of WTI.

General and Administrative

	Three months ended March 31	
($millions)	**2020**	**2019**
General and administrative expense	**$ 16**	$ 18
General and administrative expense per barrel of production	**$ 1.96**	$ 2.27

General and administrative expense decreased 11% for the three months ended March 31, 2020 compared to the same period of 2019, primarily due to rationalization of ongoing administrative costs.

Stock-based Compensation

	Three months ended March 31	
($millions)	**2020**	**2019**
Cash-settled recovery	**$ (18)**	$ (9)
Equity-settled expense	**5**	4
Stock-based compensation recovery	**$ (13)**	$ (5)

Primarily as a result of the unprecedented economic impact of the COVID-19 global pandemic, as at March 31, 2020, the Corporation's common share price decreased to $1.67 per share, a 77% decrease from its value of $7.39 per share on December 31, 2019 which resulted in an $18 million cash-settled stock-based compensation recovery. As at March 31, 2019 , the Corporation's common share price decreased by approximately 34% compared to its value on December 31, 2018 primarily related to Husky Energy's unsuccessful unsolicited bid to acquire all of the outstanding shares of the Corporation on January 17, 2019.

Foreign Exchange Gain (Loss), Net

	Three months ended March 31	
($millions)	**2020**	**2019**
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ (278)**	$ 79
US$ denominated cash and cash equivalents	**11**	(2)
Unrealized net gain (loss) on foreign exchange	**(267)**	77
Realized gain (loss) on foreign exchange	**(3)**	1
Foreign exchange gain (loss), net	**$ (270)**	$ 78

C$ equivalent of 1 US$		
Beginning of period	**1.2965**	1.3646
End of period	**1.4120**	1.3360

During the three months ended March 31, 2020, the Canadian dollar weakened relative to the U.S. dollar by 9%, resulting in an unrealized foreign exchange loss of $267 million. During the three months ended March 31, 2019, the Canadian dollar strengthened by 2%, resulting in an unrealized foreign exchange gain of $77 million.

Net Finance Expense

	Three months ended March 31	
($millions)	**2020**	**2019**
Interest expense on long-term debt	**$ 64**	$ 72
Interest expense on lease liabilities	**6**	7
Interest income	**(2)**	(2)
Net interest expense	**68**	77
Accretion on provisions	**2**	1
Net finance expense	**$ 70**	$ 78
Average effective interest rate	**6.8%**	6.6%

As a result of the senior secured term loan repayment in July 2019 and partial redemptions on its senior secured second lien notes and senior unsecured notes during the second half of 2019 and the first quarter of 2020, net finance expense for the three months ended March 31, 2020 decreased, compared to the same period of 2019.

Income Tax

	Three months ended March 31	
($millions)	**2020**	**2019**
Income tax expense (recovery)	**$ (2)**	$ (45)
Effective tax rate	**1%**	48%

As at March 31, 2020, the Corporation had approximately $7.3 billion of available Canadian tax pools and recognized a deferred income tax asset of $264 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

The effective tax rate of 1% for the three months ended March 31, 2020 is lower than the Canadian statutory rate of 25% due to the tax effect of realized and unrealized foreign exchange losses on the Corporation's debt.

7. LIQUIDITY AND CAPITAL RESOURCES

($millions)	March 31, 2020	December 31, 2020
Second Lien:		
6.5% senior secured second lien notes (March 31, 2020 - US$496 million; December 31, 2019 - US$596 million; due 2025)	**$ 701**	$ 773
Unsecured:		
7.0% senior unsecured notes (March 31, 2020 - US$600 million; December 31, 2019 - US$1 billion; due 2024)	**847**	1,297
7.125% senior unsecured notes (March 31, 2020 - US$1.2 billion; December 31, 2019 - US$nil; due 2027)	**1,694**	—
6.375% senior unsecured notes (March 31, 2020 - US$nil; December 31, 2019 - US$800 million; due 2023)	**—**	1,037
Less:		
Debt redemption premium	**—**	29
Unamortized deferred debt discount and debt issue costs	**(30)**	(13)
Long-term debt	**3,212**	3,123
Cash and cash equivalents	**(62)**	(206)
Net debt[(1)]	**$ 3,150**	$ 2,917

(1) *Net debt is reconciled to long-term debt in accordance with IFRS in Note 19 of the interim consolidated financial statements.*

During the three months ended March 31, 2020 net debt increased by $233 million primarily due to the weakening of the Canadian dollar relative to the US dollar partially offset by the partial redemption of its 6.5% senior secured second lien notes.

On January 31, 2020 the Corporation successfully closed a private offering of $1.6 billion (US$1.2 billion) in aggregate principal amount of 7.125% senior unsecured notes due February 2027. On February 18, 2020, the net proceeds of the offering, together with cash on hand, were used to:

- Fully redeem $1 billion (US$800 million) of the 6.375% senior unsecured notes due January 2023 at a redemption price of 101.063%;
- Partially redeem $530 million (US$400 million) of the US$1.0 billion 7.00% senior unsecured notes due March 2024 at a redemption price of 102.333%; and
- Pay fees and expenses related to the offering.

Concurrent with the private offering, on February 18, 2020, the Corporation redeemed $132 million (US$100 million) in aggregate principal amount of its 6.5% senior secured second lien notes due January 2025 at a redemption price of 104.875%. Cash on hand was used to fund this senior secured second lien notes partial redemption.

The Corporation's cash and cash equivalents balance was $62 million as at March 31, 2020 compared to $206 million as at December 31, 2019. Adjusted funds flow of $78 million during the three months ended March 31, 2020 was more than offset by the repayment of debt and capital expenditures. Refer to the "Cash Flow Summary" section for further details.

The Corporation has total available credit under two facilities of $1.3 billion, comprised of $800 million under the revolving credit facility and $500 million under the EDC Facility. Letters of credit under the EDC facility do not consume capacity of the revolving credit facility. The revolving credit facility and the EDC Facility have a maturity date of July 30, 2024. The maturity dates of the revolving credit facility and the EDC Facility include a feature that would cause the maturity dates to spring back to 91 days prior to the maturity date of certain material debt of the Corporation if such debt has not been repaid or refinanced prior to such date.

The revolving credit facility does not contain a financial maintenance covenant unless the Corporation is drawn under the revolving credit facility in excess of $400 million. If the facility is drawn in excess of $400 million, the Corporation is required to maintain a first lien net debt to last twelve months earnings before interest, tax, depreciation and amortization ratio of 3.50 or less. The financial maintenance covenant, if triggered, will be tested quarterly. Issued letters of credit are not included in the calculation of the ratio.

The revolving credit facility, EDC facility and senior secured second lien notes are secured by substantially all the assets of the Corporation.

As at March 31, 2020, the Corporation had $787 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $63 million of unutilized capacity under the $500 million letter of credit facility. A letter of credit of $13 million was issued under the revolving credit facility in the first quarter of 2020.

In response to the current business environment, the Corporation implemented additional measures to enhance its financial liquidity position including the reduction of planned capital spending by $100 million, non-energy operating costs by $20 million and G&A costs by $10 million, versus original guidance. Meeting current and future obligations through the uncertainty associated with the COVID–19 global pandemic is supported by the Corporation's financial framework including a strong commodity risk management program securing cash flow through 2020 and credit risk management policies minimizing exposure related to customer receivables primarily to investment grade customers in the energy industry. The Corporation's earliest maturing long-term debt is four years out, represented by US$600 million of senior unsecured notes due March 2024. None of the Corporation's outstanding long-term debt contain financial maintenance covenants. Additionally, the Corporation's modified covenant-lite $800 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $400 million. If drawn in excess of $400 million, the Corporation is required to maintain a quarterly first lien net leverage ratio (first lien net debt to last twelve-month EBITDA) of 3.5 or less. Under the Corporation's credit facility, first lien net debt is calculated as debt under the credit facility plus other debt that is secured on a *pari passu* basis with the credit facility, less cash on hand.

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary. The Corporation's cash flow and the development of projects are dependent on factors discussed in the "RISK FACTORS" section of this MD&A.

Cash Flow Summary

	Three months ended March 31	
($millions)	**2020**	**2019**
Net cash provided by (used in):		
Operating activities	**$ 99**	$ (69)
Investing activities	**(59)**	(84)
Financing activities	**(196)**	(8)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**12**	(3)
Change in cash and cash equivalents	**$ (144)**	$ (164)

Cash Flow – Operating Activities

The increase in net cash provided by operating activities for the three months ended March 31, 2020 compared to the three months ended March 31, 2019 is primarily due to a $220 million increase in working capital requirements during the first quarter of 2019 relating mainly to the settlement of December 2018 revenues when benchmark crude oil prices were significantly lower. Before non-cash working capital, funds flow from operating activities decreased for the three months ended March 31, 2020 compared to the three months ended March 31, 2019 due to lower benchmark crude oil prices.

Cash Flow – Investing Activities

Net cash used in investing activities decreased during the three months ended March 31, 2020 compared to the same period of 2019 which reflects the Corporation's reduction in the change in non-cash working capital for the three months ended March 31, 2020.

Cash Flow – Financing Activities

Net cash used in financing activities increased during the three months ended March 31, 2020 compared to the same period of 2019 primarily due to the redemption of a portion of the 6.5% senior secured second lien notes totaling $132 million (US$100 million). Also, a debt redemption premium and other refinanacing costs were incurred related to the January 31, 2020 refinancing.

8. RISK MANAGEMENT

Commodity Price Risk Management

To mitigate the Corporation's exposure to fluctuations in commodity prices, the Corporation periodically enters into financial commodity risk management contracts to partially manage its exposure on blend sales and condensate purchases. The Corporation also periodically enters into physical delivery contracts which are not considered financial instruments and therefore no asset or liability has been recognized in the Consolidated Balance Sheet related to these contracts. The impact of realized physical delivery contract prices is included in the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss) and in cash operating netback.

The Corporation had the following financial commodity risk management contracts relating to crude oil sales and condensate purchases outstanding as at March 31, 2020:

As at March 31, 2020	Volumes (bbls/d)[(1)]	Term	Average Price (US$/bbl)[(1)]
Crude Oil Sales Contracts			
WTI Fixed Price	66,103	Apr 1, 2020 - Jun 30, 2020	$57.75
WTI Fixed Price	17,965	Jul 1, 2020 - Dec 31, 2020	$59.37
WTI:WCS Fixed Differential	33,681	Apr 1, 2020 - Jun 30, 2020	$(18.67)
WTI:WCS Fixed Differential	24,500	Jul 1, 2020 - Dec 31, 2020	$(20.46)
Enhanced Fixed Price with Sold Put Option			
WTI Fixed Price/Sold Put Option Strike Price	20,685	Jul 1, 2020 - Dec 31, 2020	$59.22 / $52.00
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	7,250	Apr 1, 2020 - Dec 31, 2020	$(7.63)
WTI:Mont Belvieu Fixed Differential	10,950	Jan 1, 2021 - Dec 31, 2021	$(10.37)
WTI:Mont Belvieu Fixed Differential	200	Jan 1, 2022 - Dec 31, 2022	$(11.30)
WTI:Mont Belvieu Fixed % of WTI	7,750	Apr 1, 2020 - Dec 31, 2020	93.1 %

(1) *The volumes, prices and percentages in the above table represent averages for various contracts with differing terms and prices. The* average *price and percentages for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.*

The following table summarizes the sensitivity of cash operating netback, adjusted funds flow and earnings (loss) before income tax of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place as at March 31, 2020:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	**$ (70)**	**$ 68**
Crude oil differential price[1]	± US$5.00 per bbl applied to WTI:WCS differential contracts	**$ 53**	**$ (53)**

(1) As the WCS differential is expressed as a discount to WTI, an increase in the differential results in a lower WCS price and a decrease in the differential results in a higher WCS price.

The Corporation had the following physical commodity risk management contracts relating to crude oil sales, condensate purchases and natural gas purchases outstanding as at March 31, 2020:

As at March 31, 2020	Volumes[1]	Term	Average Price[1]
Crude Oil Sales Contracts	**(bbls/d)**		**(US$/bbl)**
WTI:AWB Fixed Differential	13,150	Apr 1, 2020 - Dec 31, 2020	(20.75)
Condensate Purchase Contracts	**(bbls/d)**		**(US$/bbl)**
WTI:Condensate Fixed Differential	8,200	Apr 1, 2020 - Dec 31, 2020	(5.00)
Natural Gas Purchases Contracts	**(Mcf/d)**		**(C$/Mcf)**
Fixed Price Natural Gas Purchases	86,200	Apr 1, 2020 - Apr 30, 2020	1.90

(1) The volumes and prices in the above table represent averages for various contracts with differing terms and prices. The average *price for the portfolio may not have the same payment profile as the individual contracts and is provided for indicative purposes.*

The Corporation entered into the following financial commodity risk management contracts relating to crude oil sales and condensate purchases between March 31, 2020 and May 4, 2020:

Subsequent to March 31, 2020	Volumes (bbls/d)[1]	Term	Average Prices (US$/bbl)[1]
Crude Oil Sales (Purchase) Contracts			
WTI Fixed Price	(6,833)	Apr 1, 2020 - Apr 30, 2020	$22.00
WTI Fixed Price	6,613	May 1, 2020 - May 31, 2020	$25.45
WTI Fixed Price	10,000	Jul 1, 2020 - Sept 30, 2020	$32.37

(1) The volumes and prices in the above table represent averages for various contracts with differing terms and prices. The average *price and percentages for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.*

9. SHARES OUTSTANDING

As at March 31, 2020, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	Units
Common shares	**299.5**
Convertible securities	
Stock options[1]	**6.4**
Equity-settled RSUs and PSUs	**6.5**

(1) 5.0 million stock options were exercisable as at March 31, 2020.

As at May 1, 2020, the Corporation had 302.6 million common shares, 6.4 million stock options and 7.8 million equity-settled restricted share units and equity-settled performance share units outstanding, and 5.6 million stock options exercisable.

10. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations as at March 31, 2020. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities, the senior secured second lien notes, and the senior unsecured notes may be retired earlier due to mandatory or discretionary repayments or redemptions.

($millions)	2020	2021	2022	2023	2024	Thereafter	Total
Commitments:							
Transportation and storage(1)	$ 303	$ 443	$ 433	$ 475	$ 458	$ 6,069	$ 8,181
Diluent purchases	109	23	23	19	—	—	174
Other operating commitments	11	13	12	12	10	42	100
Variable office lease costs	4	5	5	5	5	34	58
Capital commitments	3	—	—	—	—	—	3
Total Commitments	430	484	473	511	473	6,145	8,516
Other Obligations:							
Lease obligations	36	40	38	33	32	520	699
Long-term debt(2)	—	—	—	—	847	2,395	3,242
Interest on long-term debt(2)	169	226	226	226	181	259	1,287
Decommissioning obligation(3)	3	5	5	5	5	793	816
Total Commitments and Obligations	**$ 638**	**$ 755**	**$ 742**	**$ 775**	**$ 1,538**	**$ 10,112**	**$ 14,560**

(1) This represents transportation and storage commitments from 2020 to 2048, including pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet.

(2) This represents the scheduled principal repayments of the senior secured second lien notes, the senior unsecured notes, and associated interest payments based on interest and foreign exchange rates in effect on March 31, 2020.

(3) This represents the undiscounted future obligations associated with the decommissioning of the Corporation's assets.

Contingencies

The Corporation is involved in various legal claims associated with the normal course of operations. The Corporation believes that any liabilities that may arise pertaining to such matters would not have a material impact on its financial position.

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility in Alberta. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation filed a statement of defense in the first quarter of 2018. The Corporation continues to view this claim as without merit and will continue to defend against this claim. The Corporation believes that any liabilities that might arise from this matter are unlikely to have a material effect on its financial position.

11. NON-GAAP MEASURES

Cash operating netback is a non-GAAP measure. Its terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Cash operating netback is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to fund future capital expenditures. The Corporation's cash operating netback is calculated by deducting the related cost of diluent, blend purchases, transportation and storage, third-party curtailment credits, operating expenses, royalties and realized commodity risk management gains or losses from blend sales and power revenue. The per barrel calculation of cash operating netback is based on bitumen sales volume.

12. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting policies and estimates are those estimates having a significant impact on the Corporation's financial position and operations and that require management to make judgments, assumptions and estimates in the application of IFRS. Judgments, assumptions and estimates are based on historical experience and other factors that management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgments, assumptions and estimates may be subject to change. Detailed disclosure of the significant accounting policies and the significant accounting estimates, assumptions and judgments used by the Corporation can be found in the Corporation's annual consolidated financial statements for the year ended December 31, 2019.

There are no comparable recent events that provide guidance as to the effect the COVID-19 global pandemic may have, and as a result, the ultimate impact of the outbreak is highly uncertain and subject to change. The full extent of the impact of COVID-19 on the Corporation's operations and future financial performance is currently unknown. The continued impact on capital and financial markets on a macro-scale presents uncertainty and risk with respect to the Corporation's performance, and the estimates and assumptions used by Management in the preparation of its financial results.

Additional estimates, assumptions and judgments in response to the COVID-19 global pandemic have been disclosed in the interim consolidated financial statements as at March 31, 2020 regarding valuation assessments related to the Corporation's inventories, property, plant and equipment, exploration and evaluation assets, long-term pipeline linefill, decommissioning provision and deferred income tax asset.

13. RISK FACTORS

The Corporation's primary focus is on the ongoing development and operation of its thermal oil assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including among others, operational risks, risks related to economic conditions, environmental and regulatory risks, and financing risks. Many of these risks impact the oil and gas industry as a whole. Further information regarding the risk factors which may affect the Corporation is contained in the most recently filed AIF, which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

Risk related to COVID-19 Global Pandemic

The Corporation's operations, operating results and financial condition could be materially adversely impacted by events related to the COVID-19 global pandemic and actions taken by government authorities in response to the pandemic. The pandemic has resulted in, and may continue to result in, among other things: increased volatility in financial markets and foreign currency exchange rates; disruptions to global supply chains; labour shortages; reductions in trade volumes; temporary operational restrictions and restrictions on gatherings greater than a certain number of individuals, shelter in place declarations and quarantine orders, business closures and travel bans; an overall slowdown in the global economy; political and economic instability; and civil unrest. In particular, the COVID-19 pandemic, and actions taken by governmental authorities in response thereto, have resulted in, and may continue to result in, a reduction in the demand for oil and reduced oil prices. Also, there is an increased risk that oil storage could reach capacity in Canada and the USGC as a result of the decreased demand. A prolonged period of decreased demand for, and lower prices of crude oil, and any applicable storage constraints, could also result in the Corporation voluntarily curtailing or shutting-in production, which could adversely impact our business, financial condition and results of operations.

If crude oil prices continue to remain at low levels for an extended period of time, or if the costs to develop the Corporation's resources significantly increases, the carrying value of its assets may be subject to impairment and net earnings could be adversely affected.

The Corporation is subject to risks relating to a temporary suspension or physical interruption of its operations impacted by a COVID-19 outbreak, particularly at the Corporation's sole operating facility at Christina Lake. In the event an employee or contractor at the Corporation's Christina Lake site becomes infected with COVID-19, it could place the Corporation's entire site workforce at risk, which could result in the suspension of operations. Such a suspension in operations could also be mandated by governmental authorities in response to the COVID-19 pandemic. This would have a significant negative impact on, or shut-down of, the Corporation's production levels, potentially for a sustained period of time, which could adversely impact our business, financial condition and results of operations.

In addition, the disruption and volatility in global capital markets that has resulted, and may continue to result, from the COVID-19 pandemic could increase our cost of capital and adversely affect our ability to access the capital markets on a timely basis, or at all.

The COVID-19 pandemic continues to rapidly evolve and the extent to which it may impact our business, financial condition and results of operations, as well as our future capital expenditures and other discretionary items, will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence, including: the geographic spread of the virus; the duration and extent of the pandemic, further actions that may be taken by governmental authorities, including in respect of travel restrictions and business disruptions; the severity of the disease; its impact on healthcare systems to manage increases in patients; and the effectiveness of actions taken to contain the virus and treat the disease. To the extent that the COVID-19 pandemic adversely affects our business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described in the 2019 annual MD&A and the latest AIF.

Equity Price Risk Management

Equity price risk is the risk that changes in the Corporation's own share price impact earnings and cash flows. Earnings and funds flow from operating activities are impacted when outstanding cash-settled RSUs and PSUs, issued under the Corporation's stock-based compensation plans, are revalued each period based on the Corporation's share price. Net cash provided by (used in) operating activities is impacted when these stock-based compensation units are ultimately settled. The Corporation enters into financial derivative contracts ("share price contracts") to manage these risks.

14. DISCLOSURE CONTROLS AND PROCEDURES

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

15. INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The CEO and CFO are required to cause the Corporation to disclose any change in the Corporation's internal controls over financial reporting that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting. No changes in internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

It should be noted that a control system, including the Corporation's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud. In reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost/benefit relationship of possible controls and procedures.

In mid-March 2020, in accordance with the guidance of provincial and federal health officials and to limit the risk and transmission of COVID-19, the Corporation implemented mandatory self-quarantine policies, travel restrictions, enhanced cleaning and sanitation measures, and social distancing measures, including directing the vast majority of its office staff and certain non-essential field staff to work from home. These changes to processes have not resulted in any material changes to the internal controls over financial reporting.

16. ABBREVIATIONS

The following provides a summary of common abbreviations used in this document:

Financial and Business Environment

AECO	Alberta natural gas price reference location
AIF	Annual Information Form
AWB	Access Western Blend
$ or C$	Canadian dollars
DSU	Deferred share units
EDC	Export Development Canada
eMSAGP	enhanced Modified Steam And Gas Push
eMVAPEX	enhanced Modified VAPour EXtraction
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
MD&A	Management's Discussion and Analysis
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam-oil ratio
U.S.	United States
US$	United States dollars
WCS	Western Canadian Select
WTI	West Texas Intermediate

Measurement

bbl	barrel
bbls/d	barrels per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
MW	megawatts
MW/h	megawatts per hour

17. ADVISORY

Forward-Looking Information

This document may contain forward-looking information within the meaning of applicable securities laws. This forward-looking information is identified by words such as "anticipate", "believe", "could", "curve", "drive", "expect", "estimate", "focus", "forward", "future", "guidance", "may", "on track", "outlook", "plan", "position", "potential", "priority", "should", "strategy", "target", "will", "would" or similar expressions and includes statements about future outcomes, including but not limited to: expectations of future production, revenues, expenses, cash flow, operating costs, steam-oil ratios, pricing differentials, reliability, profitability and capital expenditures; estimates of reserves and resources; anticipated reductions in operating costs as a result of optimization and scalability of certain operations; anticipated sources of funding for operations and capital expenditures; and anticipated regulatory approvals. Such forward-looking information is based on management's expectations and assumptions regarding future growth, results of operations, production, future capital and other expenditures, competitive advantage, plans for and results of drilling activity, environmental matters, and business prospects and opportunities.

Forward-looking information contained in this document is based on management's expectations and assumptions regarding, among other things: future crude oil, bitumen blend, natural gas, electricity, condensate and other diluent prices, foreign exchange rates and interest rates; the recoverability of MEG's reserves and contingent resources; MEG's ability to produce and market production of bitumen blend successfully to customers; extent and timelines of the Alberta Government's mandatory production curtailment program, future growth, results of operations and production levels; future capital and other expenditures; revenues, expenses and cash flow; operating costs; reliability; continued liquidity and runway to sustain operations through a prolonged market downturn; ability to reduce oil sands production, including without negative impacts to its assets; anticipated reductions in operating costs as a result of optimization and scalability of certain operations; anticipated sources of funding for operations and capital investments; plans for and results of drilling activity; plans for and results of turnaround activity; the regulatory framework governing royalties, land use, taxes and environmental matters, including the timing and level of government production curtailment and federal and provincial climate change policies, in which MEG conducts and will conduct its business; the impact of MEG's response to the COVID-19 global pandemic; and business prospects and opportunities. By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated.

By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks and uncertainties include, but are not limited to risks and uncertainties related to: the oil and gas industry, for example, securing access to markets and transportation infrastructure (including pipelines and rail) and the commitments therein; the availability of capacity on the electricity transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and revenues; health, safety and environmental risks; legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws and production curtailment; assumptions regarding and the volatility of commodity prices, interest rates and foreign exchange rates; commodity price, interest rate and foreign exchange rate swap contracts and/or derivative financial instruments that the Corporation may enter into from time to time to manage its risk related to such prices and rates; timing of completion, commissioning, and start-up, of the Corporation's turnarounds; the operational risks and delays in the development, exploration, production, and the capacities and performance associated with the Corporation's projects; the Corporation's ability to reduce or increase production to desired levels; the Corporation's ability to finance sustaining capital expenditures; the Corporation's ability to maintain sufficient liquidity to sustain operations through a prolonged market downturn; changes in credit ratings applicable to the Corporation or any of its securities; the Corporation's response to the COVID-19 global pandemic; the severity and duration of the COVID-19 pandemic; the potential for a temporary suspension of operations impacted by an outbreak of COVID-19; continued weakness and volatility of crude oil and other petroleum products due to decreased global demand due to the COVID-19 pandemic; changes in general economic, market and business conditions; the potential costs associated with ongoing litigation cases; the extent and timelines of the Alberta Government's mandatory production curtailment program; risks of legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws and Federal and Provincial climate change policies; the cost of compliance with current and future environmental laws, including climate change laws; risks related to increased activism and public opposition to fossil fuels and oil sands; assumptions regarding and the volatility of commodity prices, interest rates and foreign exchange rates, and, risks and uncertainties related to commodity price, interest rate and foreign exchange rate swap contracts and/or derivative financial instruments that the Corporation may enter into from time to time to manage its risk related to such prices and rates; and uncertainties arising in connection with any future acquisitions and/or dispositions of assets.

Although the Corporation believes that the assumptions used in such forward-looking information are reasonable, there can be no assurance that such assumptions will be correct. Accordingly, readers are cautioned that the actual results achieved may vary from the forward-looking information provided herein and that the variations may be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive.

Further information regarding the assumptions and risks inherent in the making of forward-looking statements can be found in the Corporation's most recently filed AIF, along with the Corporation's other public disclosure documents. Copies of the AIF and the Corporation's other public disclosure documents are available through the SEDAR website at www.sedar.com.

The forward-looking information included in this document is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this document is made as of the date of this document and the Corporation assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

MEG Energy Corp. is an oil company focused on sustainable in situ thermal oil development and production in the southern Athabasca region of Alberta, Canada. The Corporation is actively developing enhanced oil recovery projects that utilize SAGD extraction methods to improve the economic recovery of oil as well as lower carbon emissions. MEG transports and sells AWB or blend to refiners throughout North America and internationally. The Corporation's common shares are listed on the Toronto Stock Exchange under the symbol "MEG".

Estimates of Reserves and Resources

For information regarding the Corporation's estimated reserves and resources, please refer to the Corporation's AIF.

Non-GAAP Financial Measures

Certain financial measures in this MD&A do not have a standardized meaning as prescribed by IFRS. Cash operating netback is a non-GAAP financial measure. Its terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. This measure is presented and described in order to provide shareholders and potential investors with additional measures in understanding the Corporation's ability to generate funds and to finance its operations as well as profitability measures specific to the oil industry. The definition and reconciliation of this non-GAAP measure is presented in the “NON-GAAP MEASURES” section of this MD&A.

18. ADDITIONAL INFORMATION

Additional information relating to the Corporation, including its AIF, is available on the Corporation's website at www.megenergy.com and is also available on SEDAR at www.sedar.com.

19. QUARTERLY SUMMARIES

	2020	2019				2018(1)		
Unaudited	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**(284)**	26	24	(64)	(48)	(199)	118	(179)
Per share, diluted	**(0.95)**	0.09	0.08	(0.21)	(0.16)	(0.67)	0.39	(0.61)
Adjusted funds flow	**78**	157	192	227	151	(37)	116	18
Per share, diluted	**0.26**	0.51	0.63	0.76	0.50	(0.13)	0.39	0.06
Capital expenditures	**54**	72	40	33	53	144	139	191
Cash and cash equivalents	**62**	206	154	399	154	318	373	564
Working capital	**371**	123	204	416	175	290	274	211
Long-term debt	**3,212**	3,123	3,257	3,582	3,660	3,740	3,544	3,607
Shareholders' equity	**3,593**	3,853	3,828	3,795	3,851	3,886	4,068	3,946
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**46.17**	56.96	56.45	59.82	54.90	58.81	69.50	67.88
Differential – WTI:WCS – Edmonton (US$/bbl)	**(20.53)**	(15.83)	(12.24)	(10.67)	(12.29)	(39.43)	(22.25)	(19.27)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(22.78)**	(18.44)	(14.52)	(12.32)	(14.50)	(44.60)	(25.69)	(22.21)
AWB – Edmonton (US$/bbl)	**23.39**	38.52	41.93	47.50	40.40	14.21	43.81	45.67
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(5.74)**	(5.25)	(2.50)	1.64	(0.89)	(6.25)	(5.63)	(7.83)
AWB – U.S. Gulf Coast (US$/bbl)	**40.43**	51.71	53.95	61.46	54.01	52.56	63.87	60.05
C$ equivalent of 1US$ – average	**1.3445**	1.3201	1.3207	1.3376	1.3293	1.3215	1.3070	1.2911
Natural gas – AECO ($/mcf)	**2.26**	2.70	0.95	1.12	2.86	1.70	1.28	1.26
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**142,380**	134,932	132,455	137,120	132,377	126,750	130,823	108,237
Diluent usage – bbls/d	**(45,166)**	(40,585)	(37,463)	(42,000)	(42,555)	(38,467)	(36,967)	(33,819)
Bitumen sales – bbls/d	**97,214**	94,347	94,992	95,120	89,822	88,283	93,856	74,418
Bitumen production – bbls/d	**91,557**	94,566	93,278	97,288	87,113	87,582	98,751	71,325
Steam-oil ratio (SOR)	**2.31**	2.27	2.26	2.16	2.20	2.22	2.17	2.22
Blend sales	**36.46**	56.55	60.26	69.19	59.02	37.76	63.68	62.41
Cost of diluent	**(17.01)**	(9.69)	(6.89)	(6.96)	(8.81)	(22.45)	(14.05)	(15.08)
Bitumen realization	**19.45**	46.86	53.37	62.23	50.21	15.31	49.63	47.33
Transportation and storage – net	**(8.63)**	(10.75)	(10.57)	(10.80)	(11.27)	(10.28)	(9.11)	(8.28)
Third-party curtailment credits	**0.18**	(0.21)	(0.37)	(0.89)	—	—	—	—
Royalties	**(0.63)**	(1.18)	(1.54)	(2.06)	(0.37)	(0.15)	(2.01)	(1.64)
Operating costs – non-energy	**(4.57)**	(4.49)	(4.22)	(4.53)	(5.22)	(4.25)	(4.38)	(5.47)
Operating costs – energy	**(3.15)**	(2.95)	(1.51)	(1.78)	(3.36)	(1.98)	(1.50)	(1.79)
Power revenue	**2.21**	1.57	1.43	1.65	2.41	1.68	1.54	1.62
Realized gain (loss) on commodity risk management	**11.97**	(0.52)	(4.15)	(5.94)	(2.60)	6.81	(10.16)	(13.11)
Cash operating netback	**16.83**	28.33	32.44	37.88	29.80	7.14	24.01	18.66
Power sales price (C$/MWh)	**69.39**	49.61	50.30	55.33	70.83	55.38	51.53	51.02
Power sales (MW/h)	**129**	124	112	118	128	111	117	98
Average cost of diluent ($/bbl of diluent)	**73.09**	79.07	77.71	84.95	77.61	89.28	99.37	95.60
Average cost of diluent as a % of WTI	**118%**	105%	104%	106%	106%	115%	109%	109%
Depletion and depreciation rate per bbl of production	**14.83**	13.18	13.43	41.22	14.68	13.79	13.85	16.08
General and administrative expense per bbl of production	**1.96**	2.25	1.66	1.81	2.27	2.54	2.35	2.95
COMMON SHARES								
Shares outstanding, end of period (000)	**299,547**	299,508	299,288	299,207	296,857	296,841	296,813	296,751
Common share price ($) - close (end of period)	**1.67**	7.39	5.80	5.02	5.10	7.71	8.03	10.96

(1) *The Corporation adopted IFRS 16 Leases, effective January 1, 2019, therefore prior periods have not been restated.*

During the eight most recent quarters the following items have had a significant impact on the Corporation’s quarterly results:

- fluctuations in blend sales pricing due to significant changes in the price of WTI, which has ranged from US $46.17/bbl to US$69.50/bbl, and the differential between WTI and the Corporation's AWB at Edmonton, which has ranged from US$12.32/bbl to US$44.60/bbl;
- in early March 2020 global crude oil prices started experiencing multi-decade lows coupled with extreme levels of volatility driven primarily by an unprecedented reduction in global demand due to the COVID-19 global pandemic;
- the cost of diluent due to changes in Canadian and U.S. benchmark pricing and the timing of diluent inventory purchases;
- changes in the value of the Canadian dollar relative to the U.S. dollar and its impact on blend sales prices, the cost of diluent, interest expense, and foreign exchange gains and losses associated with the Corporation's U.S. dollar denominated debt;
- increased bitumen production volumes due to efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project, which has allowed additional wells to be placed into production;
- timing of capital projects;
- cost reduction efforts;
- apportionment and the ability to reach USGC markets;
- fluctuations in natural gas and power pricing;
- gains and losses on commodity risk management contracts;
- Alberta Government enacted curtailment rules;
- changes in depletion and depreciation expense as a result of changes in production rates, future development costs and uncertainty of future benefits associated with specific non-core assets;
- exploration expense associated with discontinued exploration and evaluation activities in certain non-core growth properties;
- a decrease in general and administrative expense due to reduction in staffing levels;
- changes in the Corporation's share price and the resulting impact on stock-based compensation; and
- planned turnaround and other maintenance activities affecting production.

20. ANNUAL SUMMARIES

Unaudited	2019	2018[1]	2017[1]	2016[1]	2015[1]	2014[1]
FINANCIAL *($millions unless specified)*						
Net earnings (loss)	(62)	(119)	166	(429)	(1,170)	(106)
Per share, diluted	(0.21)	(0.40)	0.57	(1.90)	(5.21)	(0.47)
Adjusted funds flow	726	180	374	(62)	49	791
Per share, diluted	2.41	0.60	1.29	(0.27)	0.22	3.52
Capital expenditures	198	622	502	140	314	1,314
Cash and cash equivalents	206	318	464	156	408	656
Working capital	123	290	313	96	363	526
Long-term debt	3,123	3,740	4,668	5,053	5,190	4,350
Shareholders' equity	3,853	3,886	3,964	3,287	3,678	4,768
BUSINESS ENVIRONMENT						
WTI (US$/bbl)	57.03	64.77	50.95	43.33	48.80	93.00
Differential – WTI:WCS – Edmonton (US$/bbl)	(12.76)	(26.31)	(11.98)	(13.84)	(13.52)	(19.40)
Differential – WTI:AWB – Edmonton (US$/bbl)	(14.95)	(29.99)	(14.09)	(16.40)	(16.69)	(23.58)
AWB – Edmonton (US$/bbl)	42.08	34.78	36.86	26.93	32.11	69.42
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	(1.77)	(6.68)	(7.61)	(11.53)	(8.53)	(10.08)
AWB – U.S. Gulf Coast (US$/bbl)	55.26	58.09	43.34	31.80	40.27	82.92
C$ equivalent of 1US$ – average	1.3269	1.2962	1.2980	1.3256	1.2788	1.1047
Natural gas – AECO ($/mcf)	1.92	1.62	2.29	2.25	2.71	4.50
OPERATIONAL **($/bbl unless specified)**						
Blend sales, net of purchased product – bbls/d	134,223	125,368	115,766	116,586	117,132	97,334
Diluent usage – bbls/d	(40,637)	(38,317)	(35,766)	(36,159)	(36,167)	(30,092)
Bitumen sales – bbls/d	93,586	87,051	80,000	80,427	80,965	67,242
Bitumen production – bbls/d	93,082	87,731	80,774	81,245	80,025	71,186
Steam-oil ratio (SOR)	2.22	2.19	2.31	2.29	2.47	2.48
Blend sales	61.29	53.47	51.39	38.19	42.14	76.11
Cost of diluent	(8.08)	(16.78)	(9.36)	(10.28)	(11.43)	(13.35)
Bitumen realization	53.21	36.69	42.03	27.91	30.71	62.76
Transportation and storage – net	(10.84)	(8.42)	(6.89)	(6.46)	(4.82)	(1.38)
Third-party curtailment credits	(0.37)	—	—	—	—	—
Royalties	(1.30)	(1.20)	(0.77)	(0.29)	(0.70)	(4.36)
Operating costs – non-energy	(4.61)	(4.62)	(4.62)	(5.62)	(6.54)	(8.02)
Operating costs – energy	(2.38)	(1.98)	(2.98)	(3.01)	(3.84)	(6.30)
Power revenue	1.75	1.51	0.76	0.64	0.99	2.26
Realized gain (loss) on commodity risk management	(3.31)	(4.37)	(0.39)	0.08	—	—
Cash operating netback	32.15	17.61	27.14	13.25	15.80	44.96
Power sales price (C$/MWh)	56.70	47.87	21.49	18.74	27.48	48.83
Power sales (MW/h)	121	114	118	115	121	129
Average cost of diluent ($/bbl of diluent)	79.89	91.60	72.32	61.06	67.72	105.94
Average cost of diluent as a % of WTI	106%	106%	109%	106%	109%	103%
Depletion and depreciation rate per bbl of production	20.90	14.12	16.13	16.81	16.00	14.57
General and administrative expense per bbl of production	1.99	2.58	2.94	3.24	4.06	4.29
COMMON SHARES						
Shares outstanding, end of period (000)	299,508	296,841	294,104	226,467	224,997	223,847
Common share price ($) - close (end of period)	7.39	7.71	5.14	9.23	8.02	19.55

(1) *The Corporation adopted IFRS 16 Leases, effective January 1, 2019, therefore prior periods have not been restated.*

Consolidated Balance Sheet
(Unaudited, expressed in millions of Canadian dollars)

As at	Note		March 31, 2020		December 31, 2019
Assets					
Current assets					
Cash and cash equivalents	16	**$**	**62**	$	206
Trade receivables and other			**229**		382
Inventories	3		**32**		93
Risk management	18		**445**		—
			768		681
Non-current assets					
Property, plant and equipment	4		**6,140**		6,206
Exploration and evaluation assets	5		**124**		490
Other assets	6		**234**		227
Risk management	18		**1**		—
Deferred income tax asset	7		**264**		262
Total assets		**$**	**7,531**	$	7,866
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities		**$**	**247**	$	379
Interest payable			**30**		74
Current portion of provisions and other liabilities	9		**30**		28
Risk management	18		**90**		77
			397		558
Non-current liabilities					
Long-term debt	8		**3,212**		3,123
Provisions and other liabilities	9		**325**		332
Risk management	18		**4**		—
Total liabilities			**3,938**		4,013
Shareholders' equity					
Share capital	10		**5,443**		5,443
Contributed surplus			**188**		182
Deficit			**(2,085)**		(1,801)
Accumulated other comprehensive income			**47**		29
Total shareholders' equity			**3,593**		3,853
Total liabilities and shareholders' equity		**$**	**7,531**	$	7,866

Commitments and contingencies (Note 20)

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss)
(Unaudited, expressed in millions of Canadian dollars, except per share amounts)

Three months ended March 31	Note		2020		2019
Revenues					
Petroleum revenue, net of royalties	12	$	642	$	896
Other revenue	12		23		23
Total revenues			665		919
Expenses					
Diluent and transportation	13		380		391
Operating expenses			68		69
Inventory impairment	3		29		—
Purchased product			176		196
Third-party curtailment credits			(2)		—
Depletion and depreciation	4, 6		124		115
Exploration expense	5		366		—
General and administrative			16		18
Stock-based compensation	11		(13)		(5)
Net finance expense	15		70		78
Other expenses			8		10
Gain on asset dispositions	6		(6)		(12)
Risk management (gain) loss, net	18		(535)		230
Foreign exchange (gain) loss, net	14		270		(78)
Loss before income taxes			(286)		(93)
Income tax expense (recovery)			(2)		(45)
Net loss			(284)		(48)
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment			18		(4)
Comprehensive loss		$	(266)	$	(52)
Net loss per common share					
Basic	17	$	(0.95)	$	(0.16)
Diluted	17	$	(0.95)	$	(0.16)

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Changes in Shareholders' Equity
(Unaudited, expressed in millions of Canadian dollars)

	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2019	**$ 5,443**	**$ 182**	**$ (1,801)**	**$ 29**	**$ 3,853**
Stock-based compensation	**—**	**6**	**—**	**—**	**6**
Comprehensive income (loss)	**—**	**—**	**(284)**	**18**	**(266)**
Balance as at March 31, 2020	**$ 5,443**	**$ 188**	**$ (2,085)**	**$ 47**	**$ 3,593**
Balance as at December 31, 2018	$ 5,427	$ 170	$ (1,751)	$ 39	$ 3,885
IFRS 16 opening deficit adjustment	—	—	12	—	12
Stock-based compensation	—	5	—	—	5
Comprehensive income (loss)	—	—	(48)	(4)	(52)
Balance as at March 31, 2019	$ 5,427	$ 175	$ (1,787)	$ 35	$ 3,850

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Cash Flow
(Unaudited, expressed in millions of Canadian dollars)

Three months ended March 31	Note	2020	2019
Cash provided by (used in):			
Operating activities			
Net loss		**$ (284)**	$ (48)
Adjustments for:			
Deferred income tax expense (recovery)		**(2)**	(46)
Inventory impairment	3	**29**	—
Depletion and depreciation	4, 6	**124**	115
Exploration expense	5	**366**	—
Stock-based compensation	11	**5**	4
Unrealized net (gain) loss on foreign exchange	14	**267**	(77)
Unrealized (gain) loss on commodity risk management	18	**(429)**	209
Amortization of debt discount and debt issue costs	8	**2**	6
Gain on asset dispositions	6	**(6)**	(12)
Other		**2**	3
Decommissioning expenditures	9	**(2)**	—
Net change in other liabilities		**(3)**	(3)
Funds flow from operating activities		**69**	151
Net change in non-cash working capital items	16	**30**	(220)
Net cash provided by (used in) operating activities		**99**	(69)
Investing activities			
Capital expenditures	4	**(54)**	(53)
Net proceeds on dispositions	6	**6**	12
Net change in non-cash working capital items	16	**(11)**	(43)
Net cash provided by (used in) investing activities		**(59)**	(84)
Financing activities			
Issue of 7.125% senior unsecured notes	8	**1,581**	—
Repayment and redemption of long-term debt	8	**(1,723)**	(4)
Debt redemption premium	8	**(29)**	—
Refinancing costs	8	**(19)**	—
Payments on leased liabilities	16	**(6)**	(4)
Net cash provided by (used in) financing activities		**(196)**	(8)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**12**	(3)
Change in cash and cash equivalents		**(144)**	(164)
Cash and cash equivalents, beginning of period		**206**	318
Cash and cash equivalents, end of period		**$ 62**	$ 154

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

All amounts are expressed in millions of Canadian dollars unless otherwise noted.

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange under the symbol "MEG". The Corporation owns a 100% interest in over 750 square miles of mineral leases in the southern Athabasca region of Alberta and is primarily engaged in sustainable *in situ* thermal oil production at its Christina Lake Project.

The corporate office is located at 600 – 3rd Avenue SW, Calgary, Alberta, Canada.

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements (“interim consolidated financial statements”) were prepared using the same accounting policies and methods as those used in the Corporation’s audited consolidated financial statements for the year ended December 31, 2019. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting (“IAS 34”). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board ("IASB"), has been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation’s accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 4 of the Corporation’s audited consolidated financial statements for the year ended December 31, 2019. These interim consolidated financial statements should be read in conjunction with the Corporation’s audited consolidated financial statements for the year ended December 31, 2019.

There are no comparable recent events that provide guidance as to the effect the COVID-19 global pandemic may have, and as a result, the ultimate impact of the outbreak is highly uncertain and subject to change. The full extent of the impact of COVID-19 on the Corporation’s operations and future financial performance is currently unknown. The continued impact on capital and financial markets on a macro-scale presents uncertainty and risk with respect to the Corporation's performance, and estimates and assumptions used in the preparation of its financial results.

Additional estimates, assumptions and judgments in response to the COVID-19 global pandemic have been disclosed in these interim consolidated financial statements regarding valuation assessments related to the Corporation's inventories, property, plant and equipment, exploration and evaluation assets, long-term pipeline linefill, decommissioning provision and deferred income tax asset.

These interim consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation’s functional currency and were approved by the Corporation’s Audit Committee on May 4, 2020.

3. INVENTORIES

As at	March 31, 2020	December 31, 2019
Bitumen blend	**$ 25**	$ 73
Diluent	**—**	13
Material and supplies	**7**	7
	$ 32	$ 93

In light of the significant and acute decline in commodity prices associated with the COVID–19 global pandemic, inventory impairment charges were recorded related to the decline in value of the Corporation’s bitumen blend and diluent inventories of $19 million and $10 million, respectively. The inventory is measured at the lower of cost and net realizable value. The uncertainty surrounding the duration and depth of unprecedented low commodity prices, combined with significant volatility in commodity prices increases the estimation uncertainty associated with the net realizable value at March 31, 2020.

4. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Right-of-use assets	Corporate assets	Total
Cost					
Balance as at December 31, 2019	$ 9,077	$ 159	$ 263	$ 78	$ 9,577
Additions	54	—	14	—	68
Dispositions	(3)	(71)	—	—	(74)
Lease modification	—	—	4	—	4
Change in decommissioning liabilities	(9)	—	—	—	(9)
Balance as at March 31, 2020	**$ 9,119**	**$ 88**	**$ 281**	**$ 78**	**$ 9,566**
Accumulated depletion and depreciation					
Balance as at December 31, 2019	$ 3,199	$ 102	$ 25	$ 45	$ 3,371
Depletion and depreciation	116	1	6	1	124
Dispositions	(3)	(70)	—	—	(73)
Lease modification	—	—	4	—	4
Balance as at March 31, 2020	**$ 3,312**	**$ 33**	**$ 35**	**$ 46**	**$ 3,426**
Carrying amounts					
Balance as at December 31, 2019	$ 5,878	$ 57	$ 238	$ 33	$ 6,206
Balance as at March 31, 2020	**$ 5,807**	**$ 55**	**$ 246**	**$ 32**	**$ 6,140**

Included in the cost of property, plant and equipment is $242 million of assets under construction as at March 31, 2020 (December 31, 2019 – $229 million).

In light of the significant degradation and volatility in global crude oil prices, international oil supply and demand imbalances, and the uncertainty surrounding the economic impact of the COVID–19 global pandemic, the Corporation has determined that indicators of impairment existed as at March 31, 2020. A test for impairment was performed at the cash generating unit ("CGU") level by comparing the estimated recoverable amount to the carrying values of the assets, and as a result, there was no impairment to be recognized.

Estimating the recoverable amount of the Corporation's CGU involves several assumptions and estimates which are subject to estimation uncertainty, as well as a significant degree of judgment. Significant estimates involved in the calculation include pricing assumptions, production and cost assumptions and the appropriate discount rate. The Corporation engages GLJ Petroleum Consultants Ltd. ("GLJ") to prepare an annual reserve report, which contains the pricing, production and cost assumptions that form the basis for determining the recoverable amount. The report is prepared as at December 31, 2019, and therefore adjustments were made to reflect the updated commodity pricing as at April 1, 2020 as provided by GLJ. Other adjustments to the report are made as necessary to reflect the change in the economic environment. The appropriate discount rate requires a significant amount of judgment, and a sensitivity analysis was performed to ensure that a 1-2% change in the discount rate did not affect the conclusion reached that no impairment was required.

5. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2019	$	490
Additions		—
Exploration expense		(366)
Dispositions		—
Balance as at March 31, 2020	**$**	**124**

The Corporation has discontinued exploration and evaluation activities at this time in certain non-core growth properties and as such the associated land lease and evaluation costs totaling $366 million have been charged to exploration expense during the three months ended March 31, 2020. This is a result of focusing on the development of core assets to manage the business through an unpredictable global downturn including unknown duration, coupled with a steady shift away from near term growth. The remaining assets were allocated to the related CGU for impairment testing and no impairment was required.

6. OTHER ASSETS

As at		March 31, 2020		December 31, 2019
Non-current pipeline linefill[(a)]	**$**	**199**	$	190
Finance sublease receivables		**18**		18
Intangible assets[(b)]		**8**		9
Deferred financing costs		**6**		7
Prepaid transportation costs[(c)]		**9**		9
		240		233
Less current portion		**(6)**		(6)
	$	**234**	$	227

a. Non-current pipeline linefill on third-party owned pipelines is classified as a non-current asset as these transportation contracts expire between the years 2025 and 2048.

   In light of the significant and acute decline in commodity prices associated with the COVID–19 global pandemic, long-term pipeline linefill was tested for impairment under IAS 2 by comparing the carrying value to the net realizable value, and no impairment was recorded due to the long-term nature of the transportation contracts. The uncertainty surrounding the duration and depth of unprecedented low commodity prices, combined with significant volatility in commodity prices increases the estimation uncertainty associated with the net realizable value at March 31, 2020, and actual results could differ from the estimates.

b. As at March 31, 2020, intangible assets consist of $8 million invested in software that is not an integral component of the related computer hardware (December 31, 2019 – $9 million). Depreciation of $1 million was recognized for the three months ended March 31, 2020 (December 31, 2019 – $2 million). During the three months ended March 31, 2020, the Corporation sold patents that were recorded at a nominal amount, and recognized a gain on asset dispositions of $6 million. During the first quarter of 2019, the Corporation sold internally generated emission performance credits that were recorded at a nominal amount, and recognized a gain on asset dispositions of $12 million.

c. Prepaid transportation costs related to upgrading third-party transportation infrastructure have been capitalized and are being amortized to transportation expense over the 30-year term of the agreement.

7. DEFERRED INCOME TAX ASSET

As at March 31, 2020, the Corporation recognized a deferred tax asset of $264 million (December 31, 2019 - $262 million). The deferred tax asset is reviewed at each balance sheet date to assess whether it is probable that the related tax benefit will be realized. As at March 31, 2020, the Corporation estimates that future taxable income is expected to be sufficient to realize the deferred tax asset. The estimates used to determine future taxable income are subject to measurement uncertainty and actual results could differ from estimates.

8. LONG-TERM DEBT

As at	March 31, 2020	December 31, 2019
Second Lien:		
6.5% senior secured second lien notes (March 31, 2020 - US$496 million; December 31, 2019 - US$596 million; due 2025)	**$ 701**	$ 773
Unsecured:		
7.0% senior unsecured notes (March 31, 2020 - US$600 million; December 31, 2019 - US$1 billion; due 2024)	**847**	1,297
7.125% senior unsecured notes (March 31, 2020 - US$1.2 billion; December 31, 2019 - US$nil; due 2027)	**1,694**	—
6.375% senior unsecured notes (March 31, 2020 - US$nil; December 31, 2019 - US$800 million; due 2023)	**—**	1,037
	3,242	3,107
Less:		
Debt redemption premium	**—**	29
Unamortized deferred debt discount and debt issue costs	**(30)**	(13)
	$ 3,212	$ 3,123

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.4120 (December 31, 2019 – US$1 = C$1.2965).

During the three months ended March 31, 2020, the Corporation successfully closed a private offering of $1.6 billion (US$1.2 billion) in aggregate principal amount of 7.125% senior unsecured notes due February 2027. On February 18, 2020, the net proceeds of the offering, together with cash on hand, were used to:

- Fully redeem $1 billion (US$800 million) of the 6.375% senior unsecured notes due January 2023 at a redemption price of 101.063%;
- Partially redeem $530 million (US$400 million) of the US$1.0 billion 7.00% senior unsecured notes due March 2024 at a redemption price of 102.333%; and
- Pay $19 million in fees and expenses related to the offering.

Concurrent with the private offering, on February 18, 2020, the Corporation redeemed $132 million (US$100 million) in aggregate principal amount of its 6.5% senior secured second lien notes due January 2025 at a redemption price of 104.875%. Cash on hand was used to fund this senior secured second lien notes partial redemption.

Each of the redemptions described above include prepayment options whereby the Corporation is required to make an estimate at each reporting date of the likelihood of the prepayment option being exercised. Given the January 31, 2020 closing date, prepayment options were recognized at December 31, 2019 under IAS 10 Events After the Reporting Period, as an adjusting subsequent event. For the year ended December 31, 2019, the Corporation recognized a cumulative debt redemption premium of $29 million which was paid on January 31, 2020.

The Corporation has total available credit under two facilities of $1.3 billion, comprised of $800 million under the revolving credit facility and $500 million under its letter of credit facility, guaranteed by Export Development Canada ("EDC"). Letters of credit under the EDC facility do not consume capacity of the revolving credit facility. The revolving credit facility and the EDC Facility have a maturity date of July 30, 2024. The maturity dates of the revolving credit facility and the EDC Facility include a feature that would cause the maturity dates to spring back to 91 days prior to the maturity date of certain material debt of the Corporation if such debt has not been repaid or refinanced prior to such date.

The revolving credit facility does not contain a financial maintenance covenant unless the Corporation is drawn under the revolving credit facility in excess of $400 million. If the facility is drawn in excess of $400 million, the Corporation is required to maintain a first lien net debt to last twelve months earnings before interest, tax, depreciation and amortization ratio of 3.50 or less. The financial maintenance covenant, if triggered, will be tested quarterly. Issued letters of credit are not included in the calculation of the ratio.

The revolving credit facility, EDC facility and senior secured second lien notes are secured by substantially all the assets of the Corporation.

As at March 31, 2020, the Corporation had $787 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $63 million of unutilized capacity under the $500 million letter of credit facility. A letter of credit of $13 million was issued under the revolving credit facility in the first quarter of 2020.

9. PROVISIONS AND OTHER LIABILITIES

As at		March 31, 2020		December 31, 2019
Lease liabilities[(a)]	**$**	**288**	$	281
Decommissioning provision[(b)]		**62**		71
Other liabilities		**5**		8
Provisions and other liabilities		**355**		360
Less current portion		**(30)**		(28)
Non-current portion	**$**	**325**	$	332

a. Lease liabilities:

As at		March 31, 2020		December 31, 2019
Balance, beginning of period	**$**	**281**	$	131
IFRS 16 opening balance sheet adjustment		**—**		160
Additions		**14**		13
Modifications		**(4)**		(4)
Payments		**(9)**		(45)
Interest expense		**6**		26
Balance, end of period		**288**		281
Less current portion		**(24)**		(22)
Non-current portion	**$**	**264**	$	259

The Corporation's minimum lease payments are as follows:

As at March 31		2020
Within one year	$	48
Later than one year but not later than five years		150
Later than five years		521
Minimum lease payments		719
Amounts representing finance charges		(431)
Net minimum lease payments	$	288

The Corporation has short-term leases with lease terms of twelve months or less as well as low-value leases. As these lease costs are incurred they are recognized as either general and administrative expense or operating expense depending on their nature. As at March 31, 2020, the present value of these arrangements is $2 million (December 31, 2019 - $2 million), using the Corporation's estimated incremental borrowing rate.

b. Decommissioning provision:

The following table presents the decommissioning provision associated with the reclamation and abandonment of the Corporation’s property, plant and equipment and exploration and evaluation assets:

As at		March 31, 2020		December 31, 2019
Balance, beginning of period	$	71	$	65
Changes in estimated life and estimated future cash flows		1		(2)
Changes in discount rates		(10)		2
Liabilities incurred and disposed, net		—		1
Liabilities settled		(2)		(2)
Accretion		2		7
Balance, end of period		62		71
Less current portion		(6)		(6)
Non-current portion	$	56	$	65

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The total undiscounted amount of the estimated future cash flows to settle the decommissioning obligations is $816 million (December 31, 2019 – $827 million). Due to the significant decline in global crude oil prices and increased levels of market volatility, the Corporation’s estimated weighted average credit-adjusted risk free rate increased 1.8% during the three months ended March 31, 2020. As at March 31, 2020, the Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 15.5% (December 31, 2019 – 13.7%) and an inflation rate of 2.1% (December 31, 2019 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2019 - periods up to the year 2066).

10. SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares.

Changes in issued common shares are as follows:

	Three months ended March 31, 2020			Year ended December 31, 2019		
	Number of shares (thousands)		Amount	Number of shares (thousands)		Amount
Balance, beginning of year	**299,508**	**$**	**5,443**	296,841	$	5,427
Issued upon exercise of stock options	**39**		**—**	266		2
Issued upon vesting and release of RSUs and PSUs	**—**		**—**	2,401		14
Balance, end of period	**299,547**	**$**	**5,443**	299,508	$	5,443

11. STOCK-BASED COMPENSATION

Three months ended March 31		**2020**		**2019**
Cash-settled expense[i]	**$**	**(18)**	$	(9)
Equity-settled expense		**5**		4
Stock-based compensation	**$**	**(13)**	$	(5)

(i) *Cash-settled RSUs and PSUs are accounted for as liability instruments and are measured at fair value based on the market value of the Corporation's common shares at each period end and certain estimates including a performance multiplier for PSUs. Fluctuations in the fair value are recognized during the period in which they occur.*

The value of cash-settled share-based units decreased in the three months ended March 31, 2020 due to the decrease in the Corporation's share price. As at March 31, 2020, the Corporation recognized a liability of $6 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2019 – $25 million). The current portion of $5 million is included within accounts payable and accrued liabilities and $1 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards.

12. REVENUES

Three months ended March 31		**2020**		**2019**
Sales from:				
Production	**$**	**469**	$	696
Purchased product[i]		**179**		203
Petroleum revenue	**$**	**648**	$	899
Royalties		**(6)**		(3)
Petroleum revenue, net of royalties	**$**	**642**	$	896
Power revenue	**$**	**20**	$	20
Transportation revenue		**3**		3
Other revenue	**$**	**23**	$	23
Total revenues	**$**	**665**	$	919

(i) *The associated third-party purchases are included in the consolidated statement of earnings (loss) and comprehensive income (loss) under the caption "Purchased product".*

a. Disaggregation of revenue from contracts with customers

The Corporation recognizes revenue upon delivery of goods and services in the following geographic regions:

	Three months ended March 31					
	2020			2019		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	**$ 308**	**$ 31**	**$ 339**	$ 431	$ 145	$ 576
United States	**161**	**148**	**309**	265	58	323
	$ 469	**$ 179**	**$ 648**	$ 696	$ 203	$ 899

Other revenue recognized during the three months ended March 31, 2020 and 2019 is attributed to Canada.

b. Revenue-related assets

The Corporation has recognized the following revenue-related assets in trade receivables and other:

As at	March 31, 2020	December 31, 2019
Petroleum revenue	**$ 108**	$ 122
Other revenue	**4**	4
Total revenue-related assets	**$ 112**	$ 126

Revenue-related receivables are typically settled within 30 days. As at March 31, 2020 and December 31, 2019, there was no material expected credit loss required against revenue-related receivables.

13. DILUENT AND TRANSPORTATION

Three months ended March 31	2020	2019
Diluent expense	**$ 300**	$ 297
Transportation and storage	**80**	94
Diluent and transportation	**$ 380**	$ 391

14. FOREIGN EXCHANGE (GAIN) LOSS, NET

Three months ended March 31	2020	2019
Unrealized foreign exchange (gain) loss on:		
Long-term debt	$ 278	$ (79)
US$ denominated cash and cash equivalents	(11)	2
Unrealized net (gain) loss on foreign exchange	267	(77)
Realized (gain) loss on foreign exchange	3	(1)
Foreign exchange (gain) loss, net	$ 270	$ (78)

C$ equivalent of 1 US$		
Beginning of period	1.2965	1.3646
End of period	1.4120	1.3360

15. NET FINANCE EXPENSE

Three months ended March 31	2020	2019
Interest expense on long-term debt	$ 64	$ 72
Interest expense on lease liabilities	6	7
Interest income	(2)	(2)
Net interest expense	68	77
Accretion on provisions	2	1
Net finance expense	$ 70	$ 78

16. SUPPLEMENTAL CASH FLOW DISCLOSURES

Three months ended March 31		2020		2019
Cash provided by (used in):				
Trade receivables and other	**$**	**165**	$	(233)
Inventories[(a)]		**34**		(9)
Accounts payable and accrued liabilities		**(136)**		37
Interest payable	**$**	**(44)**	$	(58)
	$	**19**	$	(263)
Changes in non-cash working capital relating to:				
Operating	**$**	**30**	$	(220)
Investing		**(11)**		(43)
	$	**19**	$	(263)
Cash and cash equivalents:[(b)]				
Cash	**$**	**62**	$	154
Cash equivalents		**—**		—
	$	**62**	$	154
Cash interest paid	**$**	**105**	$	118

a. Excludes a non-cash inventory impairment of $29 million recognized as at March 31, 2020. The impairment is related to the significant decline in oil prices and will be realized in the second quarter of 2020 through funds flow from operating activities.

b. As at March 31, 2020, $45 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (March 31, 2019 – $43 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.4120 (March 31, 2019 – US$1 = C$1.3360).

The following table provides a reconciliation of assets and liabilities to cash flows arising from financing activities:

		Finance sublease receivables		**Lease liabilities**		**Long-term debt**
Balance as at December 31, 2019	$	18	$	281	$	3,123
Cash changes:						
Payments on lease liabilities		—		(9)		—
Issue of 7.125% senior unsecured notes		—		—		1,581
Repayment and redemption of long-term debt		—		—		(1,723)
Debt redemption premium		—		—		(29)
Refinancing costs		—		—		(19)
Non-cash changes:						
Lease liabilities incurred		—		14		—
Lease liabilities modified		—		(4)		—
Interest expense on lease liabilities		—		6		—
Unrealized (gain) loss on foreign exchange		—		—		278
Amortization of deferred debt discount and debt issue costs		—		—		1
Balance as at March 31, 2020	**$**	**18**	**$**	**288**	**$**	**3,212**

(i) Finance sublease receivables, Lease liabilities & Long-term debt all include their respective current portion.

17. NET LOSS PER COMMON SHARE

Three months ended March 31		2020		2019
Net loss	$	(284)	$	(48)
Weighted average common shares outstanding (millions)[a]		300		297
Dilutive effect of stock options, RSUs and PSUs (millions)[b]		—		—
Weighted average common shares outstanding – diluted (millions)		300		297
Net loss per share, basic	$	(0.95)	$	(0.16)
Net loss per share, diluted	$	(0.95)	$	(0.16)

a. Weighted average common shares outstanding for the three months ended March 31, 2020 includes 381,014 PSUs vested not yet released (three months ended March 31, 2019 - nil).

b. For the three months ended March 31, 2020, the Corporation incurred a net loss and therefore there was no dilutive effect of stock options, RSUs and PSUs. If the Corporation had recognized net earnings for the three months ended March 31, 2020, the dilutive effect of stock options, RSUs and PSUs would have been 4.6 million weighted average common shares (three months ended March 31, 2019 - 3.2 million weighted average common shares).

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments recognized on the consolidated balance sheet are comprised of cash and cash equivalents, trade receivables and other, risk management contracts, accounts payable and accrued liabilities, interest payable and long-term debt.

a. Fair values:

The carrying value of cash and cash equivalents, trade receivables and other risk management contracts, accounts payable and accrued liabilities and interest payable included on the consolidated balance sheet approximate the fair value of the respective assets and liabilities due to the short-term nature of those instruments.

The following fair values are based on Level 2 inputs to fair value measurement:

As at	March 31, 2020				December 31, 2019			
		Carrying amount		Fair value		Carrying amount		Fair value
Recurring measurements:								
Financial assets								
Risk management contracts	$	377	$	377		—		—
Financial liabilities								
Long-term debt (Note 8)	$	3,242	$	1,737	$	3,107	$	3,160
Risk management contracts	$	25	$	25	$	77	$	77

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker. Due to the significant decline in global crude oil prices and increased levels of market volatility, the estimated fair value of the Corporation's long-term debt significantly decreased as at March 31, 2020. The fair values were determined based on estimates as at March 31, 2020 and are expected to continue to fluctuate given the volatility in the debt and commodity price markets.

The fair value of risk management contracts is derived using third-party valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including forward prices for commodities, interest rate yield curves and foreign exchange rates. The observable inputs may be adjusted using certain methods, which include extrapolation to the end of the term of the contract.

b. Risk management:

The Corporation enters into derivative financial instruments to manage risk. The use of the financial risk management contracts is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes. Financial risk management contracts are measured at fair value, with gains and losses on re-measurement included in the consolidated statement of earnings and comprehensive income in the period in which they arise.

The Corporation had the following financial commodity risk management contracts relating to crude oil sales and condensate purchases outstanding as at March 31, 2020:

As at March 31, 2020	**Volumes (bbls/d)(i)**	**Term**	**Average Price (US$/bbl)(i)**
Crude Oil Sales Contracts			
WTI(ii) Fixed Price	66,103	Apr 1, 2020 - Jun 30, 2020	$57.75
WTI(ii) Fixed Price	17,965	Jul 1, 2020 - Dec 31, 2020	$59.37
WTI:WCS(iii) Fixed Differential	33,681	Apr 1, 2020 - Jun 30, 2020	$(18.67)
WTI:WCS(iii) Fixed Differential	24,500	Jul 1, 2020 - Dec 31, 2020	$(20.46)
Enhanced Fixed Price with Sold Put Option			
WTI Fixed Price/Sold Put Option Strike Price	20,685	Jul 1, 2020 - Dec 31, 2020	$59.22 / $52.00
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	7,250	Apr 1, 2020 - Dec 31, 2020	$(7.63)
WTI:Mont Belvieu Fixed Differential	10,950	Jan 1, 2021 - Dec 31, 2021	$(10.37)
WTI:Mont Belvieu Fixed Differential	200	Jan 1, 2022 - Dec 31, 2022	$(11.30)
WTI:Mont Belvieu Fixed % of WTI	7,750	Apr 1, 2020 - Dec 31, 2020	93.1 %

(i) The volumes and prices in the above table represent averages for various contracts with differing terms and prices. The average price and percentages for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.
(ii) West Texas Intermediate ("WTI") crude oil
(iii) Western Canadian Select ("WCS") crude oil blend

The Corporation's financial commodity risk management contracts are subject to master agreements that create a legally enforceable right to offset, by counterparty, the related financial assets and financial liabilities on the Corporation's balance sheet in all circumstances.

The following table provides a summary of the Corporation's unrealized offsetting financial risk management positions:

As at	March 31, 2020			December 31, 2019		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Gross amount	**$ 446**	**$ (25)**	**$ 421**	$ —	$ (77)	$ (77)
Amount offset	**(69)**	**—**	**(69)**	—	—	—
Net amount	**$ 377**	**$ (25)**	**$ 352**	$ —	$ (77)	$ (77)
Current portion	**$ 445**	**$ (90)**	**$ 355**	$ —	$ (77)	$ (77)
Non-current portion	**1**	**(4)**	**(3)**	—	—	—
Net amount	**$ 446**	**$ (94)**	**$ 352**	$ —	$ (77)	$ (77)

The following table provides a reconciliation of changes in the fair value of the Corporation's financial risk management assets and liabilities from January 1 to March 31:

As at March 31	2020	2019
Fair value of contracts, beginning of year	$ (77)	$ 93
Fair value of contracts realized	106	21
Change in fair value of contracts	323	(230)
Amortized premiums on put options	—	—
Fair value of contracts, end of period	**$ 352**	$ (116)

The following table summarizes the financial commodity risk management gains and losses:

Three Months Ended March 31	2020	2019
Realized loss (gain) on commodity risk management	**$ (106)**	$ 21
Unrealized loss (gain) on commodity risk management	**(429)**	209
Commodity risk management loss (gain)	**$ (535)**	$ 230

The following table summarizes the sensitivity of the earnings (loss) before income tax impact of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place as at March 31, 2020:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	**$ (70)**	**$ 68**
Crude oil differential price (i)	± US$5.00 per bbl applied to WTI:WCS differential contracts	**$ 53**	**$ (53)**

(i) As the WCS differential is expressed as a discount to WTI, an increase in the differential results in a lower WCS price and a decrease in the differential results in a higher WCS price.

The Corporation entered into the following financial commodity risk management contracts relating to crude oil sales and condensate purchases subsequent to March 31, 2020. As a result, these contracts are not reflected in the Corporation's Consolidated Financial Statements:

Subsequent to March 31, 2020	Volumes (bbls/d)[(i)]	Term	Average Prices (US$/bbl)[(i)]
Crude Oil Sales (Purchase) Contracts			
WTI Fixed Price	(6,833)	Apr 1, 2020 - Apr 30, 2020	$22.00
WTI Fixed Price	6,613	May 1, 2020 - May 31, 2020	$25.45
WTI Fixed Price	10,000	Jul 1, 2020 - Sept 30, 2020	$32.37

(i) The volumes and prices in the above tables represent averages for various contracts with differing terms and prices. The average *price and percentages for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.*

c. Equity price risk management:

Equity price risk is the risk that changes in the Corporation's own share price impact earnings and cash flows. Earnings and funds flow from operating activities are impacted when outstanding cash-settled RSUs and PSUs, issued under the Corporation's stock-based compensation plans, are revalued each period based on the Corporation's share price. Net cash provided by (used in) operating activities is impacted when these stock-based compensation units are ultimately settled. The Corporation enters into financial derivative contracts ("share price contracts") to manage these risks.

d. Credit risk management:

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward looking information to determine the appropriate loss allowance provisions. Credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to each counterparty's credit quality. A substantial portion of accounts receivable are with investment grade customers in the energy industry and are subject to normal industry credit risk. The Corporation has experienced no material loss in relation to trade receivables. As at March 31, 2020, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $223 million. All amounts receivable from commodity risk management activities are due from large Canadian banks with strong investment grade credit ratings. Counterparty default risk associated with the Corporation's commodity risk management activities is also partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in note 24 of the Corporation's 2019 annual consolidated financial statements.

The Corporation's cash balances are used to fund the development of its properties. As a result, the primary objectives of the investment portfolio are low risk capital preservation and high liquidity. The cash balances are held in high interest savings accounts or are invested in high grade, liquid, short-term instruments such as bankers' acceptances, commercial paper, money market deposits or similar instruments. The cash and cash equivalents balance at March 31, 2020 was $62 million. None of the investments are past their maturity or considered impaired. The Corporation's estimated maximum exposure to credit risk related to its cash and cash equivalents is $62 million.

e. Liquidity risk management:

Liquidity risk is the risk that the Corporation will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk that the Corporation cannot generate sufficient cash flow from the Christina Lake Project or is unable to raise further capital in order to meet its obligations under its debt agreements. The lenders are entitled to exercise any and all remedies available under the debt agreements. The Corporation manages its liquidity risk through the active management of cash, debt and revolving credit facilities and by maintaining appropriate access to credit.

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. Meeting current and future obligations through the uncertainty associated with the COVID–19 global pandemic is supported by the Corporation's financial framework including a strong commodity risk management program securing cash flow through 2020 and credit risk management policies minimizing exposure related to customer receivables primarily to investment grade customers in the energy industry. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary.

The Corporation's earliest maturing long-term debt is four years out, represented by US$600 million of senior unsecured notes due March 2024. None of the Corporation’s outstanding long-term debt contain financial maintenance covenants. Additionally, the Corporation's modified covenant-lite $800 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $400 million. If drawn in excess of $400 million, the Corporation is required to maintain a quarterly first lien net leverage ratio (first lien net debt to last twelve-month EBITDA) of 3.5 or less. Under the Corporation's credit facility, first lien net debt is calculated as debt under the credit facility plus other debt that is secured on a *pari passu* basis with the credit facility, less cash on hand.

19. CAPITAL MANAGEMENT

The Corporation's capital consists of cash and cash equivalents, debt and shareholders' equity. The Corporation's objective for managing capital is to prioritize balance sheet strength while maintaining flexibility to repay debt, fund sustaining capital, return capital to shareholders or fund future production growth. In the current price environment, management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. Debt repayment and sustaining capital expenditure activities are anticipated to be funded by the Corporation's adjusted funds flow, cash on hand and/or other available liquidity.

On January 31, 2020, the Corporation closed the refinancing and extension of the maturity profile of its debt portfolio. Following completion of the associated transactions, MEG's first debt maturity was extended to 2024. As at March 31, 2020, the Corporation had $787 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $63 million of unutilized capacity under the $500 million letter of credit facility. A letter of credit of $13 million was issued under its revolving credit facility in the first quarter of 2020.

The following table summarizes the Corporation's net debt:

As at	Note	March 31, 2020	December 31, 2019
Long-term debt	8	**$ 3,212**	$ 3,123
Cash and cash equivalents		**(62)**	(206)
Net debt		**$ 3,150**	$ 2,917

Net debt is an important measure used by management to analyze leverage and liquidity. During the three months ended March 31, 2020, net debt increased by $233 million primarily due to the weakening of the Canadian dollar relative to the US dollar partially offset by the partial redemption of its 6.5% senior secured second lien notes.

On January 31, 2020 the Corporation successfully closed a private offering of $1.6 billion (US$1.2 billion) in aggregate principal amount of 7.125% senior unsecured notes due February 2027. On February 18, 2020, the net proceeds of the offering, together with cash on hand, were used to:

- Fully redeem $1 billion (US$800 million) of the 6.375% senior unsecured notes due January 2023 at a redemption price of 101.063%;
- Partially redeem $530 million (US$400 million) of the US$1.0 billion 7.00% senior unsecured notes due March 2024 at a redemption price of 102.333%; and
- Pay $19 million in fees and expenses related to the offering.

Concurrent with the private offering, on February 18, 2020, the Corporation redeemed $132 million (US$100 million) in aggregate principal amount of its 6.5% senior secured second lien notes due January 2025 at a redemption price of 104.875%. Cash on hand was used to fund this senior secured second lien notes partial redemption.

The following table summarizes the Corporation's funds flow from (used in) operations and adjusted funds flow:

Three months ended March 31	Note	2020	2019
Net cash provided by (used in) operating activities		$ 99	$ (69)
Net change in non-cash operating working capital items		(30)	220
Funds flow from (used in) operations		69	151
Adjustments:			
Contract cancellation		7	—
Decommissioning expenditures	9	2	—
Adjusted funds flow		$ 78	$ 151

Management utilizes funds flow from (used in) operations and adjusted funds flow as a measure to analyze operating performance and cash flow generating ability. Funds flow from (used in) operations and adjusted funds flow impacts the level and extent of debt repayment, funding for capital expenditures and returning capital to shareholders. By excluding changes in non-cash working capital, non-recurring items and decommissioning expenditures from cash flows, the funds flow from (used in) operations and adjusted funds flow measures provide meaningful metrics for management by establishing a clear link between the Corporation's cash flows and the operating netbacks from the Christina Lake Project. Funds flow from (used in) operations and adjusted funds flow are not intended to represent net cash provided by (used in) operating activities.

Net debt, funds flow from (used in) operations and adjusted funds flow are not standardized measures and may not be comparable with the calculation of similar measures by other companies.

20. COMMITMENTS AND CONTINGENCIES

a. Commitments

The Corporation's commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at March 31, 2020:

	2020	2021	2022	2023	2024	Thereafter	Total
Transportation and storage[i]	$ 303	$ 443	$ 433	$ 475	$ 458	$ 6,069	$ 8,181
Diluent purchases	109	23	23	19	—	—	174
Other operating commitments	11	13	12	12	10	42	100
Variable office lease costs	4	5	5	5	5	34	58
Capital commitments	3	—	—	—	—	—	3
Commitments	**$ 430**	**$ 484**	**$ 473**	**$ 511**	**$ 473**	**$ 6,145**	**$ 8,516**

(i) This represents transportation and storage commitments from 2020 to 2048, including the Access Pipeline TSA, and pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet (Note 9(a)).

b. Contingencies

The Corporation is involved in various legal claims associated with the normal course of operations. The Corporation believes that any liabilities that may arise pertaining to such matters would not have a material impact on its financial position.

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility in Alberta. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation filed a statement of defense in the first quarter of 2018. The Corporation continues to view this claim as without merit and will continue to defend against all such claims. The Corporation believes that any liabilities that might arise from this matter are unlikely to have a material effect on its financial position.