MEG ENERGY

Sustainable. Innovative. Responsible.

2019 Report to Shareholders, Management's Discussion and Analysis and Annual Financial Statements

For the year ended December 31, 2019

TSX | MEG

Report to Shareholders for the year ended December 31, 2019

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

MEG Energy Corp. reported full year 2019 operational and financial results on March 4, 2020. Highlights include:

- Free cash flow of $528 million driven by adjusted funds flow of $726 million ($2.41 per share) and disciplined capital spend of $198 million;
- Bitumen production volumes of 93,082 barrels per day (bbls/d) at a steam-oil-ratio (SOR) of 2.22;
- Net operating costs of $5.24 per barrel, supported by record low non-energy operating costs of $4.61 per barrel and strong power sales which had the impact of offsetting 74% of per barrel energy operating costs resulting in a net energy operating cost of $0.63 per barrel;
- Average AWB blend sales price net of transportation and storage costs at Edmonton of US$42.20 per barrel which was better than the posted 2019 AWB index price of US$42.08 per barrel, notwithstanding 43% Enbridge mainline apportionment, highlighting the value of MEG's North American marketing strategy;
- General and administrative expense of $68 million which was $15 million, or 18%, lower than 2018;
- During 2019 MEG amended and restated its existing credit facilities to have new 5-year terms and repaid $501 million of outstanding long-term debt. Cash cost savings expected from the reduction in credit fees and interest savings on debt repaid in 2019 are $45 million annually; and
- Subsequent to year end, 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. The combination of these transactions is neutral to ongoing cash costs.

"As we entered 2019, we stated that we would continue to improve overall cost efficiencies, preserve financial liquidity and enhance MEG's competitive position" says Derek Evans, President and Chief Executive Officer. "Since making that commitment to shareholders MEG has repaid $633 million of long-term debt, entered into a new modified-covenant-lite 5-year credit facility, refinanced US$1.2 billion of existing indebtedness, significantly reduced ongoing G&A expense and posted record low annual non-energy operating costs. We remain committed to driving efficiencies in our business from a financial, operational and cost perspective and will continue to direct all available free cash flow to debt repayment."

Financial Liquidity and Debt Repayment

Maintaining long term financial liquidity while aggressively pursuing ongoing debt repayment remains MEG's top priority.

Since the beginning of 2019 the Corporation has repaid $633 million (US$479 million) of long-term debt including $501 million (US$379 million) of long-term debt in 2019 and an additional $132 million (US$100 million) subsequent to year end. This was accomplished through the repayment of the senior secured term loan balance of $297 million (US$225 million) and the repurchase and extinguishment of $336 million (US$254 million) aggregate principal amount of 6.5% senior secured second lien notes.

Additionally, in July 2019 the Corporation entered into a new 5-year revolving credit facility and letter of credit facility. The total borrowing capacity available under the two facilities was proactively reduced to $1.3 billion, comprised of $800 million under the revolving credit facility and $500 million under the letter of credit facility. The facilities contain no financial maintenance covenants unless MEG has drawn in excess of $400 million under the revolving credit facility.

Cash cost savings from the reduction in credit fees and interest savings on debt repaid in 2019 are expected to be $45 million annually.

In January 2020, the Corporation successfully closed a private offering of US$1.2 billion in aggregate principal amount of 7.125% senior unsecured notes due February 2027. The net proceeds of the offering plus cash-on-hand were used to fully redeem US$800 million of the 6.375% senior unsecured notes due January 2023 and partially redeem US$400 million of the US$1.0 billion 7.0% senior unsecured notes due March 2024. Post this refinancing, MEG has a 4-year runway until its next debt maturity represented by the remaining US$600 million of March 2024 notes.

Blend Sales Pricing and North American Market Access

MEG realized an average AWB blend sales price of US$46.19 per barrel in 2019 compared to US$41.25 per barrel in 2018. The average WTI price decreased US$7.74 per barrel year over year, but this was more than offset by the US$15.04 per barrel narrowing of the average WTI:AWB differential at Edmonton. Also contributing to the realized AWB blend sales price in 2019 was the Corporation's ability to deliver 33% of its blend sales volumes to the U.S. Gulf Coast ("USGC"), where the WTI:AWB differential averaged US$1.77 per barrel. Comparatively, in 2018 the Corporation delivered 30% of its blend sales volumes to the USGC when the average WTI:AWB differential was US$6.68 per barrel.

Transportation and storage costs averaged US$5.70 per barrel of AWB blend sales in 2019 compared to US$4.51 per barrel of AWB blend sales in 2018. The higher costs in 2019 reflect the increased use of rail transportation. In 2019, 15% of total blend sales volumes were transported by rail compared to 6% of total blend sales volumes transported by rail in 2018. Also contributing to the increased costs in 2019 was the sale of the Access Pipeline that occurred in March 2018, which increased transportation costs from that point forward.

Excluding transportation and storage costs upstream of the Edmonton index sales point, MEG's net AWB blend sales price at Edmonton averaged US$42.20 per barrel in 2019 compared to the posted AWB index price at Edmonton of US$42.08. Notwithstanding that Enbridge mainline apportionment averaged 43% during 2019, 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. MEG's average pricing against the AWB index price at Edmonton is expected to improve further once MEG's contracted capacity on the Flanagan and Seaway pipeline system doubles to 100,000 bbls/d of blend in mid-2020.

MEG's AWB blend sales by rail in 2019 were 19,686 bbls/d compared to 7,857 bbls/d in 2018 as the Corporation ramped up rail utilization beginning in the fourth quarter of 2018 as Edmonton WTI:AWB differentials supported increased rail usage. 42% of sales by rail in 2019 were delivered to the USGC compared to 52% in 2018, with the remainder sold at Edmonton.

Operational Performance

Bitumen production averaged 94,566 bbls/d in the fourth quarter of 2019, contributing to a 6% increase in annual production in 2019 of 93,082 bbls/d compared to 87,731 bbls/d in 2018. The annual increase is primarily due to the impact of turnaround activities in 2018. Production in 2019 was impacted by curtailment limits imposed by the Government of Alberta, which the Corporation was partially able to mitigate through third-party curtailment credits, allowing MEG to produce at levels above its government-mandated limits.

Annual net operating costs in 2019 averaged $5.24 per barrel, a 3% increase compared to 2018, directly impacted by higher natural gas purchase prices which were partially offset by higher sales of surplus power from MEG's cogeneration facilities. Non-energy operating costs averaged a record low of $4.61 per barrel as the Corporation continues to drive efficiency gains into its operations while maintaining production levels. Net operating costs during the fourth quarter of 2019 were higher than the fourth quarter of 2018 mainly as a result of higher energy costs.

General and administrative ("G&A") expense was $68 million, or $1.99 per barrel of production, in 2019 compared to $83 million, or $2.58 per barrel of production, in 2018. The $15 million decrease in aggregate G&A year over year is primarily due to the reduction of staffing levels and rationalization of ongoing administrative costs.

Adjusted Funds Flow and Net Loss

MEG's bitumen realization averaged $53.21 per barrel in 2019 compared to $36.69 per barrel in 2018. The increase is mainly due to the significant narrowing of the WTI:AWB differential, particularly at Edmonton. The narrowing differential also resulted in a higher recovery of diluent expense through blend sales, which lowered the Corporation's cost of diluent.

The improved bitumen realization resulted in MEG's cash operating netback increasing to $32.15 per barrel in 2019 from $17.61 per barrel in 2018. The higher cash operating netback drove the increase in adjusted funds flow from $180 million in 2018 to $726 million in 2019.

The Corporation realized a net loss of $62 million in 2019 compared to a net loss of $119 million in 2018. The net loss in 2019 was related to various non-cash items including one-time accelerated depreciation charges recognized in the second quarter of 2019 as the Corporation's strategy shifted away from production growth to debt repayment and an unrealized loss on commodity risk management contracts, partially offset by an unrealized foreign exchange gain.

Capital Expenditures

Capital expenditures in 2019 totaled $198 million compared to $622 million in 2018. Capital expenditures in 2019 were primarily directed towards sustaining and maintenance activities, as well as advancing work already underway on the Phase 2B brownfield facility expansion. As previously announced, the expansion includes incremental steam generation, water handling and oil treating capacity, and is expected to be completed in the second quarter of 2020.

Outlook

Announced in November 2019, MEG's capital investment plan for 2020 of $250 million includes $210 million to be directed towards sustaining and maintenance capital and $20 million to be directed towards the completion of the in-progress Phase 2B brownfield expansion expected to be completed in the second quarter of 2020. The remaining $20 million of capital spending is required for non-discretionary field infrastructure, regulatory and corporate capital costs.

The Corporation's 2020 annual average bitumen production volumes are targeted to be in the range of 94,000 - 97,000 bbls/d which includes the impact of a plant turnaround planned for the third quarter of 2020. In response to the Alberta Government's Special Production Allowance ("SPA") program announcement on October 31, 2019 for curtailed producers, the Corporation began ramping up its productive capacity and expects to reach its full 100,000 bbls/d production capacity subsequent to the planned turnaround.

For the first half of 2020, MEG has entered into benchmark WTI fixed price swaps for approximately 70% of forecast first half 2020 production volumes at an average price of US$59.15 per barrel. On a full year basis, MEG has hedged approximately 55% of forecast 2020 production via benchmark WTI fixed price swaps and WTI fixed price swaps with sold put options. Additionally, the Corporation has hedged approximately 30% of its WTI:WCS differential exposure at an average price of (US$19.39) per barrel and approximately 50% of condensate exposure at an average price of 101% of WTI. The table below reflects MEG's current 2020 financial and physical hedge positions.

			Forecast Period		
	Q1 2020	Q2 2020	Q3 2020	Q4 2020	FY 2020
WTI Hedges					
WTI Fixed Price Hedges					
Volume (bbls/d)	72,899	62,395	19,043	16,887	**42,806**
Weighted average fixed WTI price (US$/bbl)	$ 58.67	$ 59.68	$ 59.38	$ 59.36	**$ 59.19**
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 / $52.00**
Total WTI hedge volume (bbls/d)	**72,899**	**62,395**	**35,913**	**41,387**	**53,148**
WTI:WCS Differential Hedges					
Volume(2) (bbls/d)	30,150	45,150	32,150	39,150	**36,650**
Weighted average fixed WTI:WCS differential at Edmonton (US$/bbl)	$ (20.14)	$ (18.50)	$ (19.79)	$ (19.49)	**$ (19.39)**
Condensate Hedges					
Volume(3) (bbls/d)	19,149	23,298	23,208	23,208	**22,216**
Average % of WTI landed in Edmonton	103%	101%	100%	100%	**101%**

(1) *Includes fixed price swaps 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$59.30 per barrel. Illustratively, at an average 2H20 WTI price of US$50.00 and US$45.00 per barrel, MEG's effective WTI hedged price for 2H20 is US$58.22 and US$55.55 per barrel, respectively.*

(2) *2020 includes approximately 13,200 bbls/d of physical forward rail blend sales at a fixed WTI:AWB differential.*

(3) *2020 includes approximately 7,250 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.*

The Corporation's 2020 non-energy operating costs and general and administrative expense are targeted to be in the range of $4.50 - $4.90 per barrel and $1.75 - $1.85 per barrel, respectively.

ADVISORY

Forward-Looking Information

This report contains forward-looking information and should be read in conjunction with the "Forward-Looking Information" contained within the Advisory section of this annual 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 December 31		Year ended December 31	
($millions)	**2019**	2018	**2019**	2018
Net cash provided by (used in) operating activities	**$ 225**	$ 94	**$ 631**	$ 280
Net change in non-cash operating working capital items	**(52)**	(159)	**110**	(111)
Funds flow from (used in) operations	**173**	(65)	**741**	169
Adjustments:				
Other income[(1)]	**(20)**	—	**(20)**	—
Decommissioning expenditures	**1**	1	**2**	5
Net change in other liabilities[(2)]	**3**	3	**3**	3
Realized gain on foreign exchange derivatives[(3)]	**—**	—	**—**	(35)
Defense costs related to unsolicited bid[(4)]	**—**	19	**—**	19
Payments on onerous contracts	**—**	5	**—**	19
Adjusted funds flow	**$ 157**	$ (37)	**$ 726**	$ 180
Capital expenditures	**(72)**	(144)	**(198)**	(622)
Free cash flow	**$ 85**	$ (181)	**$ 528**	$ (442)

(1) *During the fourth quarter of 2019, the Corporation agreed to relieve the Alberta Petroleum Marketing Commission ("APMC") of all obligations pursuant to a crude oil purchase and sale agreement in exchange for a payment of $20 million.*

(2) *Excludes change in long-term cash-settled stock-based compensation liability.*

(3) *A gain related to the settlement of forward currency contracts to manage the foreign exchange risk on Canadian dollar denominated proceeds related to the sale of assets designated for U.S. dollar denominated long-term debt repayment.*

(4) *The Corporation incurred costs of $19 million in the fourth quarter of 2018 related to Husky Energy Inc.'s unsolicited bid to acquire all of the outstanding shares of the Corporation.*

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, 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 year ended December 31, 2019 was approved by the Corporation's Board of Directors on March 4, 2020. This MD&A should be read in conjunction with the Corporation's audited annual consolidated financial statements and notes thereto for the year ended December 31, 2019 and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the audited 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 Access Western Blend ("AWB" or "blend") 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.

During 2019, the Corporation received regulatory approval for its Surmont Project from the Alberta Energy Regulator ("AER"). In connection with the planning of its 2020 capital program, and consistent with its strategic focus on continued application of all free cash flow to debt reduction, the Corporation elected to move the Surmont Project out of its current development plan. Accordingly, 709 million barrels of gross probable undeveloped reserves at Surmont have been reclassified as contingent resources in the GLJ report as at December 31, 2019.

The Christina Lake Project, which contains all of the Corporation's 2P reserves has regulatory approval in place for 210,000 bbls/d of production. To date, the Corporation has developed production capacity of approximately 100,000 bbls/d at its Christina Lake Project through the implementation of three major projects, as well as low-cost debottlenecking and expansion projects, and the application of its proprietary reservoir technologies. The average annual production decline rate at the Christina Lake Project is approximately 10% to 15% and at the current productive capacity, the Corporation has a 2P reserve life index of approximately 60 years.

The Corporation has been able to realize production growth at the Christina Lake Project while minimizing GHG emissions through the application of its proprietary technologies. Specifically, the Corporation's enhanced Modified Steam and Gas Push ("eMSAGP") technology reduces the amount of steam required to produce a barrel of bitumen. Furthermore, the Corporation continues to test its proprietary technology, known as enhanced Modified VAPour EXtraction ("eMVAPEX"), at the Christina Lake Project, which involves the targeted injection of light hydrocarbons in replacement of steam. The Corporation also uses cogeneration, also known as combined heat and power generation, to create steam and power from a single heat source. The application of eMSAGP and cogeneration have enabled MEG to lower its GHG intensity approximately 20% below the *in situ* industry average calculated based on data reported to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. By applying the eMSAGP process to significant portions of the Christina Lake Project, MEG achieved an average steam oil ratio of 2.2 in 2019 compared to the *in situ* industry average of 3.1.

The Corporation delivers its production to market via a long-term transportation services agreement on the Access Pipeline, which connects to the Edmonton, Alberta sales hub, and via additional pipelines, storage facilities and rail infrastructure to transport, store and sell AWB to refiners throughout North America and internationally. MEG has contracted for 50,000 bbls/d (expanding to 100,000 bbls/d in July 2020) of AWB transportation capacity on the Flanagan South and Seaway pipeline systems, providing pipeline transportation directly to U.S. Gulf Coast ("USGC") refineries and export terminals. The Corporation is also a shipper on the Trans Mountain Expansion Project which, when in service, will provide 20,000 bbls/d of committed tidewater access for AWB on Canada's West Coast. Additionally, the Corporation secured a 30,000 bbls/d rail loading commitment at the Bruderheim Terminal for three years, expiring at the end of 2021, with a 1-year extension option. The Corporation has also contracted oil storage capacity of 2.8 million barrels in Alberta and strategic locations in the U.S. with marine export capacity associated with certain USGC terminals. This combination of pipeline access, committed rail capacity, storage capacity and marine export capacity advances MEG's strategy of having long-term and reliable market access to world oil prices for its production.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

Consistent with the Corporation's strategic focus on maintaining long-term financial liquidity while pursuing ongoing debt repayment, significant accomplishments during 2019 include:

- The Corporation amended and restated its revolving credit facility and its Export Development Canada ("EDC") letter of credit facility and extended the maturity date of each facility by 2.75 years to July 30, 2024. The total borrowing capacity available under the two facilities was reduced to $1.3 billion, comprised of $800 million under the revolving credit facility and $500 million under the letter of credit facility;
- Since the first quarter of 2019 the Corporation has repaid $633 million (US$479 million) of long-term debt including $501 million (US$379 million) of long-term debt in 2019 and an additional $132 million (US$100 million) subsequent to year end. This was accomplished through the repayment of the senior secured term loan balance of $297 million (US$225 million) and the repurchase and extinguishment of the 6.5% senior secured second lien notes due January 2025 of $204 million (US$154 million) during the second half of 2019 and $132 million (US $100 million) subsequent to year end;
- On January 31, 2020, the Corporation successfully closed a private offering of US$1.2 billion in aggregate principal amount of 7.125% senior unsecured notes due February 2027. The net proceeds of the offering, together with cash on hand, were used to fully redeem US$800 million in aggregate principal amount of 6.375% senior unsecured notes due January 2023 and partially redeem US$400 million of the US$1.0 billion aggregate principal amount of 7.0% senior unsecured notes due March 2024; and
- Concurrent with the private offering, the Corporation redeemed 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.

The Corporation currently expects annual interest and credit fee savings resulting from the refinancings and debt repayments to be approximately $45 million annually.

The Corporation expects to continue to repay outstanding indebtedness as free cash flow becomes available.

Adjusted funds flow in 2019 was $726 million compared to $180 million in 2018, reflecting a higher cash operating netback of $32.15 per barrel in 2019 compared to $17.61 per barrel in 2018. Contributing to the improved cash operating netback was improved AWB pricing at both Edmonton and the USGC, combined with a lower cost of diluent during 2019.

Annual bitumen production averaged 93,082 bbls/d in 2019 compared to 87,731 bbls/d in 2018. The 6% increase in annual average production volumes was primarily due to the impact of turnaround activities during 2018. Commencing January 1, 2019, the Government of Alberta enacted rules to limit the production of crude oil and bitumen, which impacted the Corporation's 2019 annual bitumen production. The Corporation was able to mitigate the impact of these production limits throughout the year by actively purchasing third-party curtailment credits, which allowed the Corporation to produce at levels above its mandated limits. Production curtailment limits are set by the Government of Alberta on a monthly basis and are expected to continue throughout 2020.

The Corporation recognized a net loss of $62 million in 2019 compared to a net loss of $119 million in 2018. The decrease is due to an unrealized foreign exchange gain and a higher cash operating netback in 2019, partially offset by an unrealized loss on commodity risk management.

On November 21, 2019, the Corporation announced its 2020 capital investment plan, including a capital budget of $250 million, which it expects to be fully funded by adjusted funds flow. In announcing its 2020 capital investment plan, the Corporation confirmed it remains committed to applying all available cash in excess of its 2020 capital investment plan to further debt reduction. The Corporation is estimating 2020 non-energy operating costs and general and administrative costs to be in the range of $4.50 - $4.90 per barrel and $1.75 - $1.85 per barrel, respectively. Bitumen production is expected to average 94,000 - 97,000 bbls/d, which includes the impact of a planned turnaround in the third quarter of 2020. In response to the Government of Alberta’s Special Production Allowance (“SPA”) announcement on October 31, 2019 for curtailed producers, the Corporation began ramping up its productive capacity and expects to reach its full 100,000 bbl/d production capacity subsequent to the planned turnaround.

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:

	Three months ended December 31		**Year ended December 31**	
($millions, except as indicated)	**2019**	**2018**	**2019**	**2018**
Bitumen production - bbls/d	**94,566**	87,582	**93,082**	87,731
Steam-oil ratio	**2.27**	2.22	**2.22**	2.19
Bitumen sales - bbls/d	**94,347**	88,283	**93,587**	87,051
Bitumen realization - $/bbl	**46.86**	15.31	**53.21**	36.69
Net operating costs - $/bbl(1)	**5.87**	4.55	**5.24**	5.09
Non-energy operating costs - $/bbl	**4.49**	4.25	**4.61**	4.62
Cash operating netback - $/bbl(2)	**28.33**	7.14	**32.15**	17.61
Adjusted funds flow(3)	**157**	(37)	**726**	180
Per share, diluted	**0.51**	(0.13)	**2.41**	0.60
Revenue	**992**	520	**3,931**	2,733
Net earnings (loss)	**26**	(199)	**(62)**	(119)
Per share, diluted	**0.09**	(0.67)	**(0.21)**	(0.40)
Capital expenditures	**72**	144	**198**	622
Cash and cash equivalents	**206**	318	**206**	318
Long-term debt - C$	**3,123**	3,740	**3,123**	3,740
Long-term debt - US$	**2,409**	2,741	**2,409**	2,741

(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 26 of the 2019 audited annual consolidated financial statements for further details.

3. FOURTH QUARTER OF 2019

Bitumen production in the fourth quarter of 2019 averaged 94,566 bbls/d compared to 87,582 bbls/d in the same period in 2018. During the fourth quarter of 2018, the Corporation voluntarily curtailed production to mitigate the effects of the significant widening of the WTI:WCS differential.

Adjusted funds flow for the three months ended December 31, 2019 was $157 million compared to a negative adjusted funds flow of $37 million in the same period of 2018. The increase is due to a higher cash operating netback of $28.33 per barrel during the three months ended December 31, 2019 compared to $7.14 per barrel during the three months ended December 31, 2018. Contributing to the improved cash operating netback was higher bitumen realization due to the positive impact of a significantly narrower WTI:WCS differential on AWB blend sales and lower cost of diluent during the three months ended December 31, 2019.

The following table is provided to reconcile the Corporation's net cash provided by operating activities to adjusted funds flow for the fourth quarters of 2019 and 2018:

Three months ended December 31		**2019**		**2018**
Net cash provided by (used in) operating activities	**$**	**225**	$	94
Net change in non-cash operating working capital items		**(52)**		(159)
Funds flow from (used in) operations		**173**		(65)
Adjustments:				
Other income(1)		**(20)**		—
Decommissioning expenditures		**1**		1
Net change in other liabilities(2)		**3**		3
Defense costs related to unsolicited bid(3)		**—**		19
Payments on onerous contracts		**—**		5
Adjusted funds flow	**$**	**157**	$	(37)

(1) *During the fourth quarter of 2019, the Corporation agreed to relieve the Alberta Petroleum Marketing Commission ("APMC") of all obligations pursuant to a crude oil purchase and sale agreement in exchange for a payment of $20 million.*

(2) *Excludes change in long-term cash-settled stock-based compensation liability.*

(3) *The Corporation incurred costs of $19 million in the fourth quarter of 2018 related to Husky Energy Inc.'s unsolicited bid to acquire all of the outstanding shares of the Corporation.*

The Corporation recognized net earnings of $26 million for the three months ended December 31, 2019 compared to a net loss of $199 million for the three months ended December 31, 2018. The increase is due to a higher cash operating netback, driven by stronger benchmark pricing, and an unrealized foreign exchange gain associated with the strengthening of the Canadian dollar partially offset by an unrealized loss on commodity risk management associated with the narrowing of the WTI:WCS differential.

During the fourth quarter of 2019, the Corporation repurchased and extinguished an additional $107 million (US$81 million) in aggregate principal amount of its 6.5% senior secured second lien notes with cash on hand, increasing the total repurchase and extinguishment of senior secured second lien notes to $204 million (US$154 million) for the full year.

4. RESULTS OF ANNUAL OPERATIONS

Bitumen Production and Steam-Oil Ratio

	2019	2018
Bitumen production – bbls/d	**93,082**	87,731
Steam-oil ratio (SOR)	**2.22**	2.19

Bitumen Production

Average bitumen production for the year ended December 31, 2019 increased 6% compared to the same period of 2018. This was primarily due to the impact of turnaround activities during 2018, which included the advancement of planned 2019 turnaround activities into the fourth quarter of 2018 to manage the impact of a significantly wide WTI:WCS differential. No turnaround activities were completed in 2019, however production was impacted by the production curtailment limits imposed by the Government of Alberta. The Corporation was able to partially mitigate the impact of these production limits throughout the year by actively purchasing third-party curtailment credits, which allowed the Corporation to produce at levels above its mandated limits.

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 for this purpose 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 marginally increased for the year ended December 31, 2019 compared to the same period of 2018 as steam is operationally required to be injected into the reservoirs to maintain production capability notwithstanding the production limits from the Alberta Government mandated production curtailment program.

Adjusted Funds Flow

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:

($millions)		2019		2018
Net cash provided by (used in) operating activities	**$**	**631**	$	280
Net change in non-cash operating working capital items		**110**		(111)
Funds flow from (used in) operations		**741**		169
Adjustments:				
Other income(1)		**(20)**		—
Decommissioning expenditures		**2**		5
Net change in other liabilities(2)		**3**		3
Realized gain on foreign exchange derivatives(3)		**—**		(35)
Defense costs related to unsolicited bid(4)		**—**		19
Payments on onerous contracts		**—**		19
Adjusted funds flow	**$**	**726**	$	180

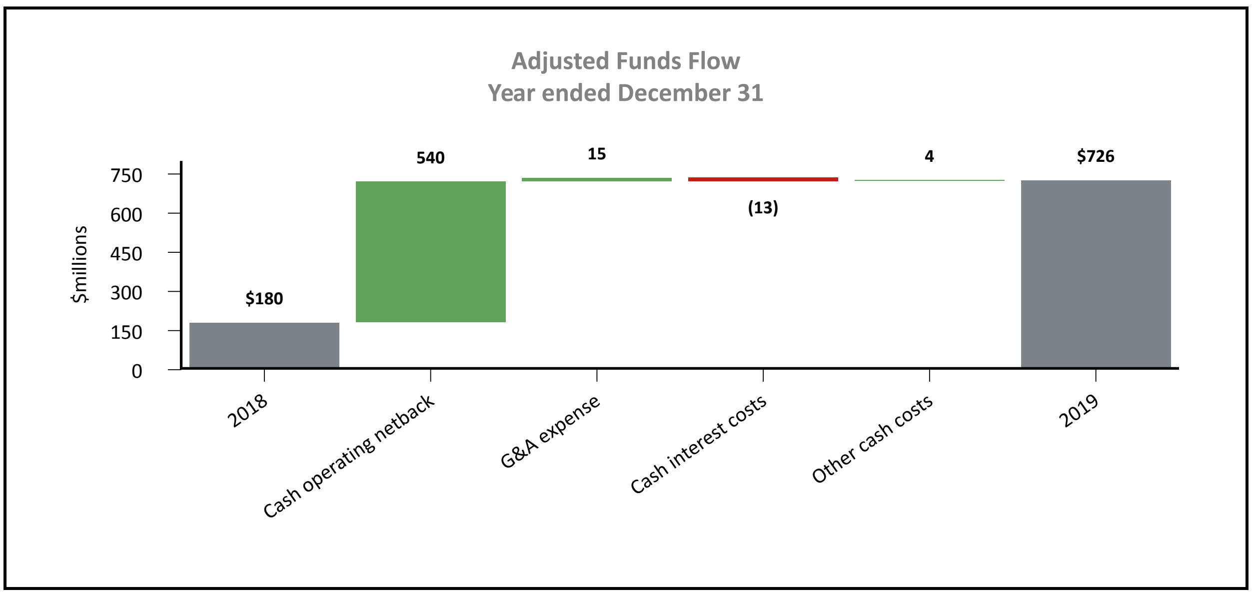
(1) *During the fourth quarter of 2019, the Corporation agreed to relieve the Alberta Petroleum Marketing Commission ("APMC") of all obligations pursuant to a crude oil purchase and sale agreement in exchange for a payment of $20 million.*

(2) *Excludes change in long-term cash-settled stock-based compensation liability.*

(3) *A gain related to the settlement of forward currency contracts to manage the foreign exchange risk on Canadian dollar denominated proceeds related to the sale of assets designated for U.S. dollar denominated long-term debt repayment.*

(4) *The Corporation incurred costs of $19 million in the fourth quarter of 2018 related to Husky Energy Inc.'s unsolicited bid to acquire all of the outstanding shares of the Corporation.*

Adjusted funds flow increased significantly during the year ended December 31, 2019 compared to the same period of 2018 driven by the Corporation's improved cash operating netback in 2019. The increase in the cash operating netback was due to a higher blend sales price and a lower cost of diluent.



Cash Operating Netback

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

	2019		2018	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Petroleum revenue[1]	**$ 3,903**		$ 2,711	
Purchased product	**(900)**		(264)	
Blend sales[2]	**3,003**	**61.29**	2,447	53.47
Cost of diluent	**(1,185)**	**(8.08)**	(1,281)	(16.78)
Bitumen realization	**1,818**	**53.21**	1,166	36.69
Transportation and storage[3]	**(370)**	**(10.84)**	(268)	(8.42)
Third-party curtailment credits[4]	**(13)**	**(0.37)**	—	—
Royalties	**(45)**	**(1.30)**	(38)	(1.20)
	1,390	**40.70**	860	27.07
Operating costs - non-energy	**(157)**	**(4.61)**	(147)	(4.62)
Operating costs - energy	**(81)**	**(2.38)**	(63)	(1.98)
Power revenue	**60**	**1.75**	48	1.51
Net operating costs	**(178)**	**(5.24)**	(162)	(5.09)
Cash operating netback - excludes realized commodity risk management	**1,212**	**35.46**	698	21.98
Realized gain (loss) on commodity risk management	**(113)**	**(3.31)**	(139)	(4.37)
Cash operating netback[5]	**$ 1,099**	**$ 32.15**	$ 559	$ 17.61
Bitumen sales volumes - bbls/d		**93,587**		87,051

(1) Petroleum revenue is before royalties and includes $907 million (2018 - $208 million) of sales from purchased oil products related to marketing asset optimization activities.

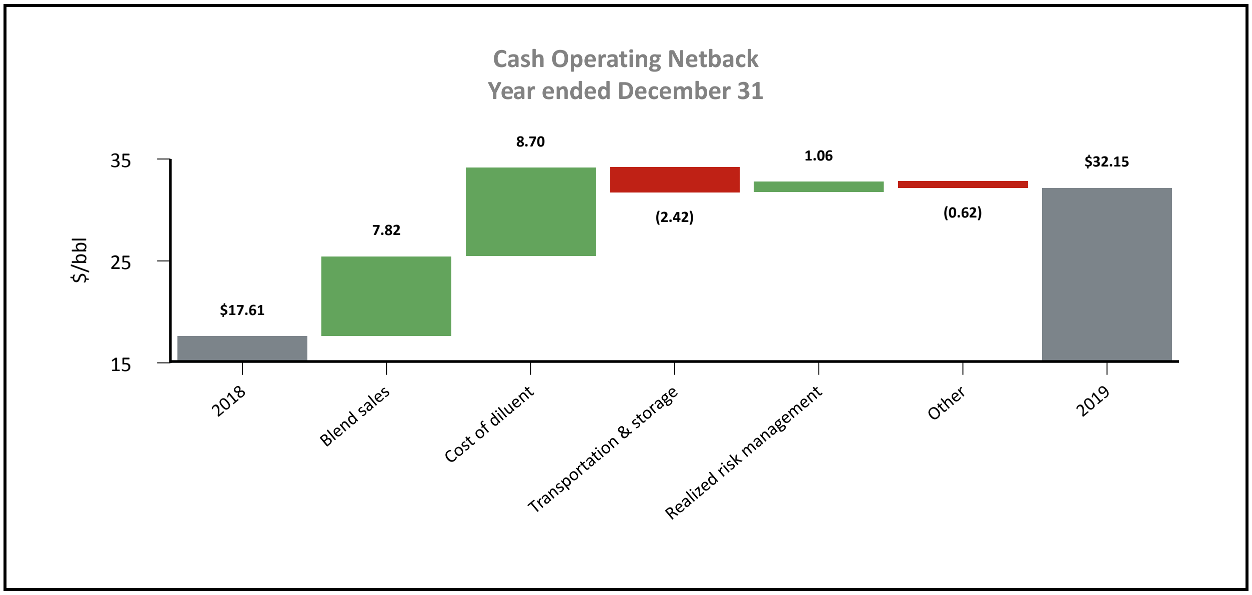
(2) Blend sales per barrel are based on blend sales volumes.

(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) Includes the cost of purchasing third-party curtailment credits to increase the Corporation's production above provincially-mandated curtailment levels.

(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 require 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 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.

	2019		**2018**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Petroleum revenue[1]	**$ 3,903**		$ 2,711	
Purchased product	**(900)**		(264)	
Blend sales[2]	**$ 3,003**	**$ 61.29**	$ 2,447	$ 53.47
Cost of diluent	**(1,185)**	**(8.08)**	(1,281)	(16.78)
Bitumen realization	**$ 1,818**	**$ 53.21**	$ 1,166	$ 36.69
Average Commodity Prices:		**$/bbl**		**$/bbl**
WTI (US$/bbl)		**$ 57.03**		$ 64.77
Differential – WTI:AWB – Edmonton (US$/bbl)		**(14.95)**		(29.99)
AWB – Edmonton (US$/bbl)		**$ 42.08**		$ 34.78
AWB – Edmonton (C$/bbl)		**$ 55.84**		$ 45.08
WTI (US$/bbl)		**$ 57.03**		$ 64.77
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)		**(1.77)**		(6.68)
AWB – U.S. Gulf Coast (US$/bbl)		**$ 55.26**		$ 58.09
AWB – U.S. Gulf Coast (C$/bbl)		**$ 73.32**		$ 75.30

(1) *Petroleum revenue is before royalties and includes $907 million (2018 - $209 million) of sales from purchased oil products related to marketing asset optimization activities.*
(2) *Blend sales per barrel are based on blend sales volumes.*

During the year ended December 31, 2019, the WTI price decreased but was more than offset by a significant narrowing of the WTI:AWB differential, particularly at Edmonton. As a result, the blend sales price increased by $7.82 per barrel and the cost of diluent decreased by $8.70 per barrel, reflecting a higher recovery of the diluent expense through blend sales. Together, these factors increased bitumen realization by $16.52 per barrel during the year ended December 31, 2019 compared to the same period of 2018.

Another factor increasing bitumen realization during the year ended December 31, 2019 was the Corporation's ability to sell more blend volumes into the higher priced USGC market. Approximately 33% of blend sales volumes were delivered to the USGC during the year ended December 31, 2019, compared to 30% in the same period of 2018. Refer to the Marketing Activity section of this MD&A for further details.

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.

	2019		**2018**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Transportation and storage	**$ (370)**	**$ (10.84)**	$ (268)	$ (8.42)

During the year ended December 31, 2019, transportation and storage costs per barrel increased 29%, compared to the same period of 2018. The increase in costs on a per barrel basis is primarily the result of increased blend volumes transported by rail which enables the Corporation to access the eastern USGC market and incremental transportation costs associated with the Access Pipeline Transportation Services Agreement entered into on March 22, 2018.

Third-party curtailment credits

On December 3, 2018 the Government of Alberta enacted rules to enable a temporary curtailment of crude oil and bitumen production (the "Curtailment Rules"). The Curtailment Rules came into force on January 1, 2019 and 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. This process is managed by the Alberta Energy Regulator who allocates the monthly production limits to each individual production company. Third-party curtailment credits exist when a producer chooses not to (or is unable to) produce up to its monthly allocated production limit and can transfer these unused credits to other producers seeking to increase their individual allocated production limit. As a result of the process, a secondary market has developed to transfer curtailment credits between industry producers.

	2019		**2018**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Third-party curtailment credits	**$ (13)**	**$ (0.37)**	$ —	$ —

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.

	2019		**2018**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Royalties	**$ (45)**	**$ (1.30)**	$ (38)	$ (1.20)

The increase in royalties for the year ended December 31, 2019, compared to the same period of 2018, is primarily due to higher bitumen realization, partially offset by a lower royalty rate due to lower WTI prices. Also a recovery was recognized in 2018 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.

	2019		2018	
($millions, except as indicated)		$/bbl		$/bbl
Operating costs - non-energy	**$ (157)**	**$ (4.61)**	$ (147)	$ (4.62)
Operating costs - energy	**(81)**	**(2.38)**	(63)	(1.98)
Power revenue	**60**	**1.75**	48	1.51
Net operating costs	**$ (178)**	**$ (5.24)**	$ (162)	$ (5.09)
Average natural gas purchase price (C$/mcf)		**$ 2.18**		$ 1.88
Average realized power sales price (C$/Mwh)		**$ 56.70**		$ 47.87

Net operating costs per barrel for the year ended December 31, 2019 increased 3% compared to the same period of 2018 due to a higher natural gas purchase price, partially offset by a higher power sales price.

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.

	2019		2018	
($millions, except as indicated)		$/bbl		$/bbl
Realized gain (loss) on commodity risk management	**$ (113)**	**$ (3.31)**	$ (139)	$ (4.37)

Realized losses were recognized in 2019 and 2018 due to the settlement of losses on commodity risk management contracts primarily relating to crude oil sales. 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:

	2019				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)
WTI	$ 57.03	$ 57.03	$ 57.03	$ 57.03	$ 57.03
Differential - WTI:AWB at sales point	(15.88)	(11.52)	(1.28)	(3.78)	(10.84)
Blend sales price	41.15	45.51	55.75	53.25	46.19
Transportation and storage[1]	(1.71)	(4.28)	(10.67)	(23.54)	(5.70)
Transportation and storage from Christina Lake to Edmonton[2]	1.71	1.71	1.71	1.71	1.71
Blend sales price, net of transportation & storage at Edmonton	$ 41.15	$ 42.94	$ 46.79	$ 31.42	$ 42.20
Total blend sales - bbls/d	78,421	11,459	36,116	8,227	134,223
% of total sales	58%	9%	27%	6%	100%

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 41.70	$ 55.28	$ 13.58
Transportation and storage[1]	(2.05)	(13.06)	(11.01)
Transportation and storage from Christina Lake to Edmonton[2]	1.71	1.71	—
Blend sales price, net of transportation & storage at Edmonton	$ 41.36	$ 43.93	$ 2.57

	2018				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)
WTI	$ 64.77	$ 64.77	$ 64.77	$ 64.77	$ 64.77
Differential - WTI:AWB at sales point	(30.89)	(36.00)	(6.27)	(1.83)	(23.52)
Blend sales price	33.88	28.77	58.50	62.94	41.25
Transportation and storage[1]	(1.33)	(5.48)	(9.86)	(23.34)	(4.51)
Transportation and storage from Christina Lake to Edmonton[2]	1.33	1.33	1.33	1.33	1.33
Blend sales price, net of transportation & storage at Edmonton	$ 33.88	$ 24.62	$ 49.97	$ 40.93	$ 38.07
Total blend sales - bbls/d	83,945	3,810	33,566	4,047	125,368
% of total sales	67%	3%	27%	3%	100%

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 33.66	$ 58.98	$ 25.32
Transportation and storage[1]	(1.51)	(11.31)	(9.80)
Transportation and storage from Christina Lake to Edmonton[2]	1.33	1.33	—
Blend sales price, net of transportation & storage at Edmonton	$ 33.48	$ 49.00	$ 15.52

(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$10.84 per barrel for the year ended December 31, 2019 compared to C$8.42 per barrel for the year ended December 31, 2018.*

(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 1.3269 for the year ended December 31, 2019 and 1.2962 for the year ended December 31, 2018.*

Excluding transportation and storage costs upstream of the Edmonton index sales point, the Corporation's blend sales price averaged US$42.20 per barrel during the year ended December 31, 2019 compared to the posted AWB benchmark price at Edmonton of US$42.08 per barrel. Notwithstanding that Enbridge Mainline apportionment averaged 43% during 2019, the Corporation was able to capture pricing in-line with 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 year ended December 31, 2019 averaged 134,223 bbls/d compared to 125,368 bbls/d for the year ended December 31, 2018. AWB transported by rail more than doubled to 15% of total blend sales volumes in 2019 compared to 6% in the same period of 2018 as the Corporation ramped up rail utilization. Utilization rates at the Bruderheim terminal steadily increased to 86% at the end of 2019.

Although WTI:WCS differentials at Edmonton narrowed significantly during the year ended December 31, 2019 compared to the same period of 2018, the Corporation increased its use of rail as a mechanism to clear barrels out of the Edmonton market due to continually high Enbridge mainline apportionment. The use of rail and storage assists in reducing the Corporation's exposure to the post–apportionment market at Edmonton. Beginning December 2019 the Government of Alberta introduced its SPA program, allowing the Corporation some curtailment relief equivalent to incremental increases in qualifying rail shipments out of Alberta.

The per barrel premium earned on blend sales is largely due to the Corporation's secured access to the USGC, where sales pricing is 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$2.57 per barrel premium to those sold at Edmonton during the year ended December 31, 2019. This compares to a US$15.52 per barrel premium at the USGC compared to Edmonton during the year ended December 31, 2018. The premium recognized during the year ended December 31, 2019 was lower than the same period of 2018 primarily due to the tighter WTI:AWB differential at Edmonton in 2019.

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.

($millions, except as indicated)		**2019**		2018
Sales from:				
Production	**$**	**2,996**	$	2,503
Purchased products[(1)]		**907**		208
Petroleum revenue	**$**	**3,903**	$	2,711
Royalties		**(45)**		(38)
Petroleum revenue, net of royalties	**$**	**3,858**	$	2,673
Power revenue	**$**	**60**	$	48
Transportation revenue		**13**		12
Other revenue	**$**	**73**	$	60
Total revenues	**$**	**3,931**	$	2,733

(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 2019, revenue increased 44% from 2018 primarily as a result of increased revenue from the sale of third-party purchased products, which totaled $907 million in 2019 compared to $208 million in 2018. The Corporation engages in the purchase and sale of third-party products to optimize the value of its marketing assets. Asset optimization activities focus 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. The Corporation does not engage in speculative trading. The purchase and sale of third-party products require the concurrent locking in of price risk pursuant to policies approved by the Board which can be achieved either through the counterparty or through financial price risk management.

Also contributing to the increased revenue was a 15% increase to the average blend sales price driven by the significant narrowing of the WTI:WCS differential from 2018 to 2019.

Net Earnings (Loss)

($millions, except per share amounts)		2019		2018
Net earnings (loss)	**$**	**(62)**	$	(119)
Per share, diluted	**$**	**(0.21)**	$	(0.40)

The net loss for the year ended December 31, 2019 decreased from 2018 primarily as a result of increased bitumen realization. Also impacting the net loss was an accelerated depreciation expense, after tax of $183 million and an exploration expense, after tax of $45 million as a result of the uncertainty of future benefits from certain non-core assets that do not contribute to the Corporation's development plan or cash flow. The Corporation also recognized an unrealized loss on commodity risk management contracts of $169 million offset by an unrealized foreign exchange gain of $172 million.

Comparatively, the net loss for the year ended December 31, 2018 included an unrealized foreign exchange loss of $341 million offset by an unrealized gain on commodity risk management contracts totaling $161 million. The 2018 net loss also included a gain on asset dispositions of $325 million related to the sale of the Corporation's 50% interest in the Access Pipeline and 100% interest in the Stonefell Terminal.

Capital Expenditures

($millions)		2019		2018[1]
Sustaining and maintenance	**$**	**115**	$	336
Phase 2B brownfield expansion		**46**		81
eMSAGP		**—**		90
eMVAPEX		**13**		65
Field infrastructure, corporate and other		**24**		50
	$	**198**	$	622

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

The decrease in capital spending reflects the completion of the eMSAGP project and lower overall spending in-line with the Corporation's 2019 capital budget of $200 million. Capital expenditures during the year ended December 31, 2019 were primarily directed towards sustaining and maintenance activities as well as advancing work already underway on the Phase 2B brownfield expansion.

5. OUTLOOK

Summary of 2019 Guidance	Guidance[1]	**Revised Guidance[2]**	**Annual Results**
Capital expenditures	$200 million	$200 million	$198 million
Bitumen production – annual average (bbls/d)	92,000 – 93,000	92,750 - 93,250	93,082
Non-energy operating costs ($/bbl)	$4.75 – $5.00	$4.61 - $4.65	$4.61
General and administrative expense ($/bbl)	$1.95 – $2.05	$1.98 - $2.00	$1.99

(1) *Guidance issued October 30, 2019.*

(2) *Revised guidance issued January 16, 2020.*

Capital expenditures for 2019 were $198 million and were in-line with the Corporation's capital expenditures guidance of $200 million. Over the course of 2019, the Corporation was successful in finding capital cost savings and undertaking minor scope changes that allowed the Corporation to deliver its original $200 million budget for approximately $170 million. As a result, based on operational benefits including plant integrity and turnaround management, the Corporation shifted approximately $30 million of expected 2020 capital expenditures into 2019 to accelerate the completion of the Corporation's in-progress brownfield project at the Phase 2B central processing facility which includes incremental steam generation, water handling and oil treating capacity. This project, which was initiated in 2018, is expected to be completed in the second quarter of 2020.

During 2019, the Corporation was able to purchase third-party curtailment credits, which had a positive impact on the Corporation's production and sales volumes. The Corporation was able to achieve annual average bitumen production of 93,082 bbls/d, average annual non-energy operating costs of $4.61 per barrel and average annual general and administrative expense of $1.99 per barrel, which were all consistent with the Corporation's most recent 2019 guidance.

Summary of 2020 Guidance	**Guidance[(1)]**
Capital expenditures	$250 million
Bitumen production – annual average (bbls/d)	94,000 - 97,000
Non-energy operating costs ($/bbl)	$4.50 - $4.90
General and administrative expense ($/bbl)	$1.75 - $1.85

(1) *Issued November 21, 2019.*

On November 21, 2019, the Corporation announced its 2020 capital investment plan, including a capital budget of $250 million which it expects to be fully funded by adjusted funds flow. In announcing its 2020 capital investment plan, the Corporation confirmed it remains committed to applying all available cash in excess of its 2020 capital investment plan to further debt reduction. The 2020 capital budget will direct $210 million towards sustaining and maintenance capital and $20 million towards completion of the in-progress brownfield project at the Phase 2B central processing facility which includes incremental steam generation, water handling and oil treating capacity. The Corporation expects to complete this project in the second quarter of 2020. The remaining $20 million of capital spending is required primarily for non-discretionary field infrastructure, regulatory and corporate capital costs.

The Corporation's 2020 annual average bitumen production volumes are targeted to be in the range of 94,000 - 97,000 bbls/d which includes the impact of a planned turnaround in the third quarter of 2020. In response to the Government of Alberta's SPA announcement on October 31, 2019 for curtailed producers, which enables some curtailment relief with increased rail shipments our of Alberta, the Corporation began ramping up its productive capacity and expects to reach its full 100,000 bbl/d production capacity subsequent to the planned turnaround.

The Corporation's 2020 non-energy operating costs and general and administrative expense are targeted to be in the range of $4.50 - $4.90 per barrel and $1.75 - $1.85 per barrel, respectively, as the Corporation continues to focus on reducing its cost structure.

6. SUSTAINABILITY

The Corporation is committed to providing the world with ethical and environmentally responsible Canadian oil. MEG is actively engaged in creating innovative solutions, including its eMSAGP, eMVAPEX and cogeneration technologies, to reduce GHG emissions and is committed to best practices in the areas of health, safety and the environment. MEG is also committed to developing strong relationships with Indigenous and local communities and to building an ethical, respectful, diverse and inclusive workplace.

MEG's 2020 strategic environmental, social and governance ("ESG") initiatives include:

- establish 2030 and 2050 climate change goals and continue to advance technology solutions to achieve net zero emissions by 2050;
- develop a robust diversity and inclusion policy to ensure that all employees and contractors feel valued, engaged and respected in the workplace and that MEG continues to attract and retain top talent; and

- increase its business relationships with and employment of Indigenous peoples.

MEG published its first ESG report in 2019, which provides details on the Corporation's approach with respect to certain ESG related issues and highlights the activities undertaken by MEG to address the needs of the world, its shareholders and its employees. This report is available in the "Sustainability" section of the Corporation's website at www.megenergy.com.

7. 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:

	Year ended December 31		2019				2018			
	2019	**2018**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**64.18**	71.53	**62.50**	61.97	68.32	63.90	68.08	75.97	74.90	67.18
WTI (US$/bbl)	**57.03**	64.77	**56.96**	56.45	59.82	54.90	58.81	69.50	67.88	62.87
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.76)**	(26.31)	**(15.83)**	(12.24)	(10.67)	(12.29)	(39.43)	(22.25)	(19.27)	(24.28)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(14.95)**	(29.99)	**(18.44)**	(14.52)	(12.32)	(14.50)	(44.60)	(25.69)	(22.21)	(27.45)
AWB – Edmonton (US$/bbl)	**42.08**	34.78	**38.52**	41.93	47.50	40.40	14.21	43.81	45.67	35.42
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(1.77)**	(6.68)	**(5.25)**	(2.50)	1.64	(0.89)	(6.25)	(5.63)	(7.83)	(7.00)
AWB – U.S. Gulf Coast (US$/bbl)	**55.26**	58.09	**51.71**	53.95	61.46	54.01	52.56	63.87	60.05	55.87
Condensate prices										
Condensate at Edmonton (C$/bbl)	**70.19**	78.88	**70.01**	68.73	74.76	67.25	59.63	87.35	88.84	79.72
Condensate at Edmonton as % of WTI	**92.8%**	94.0%	**93.1%**	92.2%	93.4%	92.1%	76.7%	96.2%	101.4%	100.2%
Condensate at Mont Belvieu, Texas (US$/bbl)	**48.24**	59.85	**50.08**	44.34	50.22	48.31	51.21	64.53	64.40	59.27
Condensate at Mont Belvieu, Texas as % of WTI	**84.6%**	92.4%	**87.9%**	78.5%	84.0%	88.0%	87.1%	92.8%	94.9%	94.3%
Natural gas prices										
AECO (C$/mcf)	**1.92**	1.62	**2.70**	0.95	1.12	2.86	1.70	1.28	1.26	2.26
Electric power prices										
Alberta power pool (C$/MWh)	**55.28**	50.19	**47.07**	46.95	56.37	70.73	55.57	54.46	55.92	34.81
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.3269**	1.2962	**1.3201**	1.3207	1.3376	1.3293	1.3215	1.3070	1.2911	1.2651
C$ equivalent of 1 US$ – period end	**1.2965**	1.3646	**1.2965**	1.3244	1.3091	1.3360	1.3646	1.2924	1.3142	1.2901

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. As a result, the WTI:WCS differential narrowed for the year ended December 31, 2019 compared to 2018.

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 at 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. The cost of condensate sourced from Mont Belvieu, Texas includes transportation costs of approximately US$5.95 per barrel of condensate from Mont Belvieu to the Edmonton area for the year ended December 31, 2019.

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 increased during the year ended December 31, 2019 as a result of low gas storage inventories heading into the winter months.

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 increased during the year ended December 31, 2019 primarily as a result of increased demand in February 2019 when the province of Alberta experienced extremely cold winter weather.

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 December 31, 2019 the Canadian dollar had increased in value by approximately 5% against the U.S. dollar compared to its value as at December 31, 2018.

8. OTHER OPERATING RESULTS

Depletion and Depreciation

($millions)		2019		2018
Depletion and depreciation expense	**$**	**710**	$	452
Depletion and depreciation expense per barrel of production	**$**	**20.90**	$	14.12

The Corporation incurred a one-time accelerated depreciation expense of $237 million, or $6.98 per barrel for the year ended December 31, 2019. The Corporation's strategy has shifted away from production growth in the near term which led to an assessment of existing assets during the second quarter of 2019. Given the uncertainty of future benefits associated with specific non-core assets that do not contribute to the Corporation's development plan or cash flow, accelerated depreciation was recognized on equipment, materials and engineering costs associated with greenfield expansion projects at Christina Lake which will not be pursued in the foreseeable future and on a partial upgrading technology project. None of these non-core assets relate to the Corporation's current development plans. Excluding this non–recurring item, depreciation expense for the year ended December 31, 2019 increased $21 million primarily due to the 6% increase in production during the year.

Commodity Risk Management Gain (Loss)

The Corporation enters into financial commodity risk management contracts to increase the predictability of the Corporation's cash flow by managing commodity price volatility. The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes. All financial commodity 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 commodity risk management contracts are the result of contract settlements during the period. Unrealized gains or losses on financial commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.

($millions)		2019		2018
Realized:				
Crude oil contracts[1]	**$**	**(89)**	$	(127)
Condensate contracts[2]		**(24)**		(12)
Realized commodity risk management gain (loss)	**$**	**(113)**	$	(139)
Unrealized:				
Crude oil contracts[1]	**$**	**(170)**	$	194
Condensate contracts[2]		**1**		(33)
Unrealized commodity risk management gain (loss)	**$**	**(169)**	$	161
Commodity risk management gain (loss)	**$**	**(282)**	$	22

(1) Includes WTI fixed price contracts, WTI collars, 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.

For the year ended December 31, 2019, the Corporation recognized a $282 million net loss from commodity risk management due to narrowing WTI:WCS differentials, rising WTI prices and declining condensate prices relative to contracted prices. This compares with the $22 million net gain from commodity risk management for the year ended December 31, 2018, when unrealized gains from decreasing forward WTI prices were partially offset by realized losses from the settlement of crude oil contracts at WTI prices above contracted values.

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

($/bbl)		2019		2018
WTI fixed price contracts:				
Average fixed price	$	62.13	$	53.76
Average settlement price		57.12		64.77
Gain (loss) on WTI fixed price contracts	$	5.01	$	(11.01)
WTI:WCS fixed differential contracts:				
Average fixed differential	$	(21.69)	$	(15.16)
Average settlement differential		(12.76)		(26.31)
Gain (loss) on WTI:WCS fixed differential contracts	$	(8.93)	$	11.15
Condensate purchase contracts:				
Average fixed differential[1]	$	(5.19)	$	3.33
Average settlement differential		(8.81)		(4.91)
Gain (loss) on condensate purchase contracts	$	(3.62)	$	(8.24)

(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

($millions)		2019		2018
General and administrative expense	$	68	$	83
General and administrative expense per barrel of production	$	1.99	$	2.58

General and administrative expense decreased 18% for the year ended December 31, 2019 compared to the same period of 2018, primarily due to the reduction of staffing levels in February 2019 and rationalization of ongoing administrative costs.

Stock-based Compensation

($millions)		2019		2018
Cash-settled expense	$	7	$	26
Equity-settled expense		24		21
Stock-based compensation	$	31	$	47

The value of cash-settled share-based units decreased for the year ended December 31, 2019, compared to the same period of 2018, due to a decrease in the Corporation's share price and a reduction in the number of share-based units resulting from reduced staffing levels. The decrease in total stock-based compensation was partially offset by a one-time charge of $10 million related to the accelerated expense of units for retirement eligible employees which was recorded during the second quarter of 2019.

Foreign Exchange Gain (Loss), Net

($millions)	2019	2018
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ 180**	$ (346)
US$ denominated cash and cash equivalents	**(8)**	5
Unrealized net gain (loss) on foreign exchange	**172**	(341)
Realized gain (loss) on foreign exchange	**3**	(5)
Realized gain (loss) on foreign exchange derivatives	**—**	35
Foreign exchange gain (loss), net	**$ 175**	$ (311)

C$ equivalent of 1 US$		
Beginning of period	**1.3646**	1.2518
End of period	**1.2965**	1.3646

For the year ended December 31, 2019, the Canadian dollar strengthened relative to the U.S. dollar by 5%, resulting in an unrealized foreign exchange gain of $172 million. For the year ended December 31, 2018, the Canadian dollar weakened by 9%, resulting in an unrealized foreign exchange loss of $341 million.

In March 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of $1.52 billion and other consideration of $90 million. Upon entering into the sale agreement, the Corporation entered into forward currency contracts to manage the foreign exchange risk on the Canadian dollar denominated sale proceeds designated for U.S. dollar denominated long-term debt repayment. The Corporation settled these forward currency contracts on closing of the sale and realized a foreign exchange gain of $35 million.

Net Finance Expense

($millions)	2019	2018
Interest expense on long-term debt	**$ 267**	$ 287
Interest expense on lease liabilities	**26**	13
Interest income	**(5)**	(8)
Net interest expense	**288**	292
Debt extinguishment expense	**46**	—
Accretion on provisions	**7**	8
Unrealized loss (gain) on derivative financial liabilities	**(1)**	3
Realized loss (gain) on interest rate swaps	**—**	(17)
Net finance expense	**$ 340**	$ 286
Average effective interest rate	**6.6%**	6.4%

Net finance expense for the year ended December 31, 2019 increased, compared to the same period of 2018, primarily due to a $46 million debt extinguishment expense associated with debt repayment and refinancing activities.

Throughout the second half of 2019, the Corporation repurchased and extinguished $204 million (US$154 million) in aggregate principal amount of its 6.5% senior secured second lien notes due January 2025. Included in debt extinguishment expense is a $4 million premium paid on the repurchase of the senior secured second lien notes and related unamortized deferred debt issue costs of $3 million.

Subsequent to December 31, 2019 and consistent with the Corporation's strategic focus on maintaining long-term financial liquidity while pursuing ongoing debt repayment, the Corporation announced the refinancing and extension of the maturity profile of its debt portfolio. On January 31, 2020 the Corporation successfully closed a private offering of US$1.2 billion in aggregate principal amount of 7.125% senior unsecured notes due February 2027. The net proceeds of the offering, together with cash on hand, were used to:

- Fully redeem US$800 million of the 6.375% senior unsecured notes due January 2023 at a redemption price of 101.063%;
- Partially redeem 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, the Corporation redeemed 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, debt extinguishment expense included a cumulative debt redemption premium of $29 million and associated unamortized deferred debt issue costs of $10 million.

Income Tax

($millions)	**2019**	2018
Income tax expense (recovery)	**$ (29)**	$ (49)
Effective tax rate	**32%**	29%

As at December 31, 2019, the Corporation had approximately $7.2 billion of available Canadian tax pools and recognized a deferred income tax asset of $262 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

The effective tax rate of 32% for the year ended December 31, 2019 is higher than the Canadian statutory rate of 26.5% due to the tax effect of unrealized foreign exchange gains on the Corporation's debt. In addition, a one-time deferred income tax expense of $33 million related to the Alberta tax rate reduction during 2019 reduced the expected income tax recovery and increased the effective tax rate.

9. SUMMARY OF ANNUAL INFORMATION

($millions, except per share amounts)	**2019**	**2018**	**2017**
Revenue[(1)]	**$ 3,931**	$ 2,733	$ 2,475
Net earnings (loss)	**(62)**	(119)	166
Per share - basic	**(0.21)**	(0.40)	0.57
Per share - diluted	**(0.21)**	(0.40)	0.57
Total assets	**7,866**	8,410	9,363
Total non-current liabilities	**3,455**	4,058	4,874

(1) The total of petroleum revenue, including the sale of third-party products related to marketing asset optimization activity, net of royalties and other revenue as presented on the Consolidated Statement of Earnings and Comprehensive Income. Effective January 1, 2018, petroleum revenues are presented on a gross basis as they represent separate performance obligations. The comparative prior periods have been revised to reflect the new presentation.

Revenue

During 2019 revenue increased 44% from 2018 primarily as a result of increased revenue from the sale of purchased products related to marketing asset optimization activities, which totaled $907 million in 2019 compared to $208 million in 2018. In addition, the average blend sales price increased by 15%, driven by the significant narrowing of the WTI:WCS differential from 2018 to 2019.

During 2018 revenue increased 10% from 2017 primarily as a result of increased blend sales volumes combined with a slight increase in blend sales price. An increase in WTI was mostly offset by significant widening of the WTI:WCS differential from 2017 to 2018.

Net Earnings (Loss)

The Corporation recognized a net loss of $62 million in 2019 compared to a net loss of $119 million in 2018. The decrease is due to an unrealized foreign exchange gain and a higher cash operating netback partially offset by an unrealized loss on commodity risk management.

The net loss in 2018 compared to net earnings in 2017 is primarily attributable to the reduction in cash operating netback due to the significant widening of the WTI:WCS differential plus the net foreign exchange loss in 2018 compared to a net foreign exchange gain in 2017. These factors were partially offset by a gain on asset dispositions relating to the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal.

Total Assets

Total assets at December 31, 2019 decreased compared to December 31, 2018, mainly as a result of depletion and depreciation charges that were in excess of capital expenditures. Also, with the corporate strategy shifting away from production growth in the near term, accelerated depreciation was recognized during the year related to the uncertainty of future benefits associated with specific non-core assets which no longer align with the Corporation’s future development plan.

Total assets as at December 31, 2018 decreased compared to December 31, 2017 primarily due to the asset dispositions relating to the sale of the Corporation's 50% interest in Access Pipeline and 100% interest in the Stonefell Terminal.

For a detailed discussion of the Corporation’s investing activities, see "LIQUIDITY AND CAPITAL RESOURCES – Cash Flow – Investing Activities".

Total Non-Current Liabilities

Total non-current liabilities as at December 31, 2019 decreased compared to December 31, 2018 primarily due to the repayment of long-term debt. During 2019, the Corporation fully repaid the outstanding senior secured term loan balance and repurchased and extinguished a portion of its 6.5% senior secured second lien notes.

Total non-current liabilities as at December 31, 2018 decreased compared to December 31, 2017 primarily due to the repayment of approximately $1.2 billion of the Corporation's senior secured term loan in 2018 from a portion of the proceeds from the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. This was partially offset by a $346 million unrealized foreign exchange loss on the translation of the U.S. dollar denominated debt as a result of the weakening Canadian dollar compared to the U.S. dollar by approximately 9% during the year.

10. LIQUIDITY AND CAPITAL RESOURCES

As at December 31 *($millions)*	2019	2018
First Lien:		
Senior secured term loan (December 31, 2019 – nil; December 31, 2018 – US$225 million)	**$ —**	$ 307
Second Lien:		
6.5% senior secured second lien notes (December 31, 2019 - US$596 million; December 31, 2018 - US$750 million; due 2025)	**773**	1,023
Unsecured:		
6.375% senior unsecured notes (US$800 million; due 2023)	**1,037**	1,092
7.0% senior unsecured notes (US$1 billion; due 2024)	**1,297**	1,365
Less:		
Debt redemption premium	**29**	—
Unamortized deferred debt discount and debt issue costs	**(13)**	(29)
Unamortized financial derivative liability discount	**—**	(1)
Long-term debt	**3,123**	3,757
Cash and cash equivalents	**(206)**	(318)
Net debt(1)	**$ 2,917**	$ 3,439

(1) *Net debt is reconciled to long-term debt in accordance with IFRS in Note 26 of the audited consolidated financial statements.*

During the year ended December 31, 2019 net debt decreased by $522 million. The Corporation fully repaid the outstanding senior secured term loan balance of $297 million (US$225 million) and repurchased and extinguished a portion of its 6.5% senior secured second lien notes totaling $204 million (US$154 million).

The Corporation's cash and cash equivalents balance was $206 million as at December 31, 2019 compared to $318 million as at December 31, 2018. Adjusted funds flow of $726 million during the year ended December 31, 2019 was more than offset by the repayment of debt, capital expenditures, and the significant decrease in non-cash working capital during the first quarter of 2019 relating to the settlement of December 2018 revenues when benchmark crude oil prices were significantly lower. Refer to the "Cash Flow Summary" section for further details.

On July 30, 2019, concurrent with the senior secured term loan repayment, the Corporation amended and restated its revolving credit facility and the EDC Facility and extended the maturity date of each facility by 2.75 years to July 30, 2024. The maturity dates of the revolving credit facility and the EDC Facility include a feature that will 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 Corporation has reduced the total available credit under the two facilities to $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 reduction of the total available credit is expected to reduce fees going forward by approximately $14 million annually.

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.

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

As at December 31, 2019, no amount had been drawn under the Corporation's $800 million revolving credit facility, and the Corporation had $99 million of unutilized capacity under the $500 million letter of credit facility.

Subsequent to December 31, 2019 and consistent with the Corporation's strategic focus on maintaining long-term financial liquidity while pursuing ongoing debt repayment, the Corporation successfully closed a private offering of US$1.2 billion in aggregate principal amount of 7.125% senior unsecured notes due February 2027. The net proceeds of the offering, together with cash on hand, were used to:

- Fully redeem US$800 million of the 6.375% senior unsecured notes due January 2023;
- Partially redeem US$400 million of the US$1.0 billion 7.00% senior unsecured notes due March 2024; and
- Pay fees and expenses related to the offering.

Concurrent with the private offering, the Corporation redeemed 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.

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.

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 December 31, 2019:

As at December 31, 2019	Volumes (bbls/d)[1]	Term	Average Price (US$/bbl)[1]
Crude Oil Sales Contracts			
WTI Fixed Price	34,475	Jan 1, 2020 - Dec 31, 2020	$58.75
WTI:WCS Fixed Differential	17,503	Jan 1, 2020 - Dec 31, 2020	$(22.06)
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	Jan 1, 2020 - Dec 31, 2020	$(7.63)
WTI:Mont Belvieu Fixed Differential	8,250	Jan 1, 2021 - Dec 31, 2021	$(10.38)
WTI:Mont Belvieu Fixed % of WTI	7,750	Jan 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 December 31, 2019:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$1.00 per bbl applied to WTI contracts	**$ (20)**	**$ 20**
Crude oil differential price[1]	± US$1.00 per bbl applied to WTI:WCS differential contracts	**$ 8**	**$ (8)**

(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 December 31, 2019:

As at December 31, 2019	Volumes[1]	Term	Average Price[1]
Crude Oil Sales Contracts	**(bbls/d)**		**(US$/bbl)**
WTI:AWB Fixed Differential	13,150	Jan 1, 2020 - Dec 31, 2020	(20.75)
Condensate Purchase Contracts	**(bbls/d)**		**(US$/bbl)**
WTI:Edmonton Fixed Differential	6,179	Jan 1, 2020 - Dec 31, 2020	(5.42)
Gas Purchases Contracts	**(Mcf/d)**		**(C$/Mcf)**
Fixed Price Gas Purchases	68,103	Jan 1, 2020 - Mar 31, 2020	2.48

(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 are provided for indicative purposes.*

The Corporation entered into the following financial commodity risk management contracts relating to crude oil sales and condensate purchases between December 31, 2019 and March 3, 2020:

Subsequent to December 31, 2019	Volumes (bbls/d)[(1)]	Term	Average Prices (US$/bbl)[(1)]
Crude Oil Sales Contracts			
WTI Fixed Price	9,834	Jan 1, 2020 - Oct 31, 2020	$61.01
WTI:WCS Fixed Differential	7,975	Apr 1, 2020 - Dec 31, 2020	$(15.71)
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	2,700	Jan 1, 2021 - Dec 31, 2021	$(10.34)
WTI:Mont Belvieu Fixed Differential	200	Jan 1, 2022 - Dec 31, 2022	$(11.30)

(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.*

Cash Flow Summary

($millions)	2019	2018
Net cash provided by (used in):		
Operating activities	**$ 631**	$ 280
Investing activities	**(211)**	851
Financing activities	**(523)**	(1,284)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(9)**	7
Change in cash and cash equivalents	**$ (112)**	$ (146)

Cash Flow – Operating Activities

The increase in net cash provided by operating activities for the year ended December 31, 2019 is primarily due to higher bitumen realizations. This was partially offset by a $220 million decrease in non-cash working capital during the first quarter of 2019 relating primarily to the settlement of December 2018 revenues when benchmark crude oil prices were significantly lower.

Cash Flow – Investing Activities

Net cash provided by investing activities in 2018 includes cash proceeds of $1.5 billion from the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal that closed in the first quarter of 2018. Excluding these proceeds, net cash used in investing activities decreased from $648 million in 2018 to $211 million in 2019, which reflects reduced capital spending activity in 2019.

Cash Flow – Financing Activities

Net cash used in financing activities for the year ended December 31, 2019 was $523 million compared to $1.3 billion for the same period of 2018. Net cash used in financing activities for the year ended December 31, 2019 consisted primarily of the repayment of the outstanding senior secured term loan balance of $297 million (US$225 million) and the repurchase and extinguishment of a portion of its 6.5% senior secured second lien notes totaling $204 million (US $154 million), all of which was funded by adjusted funds flow. Net cash used in financing activities for the year ended December 31, 2018 consisted of a $1.3 billion partial repayment of the Corporation's senior secured term loan from the majority of the net cash proceeds from the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal.

11. SHARES OUTSTANDING

As at December 31, 2019, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	Units
Common shares	**299.5**
Convertible securities	
Stock options[(1)]	**6.8**
Equity-settled RSUs and PSUs	**6.4**

(1) 5.3 million stock options were exercisable as at December 31, 2019.

As at March 3, 2020, the Corporation had 299.6 million common shares, 6.5 million stock options and 6.5 million equity-settled restricted share units and equity-settled performance share units outstanding, and 5.0 million stock options exercisable.

12. 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 December 31, 2019. 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)]	$ 371	$ 424	$ 421	$ 455	$ 441	$ 5,956	$ 8,068
Diluent purchases	274	21	21	17	—	—	333
Other operating commitments	15	11	10	10	10	42	98
Variable office lease costs	5	5	5	5	5	33	58
Capital commitments	4	—	—	—	—	—	4
Total Commitments	669	461	457	487	456	6,031	8,561
Other Obligations:							
Lease obligations	44	36	35	30	29	520	694
Long-term debt[(2)]	—	—	—	1,037	1,297	773	3,107
Interest on long-term debt[(2)]	207	207	207	147	73	4	845
Decommissioning obligation[(3)]	5	5	5	5	5	802	827
Total Commitments and Obligations	**$ 925**	**$ 709**	**$ 704**	**$ 1,706**	**$ 1,860**	**$ 8,130**	**$ 14,034**

(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 December 31, 2019.

(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 these claims. The Corporation believes that any liabilities that might arise from this matter are unlikely to have a material effect on its financial position.

13. 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.

14. 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 Note 3 and Note 4, respectively, of the annual consolidated financial statements for the year ended December 31, 2019.

15. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the year ended December 31, 2019 and December 31, 2018, other than compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($millions)		**2019**		2018
Share-based compensation	**$**	**14**	$	17
Salaries and short-term employee benefits		**9**		12
Termination benefits		**1**		4
	$	**24**	$	33

16. NEW ACCOUNTING STANDARDS

IFRS 16 *Leases*

The IASB issued IFRS 16, *Leases* ("IFRS 16"), which replaces IAS 17 *Leases*, and is effective for annual periods beginning on or after January 1, 2019. IFRS 16, a single recognition and measurement model applicable to lessees, requires recognition of lease assets and lease liabilities on the balance sheet. The standard eliminates the classification of leases as either operating leases or finance leases for lessees, essentially treating all leases as finance leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases. The accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases.

The Corporation adopted IFRS 16 *Leases,* effective January 1, 2019, using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period comparative financial information as the cumulative effect is recognized as an adjustment to the opening deficit on the transition date and the standard is applied prospectively. Therefore, the comparative information in the Corporation's condensed Consolidated balance sheet, Consolidated statement of earnings (loss) and comprehensive income, Consolidated statement of changes in shareholders' equity, and Consolidated statement of cash flow have not been restated.

On adoption of IFRS 16, the Corporation elected to use the following practical expedients permitted by the standard:

- Applied a single discount rate to a portfolio of leases with similar characteristics;
- Accounted for leases with a remaining term of less than 12 months as at January 1, 2019 as short-term leases;
- Used hindsight when determining the lease term where the contract contained options to extend or terminate the lease;
- Excluded initial direct costs from the measurement of the right-of-use ("ROU") asset as at January 1, 2019; and
- Relied on the Corporation's previous assessment of whether leases were onerous under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* immediately before initial application as an alternative to performing an impairment review on the ROU assets. ROU assets have been adjusted by the amount of the onerous contracts provision recognized in the consolidated financial statements as at December 31, 2018.

The impacts of the adoption of IFRS 16, as at January 1, 2019, are as follows:

($millions)		**IFRS 16 Opening Balance Sheet Adjustments**			
	Reported balance as at Dec 31, 2018	**Finance Sublease Receivables**[(a)]	**Transportation Leases**[(b)]	**Office Leases**[(b)]	**Restated balance as at January 1, 2019**
Assets					
Property, plant and equipment	$ 6,646		$ 17	$ 41	$ 6,704
Other assets	221	19			240
Deferred income tax asset	237	(5)		1	233
Liabilities					
Provisions and other liabilities	(294)		(17)	(44)	(355)
Shareholders' Equity					
Deficit	1,751	(14)		2	1,739
	$ 8,561	**$ —**	**$ —**	**$ —**	**$ 8,561**

a. On adoption, the Corporation has recognized finance sublease receivables in relation to certain sublease arrangements that were previously recognized on the consolidated balance sheet as at December 31, 2018 within the onerous contracts provision.

b. On adoption, the Corporation has recognized lease liabilities in relation to lease arrangements measured at the present value of the remaining lease payments as at December 31, 2018, and discounted using the Corporation's estimated incremental borrowing rate as of January 1, 2019. The associated ROU assets were measured at the amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, on January 1, 2019.

Significant Accounting Policies

Leases

The Corporation has applied IFRS 16 using the modified retrospective approach. As a result, the comparative information contained herein has been accounted for in accordance with the Corporation's previous accounting policies which can be found in the audited consolidated financial statements for the year ended December 31, 2018.

The following accounting policy is applicable as of January 1, 2019:

The Corporation assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration.

As Lessee

Leases are recognized as a lease liability and a corresponding ROU asset at the date on which the leased asset is available for use by the Corporation. Liabilities and assets arising from a lease are initially measured on a present value basis. Lease liabilities are measured at the present value of the remaining lease payments, discounted using the Corporation's estimated incremental borrowing rate when the rate implicit in the lease is not readily available. The corresponding ROU assets are measured at the amount equal to the lease liability.

The lease liability is remeasured when there is a change in the future lease payments arising from a change in an index or rate, if there is a change in the amount expected to be payable under a residual value guarantee or if there is a change in the assessment of whether the Corporation will exercise a purchase, extension or termination option that is within the control of the Corporation.

The ROU asset, initially measured at an amount equal to the corresponding lease liability, is depreciated on a straight-line basis, over the shorter of the estimated useful life of the asset or the lease term. The ROU asset may be adjusted for certain re-measurements of the lease liability and impairment losses.

Upon adoption of IFRS 16, the Corporation recognized an increase to depletion and depreciation expense on ROU assets, an increase to net finance expense on lease liabilities, a reduction to general and administrative expense and a reduction to transportation expense. Accounting treatment of existing sale and leasebacks resulting in a finance lease under IAS 17 remained unchanged.

Lease payments are allocated between the lease liability and finance costs. Cash outflows for repayment of the principal portion of the lease liability is classified as cash flows from financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

Leases that have terms of less than twelve months or leases on which the underlying asset is of low value are recognized as an expense in the consolidated statement of earnings (loss) on a straight-line basis over the lease term.

As Lessor

Accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, and disclosure requirements are enhanced. As an intermediate lessor, the Corporation accounts for its interest in head leases and subleases separately. Upon adoption of IFRS 16, the Corporation reassessed subleases previously classified as operating leases under IAS 17 to determine whether each sublease should be classified as an operating lease or a finance lease. Operating leases that were reclassified to finance leases were accounted for as a new finance lease entered into on January 1, 2019.

17. 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. The most significant risks faced by the Corporation are detailed below. Further information regarding the risk factors which may affect the Corporation is contained in the most recently filed Annual Information Form ("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.

If any event arises from the risk factors disclosed, the Corporation's business, prospects, financial condition, results or operations or cash flows and, in some cases, the Corporation's reputation could be materially adversely affected. The Corporation has an Enterprise Risk Management ("ERM") Program, which is a continuous process to manage, monitor, analyze and take action on risks that threaten the Corporation's ability to reach it's strategic objectives. The ERM program ensures the risks are appropriately categorized within a risk matrix, and risk mitigation strategies are employed when deemed necessary.

Risks arising from operations

MEG's operating results and the value of its reserves and contingent resources depend, in part, on the price received for bitumen and on the operating costs of the Christina Lake Project and MEG's other projects, all of which may significantly vary from that currently anticipated. If such operating costs increase or MEG does not achieve its expected revenues, MEG's earnings and cash flow will be reduced and its business and financial condition may be materially adversely affected. Principal factors, amongst others, which could affect MEG's operating results include (without limitation):

- a decline in oil prices;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher SORs, or the inability to recognize continued or increased efficiencies from the Corporation’s production enhancement program which uses a combination of proprietary reservoir technologies (including eMSAGP and eMVAPEX) and processing plant enhancements, debottlenecking and brownfield expansions;
- reduced access to or an increase in the cost of diluent;
- an increase in the cost of natural gas;
- the reliability and maintenance of MEG's facilities;
- the safety and reliability of the Access Pipeline, other pipelines, tankage, railways and railcars and barges to transport MEG's products;
- the need to replace significant portions of existing wells, referred to as "workovers", or the need to drill additional wells;
- the cost to transport bitumen, diluent and bitumen blend, and the cost to dispose of certain by-products;
- the availability and cost of insurance and the inability to insure against certain types of losses;
- severe weather or catastrophic events such as fires, lightning, earthquakes, extreme cold weather, storms or explosions;
- seasonal weather patterns and the corresponding effects of the spring thaw on accessibility to MEG's properties;
- the availability of water supplies and the ability to transmit power on the electrical transmission grid;
- changes in the political landscape and/or legal and regulatory regimes in Canada, the United States and elsewhere;
- the ability to obtain further approvals and permits for MEG's future projects;
- the availability of pipeline capacity and other transportation and storage facilities for MEG's bitumen blend;
- refining markets for MEG's bitumen blend;
- increased royalty payments resulting from changes in regulatory regimes;
- the cost of chemicals used in MEG's operations, including, but not limited to, in connection with water and/or oil treatment facilities;
- the availability of and access to drilling equipment; and
- the cost of compliance with applicable regulatory regimes, including, but not limited to, environmental regulation and Government of Alberta production curtailments.

Single Asset

All of MEG's current production and a significant amount of future production, is or will be generated by the Christina Lake Project and transported to markets on the Access Pipeline, Enbridge mainline and Flanagan South and Seaway Pipelines. Any event that interrupts operations at the Christina Lake Project or the operations of these pipelines may result in a significant loss or delay in production.

Cybersecurity

The Corporation's operations may be negatively impacted by a cybersecurity incident. MEG uses forms of information technology in its operations and such use creates various cybersecurity threats including the possibility of security breaches, operational disruptions and the release of non-public information (such as financial data, supplier and customer information and employee information). Although MEG has taken various steps to protect itself against such risks, its efforts may not always be successful, especially because of the rapidly changing nature of such cybersecurity threats. In the event of a cybersecurity incident, MEG's operations could be disrupted resulting in potential loss of customers, violation of laws and additional liabilities to the business.

Risks related to economic conditions

Fluctuations in market prices of Crude Oil, Bitumen Blend and Differentials

MEG's results of operations and financial condition will be dependent upon, among other things, the prices that it receives for the bitumen, bitumen blend or other bitumen products that it sells, and the prices that it receives for such products will be closely correlated to the price of crude oil. Historically, crude oil markets have been volatile and are likely to continue to be volatile in the future. Crude oil prices, and differentials between world crude oil prices and Canadian heavy crude oil prices, have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond MEG's control. These factors include, but are not limited to:

- global energy policy, including (without limitation) the ability of the Organization of the Petroleum Exporting Countries to set and maintain production levels and influence prices for crude oil;
- political instability and hostilities;
- domestic and foreign supplies of crude oil;
- the overall level of energy demand;
- weather conditions;
- government regulations including curtailment orders;
- taxes;
- currency exchange rates;
- the availability of refining capacity and transportation infrastructure;
- International Maritime Organization ("IMO") 2020 guidelines on reduced sulphur in marine fuels
- the effect of worldwide environmental and/or energy conservation measures;
- the price and availability of alternative energy supplies; and
- the overall economic environment.

Any prolonged period of low crude oil prices, or a widening of differentials, could result in a decision by MEG to suspend or slow development activities, to suspend or slow the construction or expansion of bitumen recovery projects or to suspend or reduce production levels. Any of such actions could have a material adverse effect on MEG's results of operations, financial condition and prospects.

The market prices for heavy oil (which includes bitumen blends) are lower than the established market prices for light and medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy oil. Also, the market for heavy oil is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fluctuations. These factors all contribute to price differentials. Future price differentials are uncertain and any widening in heavy oil differentials specifically could have an adverse effect on MEG's results of operations, financial condition and prospects.

MEG conducts an assessment of the carrying value of its assets to the extent required by IFRS. If crude oil prices decline, the carrying value of MEG's assets could be subject to downward revision, and MEG's earnings could be adversely affected by any reduction in such carrying value.

Volatility of Commodity Inputs

The nature of the Corporation's operations results in exposure to fluctuations in bitumen, diluent and gas prices. Natural gas is a significant component of the Corporation's cost structure, as it is used to generate steam for the SAGD process and to create electricity at the Corporation's cogeneration facility. Diluent, such as condensate, is also one of the Corporation's significant commodity inputs and is used as part of MEG's product marketing strategy and to decrease the viscosity of the bitumen in order to allow it to be transported.

Historically, crude oil and electricity prices have been positively correlated with the prices of natural gas and condensate, respectively. As a result, the Corporation expects to be able to offset a portion or all of the increase in its costs associated with an increase in the price of natural gas or condensate with an increase in revenue that results from higher oil prices and electricity sold by the Corporation's cogeneration units. The Corporation believes this correlation has been caused by factors that are not within its control, and investors are cautioned not to rely on this correlation continuing. If the prices of these commodities cease to be positively correlated, and the price of crude oil or electricity falls while the prices of natural gas or diluent rise or remain steady, the Corporation's results of operations, financial condition and prospects could be adversely affected.

Variations in Foreign Exchange Rates and Interest Rates

Most of MEG's revenues are based on the U.S. dollar, since revenue received from the sale of bitumen and bitumen blends is generally referenced to a price denominated in U.S. dollars, and MEG incurs most of its operating and other costs in Canadian dollars. As a result, MEG is impacted by exchange rate fluctuations between the U.S. dollar and the Canadian dollar, and any strengthening of the Canadian dollar relative to the U.S. dollar could negatively impact MEG's operating margins and cash flows. In addition, as MEG reports its operating results in Canadian dollars, fluctuations in product pricing and in the rate of exchange between the U.S. dollar and Canadian dollar affect MEG's reported results.

Further, substantially all of the Corporation's debt is denominated in U.S. dollars. Fluctuations in exchange rates may significantly increase or decrease the amount of debt recorded in the Corporation's financial statements, which could have a significant effect on the Corporation's results of operations, financial condition and prospects.

Hedging Strategies

The Corporation uses physical and financial instruments to hedge its exposure to fluctuations in commodity prices, exchange rates and interest rates. Engagement by the Corporation in such hedging activities will expose it to credit related losses in the event of non-performance by counterparties to the physical or financial instruments. Additionally, if bitumen, diluent or gas prices, interest rates or exchange rates increase above or decrease below those levels specified in any hedging agreements, such hedging arrangements may prevent the Corporation from realizing the full benefit of such increases or decreases. In addition, any future commodity hedging arrangements could cause the Corporation to suffer financial loss, if it is unable to produce sufficient quantities of the commodity to fulfill its obligations, if it is required to pay a margin call on a hedge contract or if it is required to pay royalties based on a market or reference price that is higher than the Corporation's fixed ceiling price.

To the extent that risk management activities and hedging strategies are employed to address commodity prices, exchange rates, interest rates or other risks, risks associated with such activities and strategies, including (without limitation) counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate such activities and strategies, which would have a negative impact on MEG's results of operations, financial position and prospects.

Global Financial Markets

The market events and conditions that transpired since 2008, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have, among other things, caused significant volatility in commodity prices. These events and conditions caused a loss of confidence in the broader U.S., European Union and global credit and financial markets and resulted in the collapse of, and government intervention in, numerous major banks, financial institutions and insurers, and created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors negatively impacted enterprise valuations and impacted the performance of the global economy.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties regarding the supply and demand fundamentals for petroleum products due to the current state of the world's economies, actions taken by the Organization of the Petroleum Exporting Countries, and the ongoing risks facing the North American and global economies and new supplies of crude oil which may be created by the application of new drilling technology to unconventional resource plays. It is possible that petroleum prices could move lower, or could remain near current price levels for a considerable period of time.

Climate change, environmental and regulatory risks

Climate Change Physical and Transitional Consequences

Climate change may introduce new risks to the Corporations business including both physical risks and transitional risks. Physical risks associated with climate change may include severe changes to weather patterns or catastrophic events such as fires, lightning, earthquakes, extreme cold weather, storms or explosions, changes to seasonal weather patterns and the corresponding effects of seasonal conditions and temperatures, any of which may impact the Corporation's operations.

Transitional risks include a broader set of risks associated with a global transition to a less carbon-intensive economy, including changes to laws and regulations discussed under the heading *Environmental Considerations* below, increased activism and public opposition to fossil fuels and oil sands and reputational risks. Reputational risks include numerous factors which could negatively affect the Corporation's reputation, including general public perceptions of the energy industry, negative publicity relating to pipeline incidents, unpopular expansion plans or new projects, opposition from organizations and populations opposed to fossil fuels development, specifically oil sands projects and pipeline projects, including expansions thereof. A negative impact from transitional risks could result in loss of customers, revenue loss, delays in obtaining regulatory approvals for pipelines and other projects, increased operating, capital, financing or regulatory costs, diminished shareholder confidence, continuing changes to laws and regulations affecting the Corporation's business or erosion or loss of public support towards the hydrocarbon-based energy sector.

Public Perception of Alberta Oil Sands

Development of the Alberta oil sands has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous engagement. The influence of anti-fossil fuels activists (with a focus on oil sands) targeting equity and debt investors, lenders and insurers may result in policies which reduce support for or investment in the Alberta oil sands sector. Concerns about oil sands may, directly or indirectly, impair the profitability of our current oil sands projects, and the viability of future oil sands projects, by creating significant regulatory uncertainty leading to uncertainty in economic modeling of current and future projects and delays relating to the sanctioning of future projects. In addition, evolving decarbonization policies of institutional investors, lenders and insurers could affect the Corporation's ability to access capital pools. Certain insurance companies have taken actions or announced policies to limit available coverage for companies which derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of the Corporation's insurance policies could increase substantially. In some instances, coverage may become unavailable or available only for reduced amounts of coverage. As a result, the Corporation may not be able to extend or renew existing policies, or procure other desirable insurance coverage, either on commercially reasonable terms, or at all. Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, changes in environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, potentially increasing the cost of construction, operation and abandonment. In addition, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil, reduce its price and may result in stranded assets or an inability to further develop oil resources.

Climate-Related Goals

The Corporation’s long-term ambition of reaching net-zero emissions (which is inherently uncertain due to the potentially long time frame and certain factors outside of the Corporation’s control, including the application of future technologies) is subject to numerous risks and uncertainties. The Corporation’s actions taken in implementing such a target may expose the Corporation to certain additional and/or heightened financial and operational risks.

All of the Corporation’s climate-related goals, including those related to GHG emissions, and others associated with diversity, relationships with stakeholders, including Indigenous stakeholders and wildlife habitat reclamation depend significantly on the Corporation’s ability to execute its current business strategy, which can be impacted by the numerous risks and uncertainties associated with the Corporation’s business and other industry factors. There is a risk that some or all of the expected benefits and opportunities of achieving some or all of the Corporation’s climate-related goals may fail to materialize, may cost more to achieve or may not occur within anticipated or stated time frames. In addition, there are risks that the actions taken by the Corporation in implementing these goals, and in making efforts to achieve such goals, may have a negative impact on the Corporation’s business, including adverse impacts on operations or increased costs and capital expenditures, which may in turn negatively impact our future operating and financial results.

Environmental considerations

The operations of the Corporation are, and will continue to be, affected in varying degrees by federal and provincial laws and regulations regarding the protection of the environment. Should there be changes to existing laws or regulations, the Corporation's competitive position within the thermal oil industry may be adversely affected, and many industry participants have greater resources than the Corporation to adapt to legislative changes.

No assurance can be given that future environmental approvals, laws or regulations will not adversely impact the Corporation's ability to develop and operate its oil sands projects, increase or maintain production or control its costs of production. Equipment which can meet future environmental standards may not be available on an economic or timely basis and instituting measures to ensure environmental compliance in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass future legislation that may progressively increase tax on air emissions (specifically greenhouse gas) or require, directly or indirectly, reductions in air emissions produced by energy industry participants, which the Corporation may be unable to mitigate.

All phases of the oil business present environmental risks and hazards and are subject to environmental legislation and regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, permit requirements, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil sands operations and restrictions on water usage and land disruption. The legislation also requires that wells and facility sites be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs, and both the federal government and the Government of Alberta have indicated an intent to impose more stringent environmental legislation that will affect the oil sands industry. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. No assurance can be given that environmental laws and regulations will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's results of operations, financial condition and prospects.

The Corporation believes that it is reasonably likely that the trend towards stricter standards in environmental legislation will continue and anticipates that capital and operating costs may increase as a result of more stringent environmental laws. Even in the absence of a change to law or regulations, public pressure and a decrease in investor confidence may result in delays to infrastructure, lowered access to capital and insurance and less access to services.

Greenhouse Gas Regulations

The direct and indirect costs of the various GHG regulations, existing and proposed in both Canada and the United States (including any limit on oil sands emissions) and the federal government's implementation of the Paris Agreement through the *Greenhouse Gas Pollution Pricing Act* and the Alberta government's implementation of the *Technology Innovation and Emissions Reduction Regulation*, may adversely affect MEG's business, operations and financial results. Equipment that meets future GHG emission standards may not be available on an economic basis and other compliance methods to reduce emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economical basis. Any failure to meet GHG emission reduction compliance obligations may have a material adverse effect on the Corporation's business and result in fines, penalties and the suspension of operations.

Future federal legislation, including the implementation of potential international requirements enacted under Canadian law, as well as provincial legislation and emissions reduction requirements, may require the reduction of GHG or other industrial air emissions, or emissions intensity, from the Corporation's operations and facilities. Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and natural gas producers. The Corporation is unable to predict the impact of emissions reduction legislation on the Corporation and it is possible that such legislation may have a material adverse effect on MEG's financial condition, results of operations and prospects.

Risks related to financing and the Corporation's indebtedness

Upon the occurrence of any event of default under the Credit Facility and the EDC Guaranteed L/C Facility, MEG's lenders and other secured parties could elect to declare all amounts outstanding thereunder, together with accrued interest, to be immediately due and payable and to terminate any commitments to extend further credit. If the lenders and other secured parties under the Credit Facility and the EDC Guaranteed L/C Facility accelerate the payment of the indebtedness outstanding thereunder, MEG's assets may not be sufficient to repay in full that indebtedness and MEG's other indebtedness, including the Second Lien Notes.

The restrictions in the Credit Facility, the EDC Guaranteed L/C Facility and the indentures governing the Notes may adversely affect MEG's ability to finance its future operations and capital needs and to pursue available business opportunities. Moreover, any new indebtedness MEG incurs may impose financial restrictions and other covenants on MEG that may be more restrictive than the Credit Facility, the EDC Guaranteed L/C Facility and the indentures governing the Notes.

The Corporation's indebtedness could materially and adversely affect it in a number of ways. For example, it could:

- require the Corporation to dedicate a portion of its cash flow to service payments on its indebtedness, thereby reducing the availability of cash flow to fund working capital, capital expenditures, development efforts and other general corporate purposes;
- increase the Corporation's vulnerability to general adverse economic and industry conditions;
- limit the Corporation's flexibility in planning for, or reacting to, changes in its business and the industry in which it operates;
- place the Corporation at a competitive disadvantage compared to its competitors that have less debt;
- expose the Corporation to the risk of increased interest rates as the Credit Facility and the EDC Guaranteed L/C Facility are at variable rates of interest; and
- limit the Corporation's ability to borrow additional funds to meet its operating expenses and for other purposes.

The Corporation may not generate sufficient cash flow and may not have available to it future borrowings in an amount sufficient to enable it to make payments with respect to its indebtedness or to fund its other capital needs. In these circumstances, the Corporation may need to refinance all or a portion of its indebtedness on or before maturity. Without such financing, the Corporation could be forced to sell assets or secure additional financing to make up for any shortfall in its payment obligations under unfavorable circumstances. However, the Corporation may not be able to raise additional capital or secure additional financing on terms favourable to it or at all, and the terms of the Credit Facility, the EDC Guaranteed L/C Facility, certain other permitted obligations and the indentures governing the Notes may limit its ability to sell assets and also restrict the use of proceeds from such a sale.

18. 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. The CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the Corporation and have concluded that the Corporation's disclosure controls and procedures were effective at December 31, 2019 for the foregoing purposes.

19. 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’s and CFO’s evaluation concluded that internal controls over financial reporting were effective as of December 31, 2019.

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.

20. 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

21. ADVISORY

Forward-Looking Information

This document may contain forward-looking information 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.

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 include, but are not limited to: risks associated with the oil and gas industry, for example, securing access to markets and transportation infrastructure and the commitments and risks therein; the unavailability of, or outages to third-party infrastructure that could cause disruptions to production or prevent the Corporation from being able to transport its products; the occurrence of a protracted operational outage caused by operational failures or catastrophic environmental events such as fires (including forest fires), equipment failures and other similar events affecting the Corporation or other parties whose operations or assets directly or indirectly affect the Corporation; extent and timelines of the Alberta Government's mandatory production curtailment program; availability of capacity on the electricity transmission grid; uncertainty of reserve and resource estimates; uncertainty associated with estimates and projections relating to production, costs and revenues;

health, safety and environmental risks; 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; risks relating risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the Corporation's future phases and the expansion and/or operation of the Corporation's projects; risks and uncertainties related to the timing of completion, commissioning, and start-up, of the Corporation's future phases, expansions and projects; the operational risks and delays in the development, exploration, production, and the capacities and performance associated with the Corporation's projects; 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 which is available 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.

22. 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.

23. QUARTERLY SUMMARIES

	2019				2018[1]			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**26**	24	(64)	(48)	(199)	118	(179)	141
Per share, diluted	**0.09**	0.08	(0.21)	(0.16)	(0.67)	0.39	(0.61)	0.47
Adjusted funds flow	**157**	192	227	151	(37)	116	18	83
Per share, diluted	**0.51**	0.63	0.76	0.50	(0.13)	0.39	0.06	0.28
Capital expenditures	**72**	40	33	53	144	139	191	148
Cash and cash equivalents	**206**	154	399	154	318	373	564	675
Working capital	**123**	204	416	175	290	274	211	446
Long-term debt	**3,123**	3,257	3,582	3,660	3,740	3,544	3,607	3,543
Shareholders' equity	**3,853**	3,828	3,795	3,851	3,886	4,068	3,946	4,113
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**56.96**	56.45	59.82	54.90	58.81	69.50	67.88	62.87
Differential – WTI:WCS – Edmonton (US$/bbl)	**(15.83)**	(12.24)	(10.67)	(12.29)	(39.43)	(22.25)	(19.27)	(24.28)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(18.44)**	(14.52)	(12.32)	(14.50)	(44.60)	(25.69)	(22.21)	(27.45)
AWB – Edmonton (US$/bbl)	**38.52**	41.93	47.50	40.40	14.21	43.81	45.67	35.42
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(5.25)**	(2.50)	1.64	(0.89)	(6.25)	(5.63)	(7.83)	(7.00)
AWB – U.S. Gulf Coast (US$/bbl)	**51.71**	53.95	61.46	54.01	52.56	63.87	60.05	55.87
C$ equivalent of 1US$ – average	**1.3201**	1.3207	1.3376	1.3293	1.3215	1.3070	1.2911	1.2651
Natural gas – AECO ($/mcf)	**2.70**	0.95	1.12	2.86	1.70	1.28	1.26	2.26
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**134,932**	132,455	137,120	132,377	126,750	130,823	108,237	135,701
Diluent usage – bbls/d	**(40,585)**	(37,463)	(42,000)	(42,555)	(38,467)	(36,967)	(33,819)	(44,093)
Bitumen sales – bbls/d	**94,347**	94,992	95,120	89,822	88,283	93,856	74,418	91,608
Bitumen production – bbls/d	**94,566**	93,278	97,288	87,113	87,582	98,751	71,325	93,207
Steam-oil ratio (SOR)	**2.27**	2.26	2.16	2.20	2.22	2.17	2.22	2.17
Blend sales	**56.55**	60.26	69.19	59.02	37.76	63.68	62.41	51.20
Cost of diluent	**(9.69)**	(6.89)	(6.96)	(8.81)	(22.45)	(14.05)	(15.08)	(15.74)
Bitumen realization	**46.86**	53.37	62.23	50.21	15.31	49.63	47.33	35.46
Transportation and storage – net	**(10.75)**	(10.57)	(10.80)	(11.27)	(10.28)	(9.11)	(8.28)	(5.99)
Third-party curtailment credits	**(0.21)**	(0.37)	(0.89)	—	—	—	—	—
Royalties	**(1.18)**	(1.54)	(2.06)	(0.37)	(0.15)	(2.01)	(1.64)	(1.03)
Operating costs – non-energy	**(4.49)**	(4.22)	(4.53)	(5.22)	(4.25)	(4.38)	(5.47)	(4.55)
Operating costs – energy	**(2.95)**	(1.51)	(1.78)	(3.36)	(1.98)	(1.50)	(1.79)	(2.64)
Power revenue	**1.57**	1.43	1.65	2.41	1.68	1.54	1.62	1.21
Realized gain (loss) on commodity risk management	**(0.52)**	(4.15)	(5.94)	(2.60)	6.81	(10.16)	(13.11)	(2.15)
Cash operating netback	**28.33**	32.44	37.88	29.80	7.14	24.01	18.66	20.31
Power sales price (C$/MWh)	**49.61**	50.30	55.33	70.83	55.38	51.53	51.02	35.50
Power sales (MW/h)	**124**	112	118	128	111	117	98	130
Average cost of diluent ($/bbl of diluent)	**79.07**	77.71	84.95	77.61	89.28	99.37	95.60	83.91
Average cost of diluent as a % of WTI	**105%**	104%	106%	106%	115%	109%	109%	105%
Depletion and depreciation rate per bbl of production	**13.18**	13.43	41.22	14.68	13.79	13.85	16.08	13.22
General and administrative expense per bbl of production	**2.25**	1.66	1.81	2.27	2.54	2.35	2.95	2.59
COMMON SHARES								
Shares outstanding, end of period (000)	**299,508**	299,288	299,207	296,857	296,841	296,813	296,751	294,105
Common share price ($) - close (end of period)	**7.39**	5.80	5.02	5.10	7.71	8.03	10.96	4.55

(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 $54.90/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;
- 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 the decision to discontinue exploration and evaluation activities in the Duncan area 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;
- planned turnaround and other maintenance activities affecting production; and
- a first quarter 2018 gain on asset disposition related to the Corporation's sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal.

24. 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%**	109%	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.*

REPORT OF MANAGEMENT

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

The accompanying consolidated financial statements of MEG Energy Corp. (the "Corporation") are the responsibility of Management. The consolidated financial statements have been presented and prepared within acceptable limits of materiality by Management in Canadian dollars in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and include certain estimates that reflect Management's best judgments.

The Corporation maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Corporation's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that the Corporation's internal controls over financial reporting were effective as of December 31, 2019.

The Corporation's Board of Directors has approved the consolidated financial statements. The Board of Directors fulfills its responsibility regarding the consolidated financial statements mainly through its Audit Committee, which is made up of four independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation. The Audit Committee meets with Management and the independent auditors at least on a quarterly basis to review and approve interim consolidated financial statements and management's discussion and analysis prior to their release as well as annually to review the annual consolidated financial statements and management's discussion and analysis and recommend their approval to the Board of Directors.

PricewaterhouseCoopers LLP, an independent firm of auditors, has been engaged, as approved by a vote of the shareholders at the Corporation's most recent Annual General Meeting, to audit and provide their independent audit opinion on the Corporation's consolidated financial statements as at and for the year ended December 31, 2019. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

/s/ Derek Evans	/s/ Eric L. Toews
Derek Evans	Eric L. Toews, CPA, CA
President and Chief Executive Officer	Chief Financial Officer

March 4, 2020

Independent auditor's report

To the Shareholders of MEG Energy Corp.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of MEG Energy Corp. and its subsidiary (together, the Corporation) as at December 31, 2019 and 2018, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited

The Corporation's consolidated financial statements comprise:

- the consolidated balance sheets as at December 31, 2019 and 2018;
- the consolidated statements of earnings (loss) and comprehensive income (loss) for the years then ended;
- the consolidated statements of changes in shareholders' equity for the years then ended;
- the consolidated statements of cash flow for the years then ended; and
- the notes to the consolidated financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

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Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Corporation's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Corporation to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this independent auditor's report is Jason Grodziski.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants

Calgary, Alberta
March 4, 2020

Consolidated Balance Sheet
(Expressed in millions of Canadian dollars)

As at December 31	Note		2019		2018
Assets					
Current assets					
Cash and cash equivalents	22	**$**	**206**	$	318
Trade receivables and other	5		**382**		218
Inventories	6		**93**		97
Commodity risk management	24		**—**		123
			681		756
Non-current assets					
Property, plant and equipment	3, 7		**6,206**		6,646
Exploration and evaluation assets	8		**490**		550
Other assets	3, 9		**227**		221
Deferred income tax asset	3, 12		**262**		237
Total assets		**$**	**7,866**	$	8,410
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities		**$**	**379**	$	343
Interest payable			**74**		84
Current portion of long-term debt	10		**—**		17
Current portion of provisions and other liabilities	11		**28**		17
Commodity risk management	24		**77**		6
			558		467
Non-current liabilities					
Long-term debt	10		**3,123**		3,740
Provisions and other liabilities	3, 11		**332**		294
Commodity risk management	24		**—**		24
Total liabilities			**4,013**		4,525
Shareholders' equity					
Share capital	13		**5,443**		5,427
Contributed surplus			**182**		170
Deficit	3		**(1,801)**		(1,751)
Accumulated other comprehensive income			**29**		39
Total shareholders' equity			**3,853**		3,885
Total liabilities and shareholders' equity		**$**	**7,866**	$	8,410

Commitments and contingencies (Note 27)

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

These Consolidated Financial Statements were approved by the Corporation's Board of Directors on March 4, 2020.

/s/ Derek Evans　　　　*/s/* Robert B. Hodgins

Derek Evans, Director　　　　Robert B. Hodgins, Director

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

Year ended December 31	Note		2019		2018
Revenues					
Petroleum revenue, net of royalties	15	**$**	**3,858**	$	2,673
Other revenue	15		**73**		60
Total revenues			**3,931**		2,733
Expenses					
Diluent and transportation	16		**1,568**		1,561
Operating expenses			**238**		210
Purchased product			**900**		264
Third-party curtailment credits			**13**		—
Depletion and depreciation	7, 9		**710**		452
Exploration expense	8		**58**		1
General and administrative			**68**		83
Stock-based compensation	14		**31**		47
Net finance expense	18		**340**		286
Other expenses	19		**23**		33
Other income	20		**(20)**		—
Gain on asset dispositions	8, 9		**(14)**		(325)
Commodity risk management loss (gain), net	24		**282**		(22)
Foreign exchange (gain) loss, net	17		**(175)**		311
Loss before income taxes			**(91)**		(168)
Income tax expense (recovery)	12		**(29)**		(49)
Net loss			**(62)**		(119)
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment			**(10)**		16
Comprehensive loss		**$**	**(72)**	$	(103)
Net loss per common share					
Basic	23	**$**	**(0.21)**	$	(0.40)
Diluted	23	**$**	**(0.21)**	$	(0.40)

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

Consolidated Statement of Changes in Shareholders' Equity
(Expressed in millions of Canadian dollars)

	Note	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2018		**$ 5,427**	**$ 170**	**$ (1,751)**	**$ 39**	**$ 3,885**
IFRS 16 opening deficit adjustment	3	**—**	**—**	**12**	**—**	**12**
Stock-based compensation		**—**	**26**	**—**	**—**	**26**
Stock options exercised		**2**	**—**	**—**	**—**	**2**
RSUs vested and released		**14**	**(14)**	**—**	**—**	**—**
Comprehensive income (loss)		**—**	**—**	**(62)**	**(10)**	**(72)**
Balance as at December 31, 2019		**$ 5,443**	**$ 182**	**$ (1,801)**	**$ 29**	**$ 3,853**

Balance as at December 31, 2017	$ 5,404	$ 167	$ (1,629)	$ 23	$ 3,965
IFRS 9 opening deficit adjustment	—	—	(5)	—	(5)
Stock-based compensation	—	25	—	—	25
Stock options exercised	2	(1)	—	—	1
RSUs vested and released	21	(21)	2	—	2
Comprehensive income (loss)	—	—	(119)	16	(103)
Balance as at December 31, 2018	$ 5,427	$ 170	$ (1,751)	$ 39	$ 3,885

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

Consolidated Statement of Cash Flow
(Expressed in millions of Canadian dollars)

Year ended December 31	Note	2019	2018
Cash provided by (used in):			
Operating activities			
Net loss		**$ (62)**	$ (119)
Adjustments for:			
Deferred income tax expense (recovery)	12	**(29)**	(50)
Depletion and depreciation	7, 9	**710**	452
Exploration expense	8	**58**	1
Stock-based compensation	14	**24**	21
Unrealized net (gain) loss on foreign exchange	17	**(172)**	341
Unrealized loss (gain) on commodity risk management	24	**169**	(161)
Amortization of debt discount and debt issue costs	10	**15**	15
Gain on asset dispositions	8, 9	**(14)**	(325)
Debt extinguishment expense	18	**46**	—
Other		**6**	12
Decommissioning expenditures	11	**(2)**	(5)
Payments on onerous contracts	11	**—**	(19)
Net change in other liabilities		**(8)**	5
Funds flow from operating activities		**741**	169
Net change in non-cash working capital items	22	**(110)**	111
Net cash provided by (used in) operating activities		**631**	280
Investing activities			
Capital expenditures:			
Property, plant and equipment	7	**(197)**	(622)
Exploration and evaluation	8	**(1)**	(1)
Net proceeds on dispositions	8, 9	**18**	1,509
Other		**(1)**	(9)
Net change in non-cash working capital items	22	**(30)**	(26)
Net cash provided by (used in) investing activities		**(211)**	851
Financing activities			
Issue of shares, net of issue costs		**1**	1
Repayment of long-term debt	22	**(297)**	(1,285)
Repurchase of senior secured second lien notes	22	**(204)**	—
Premium paid on repurchase of senior secured second lien notes	18	**(4)**	—
Refinancing costs		**(1)**	—
Payments on leased liabilities	11	**(19)**	—
Receipts on leased assets	22	**1**	—
Net cash provided by (used in) financing activities		**(523)**	(1,284)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(9)**	7
Change in cash and cash equivalents		**(112)**	(146)
Cash and cash equivalents, beginning of period		**318**	464
Cash and cash equivalents, end of period		**$ 206**	$ 318

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

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

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board. The consolidated financial statements have been prepared on the historical cost basis, except as detailed in the significant accounting policies disclosed in Note 3. Certain prior year amounts have been reclassified to conform to the current year presentation. These audited consolidated financial statements were approved by the Corporation’s Board of Directors on March 4, 2020.

3. SIGNIFICANT ACCOUNTING POLICIES

a. Principles of consolidation

The consolidated financial statements of the Corporation comprise the Corporation and its wholly-owned subsidiary, MEG Energy (U.S.) Inc. Earnings and expenses of its subsidiary are included in the consolidated balance sheet and consolidated statement of earnings (loss) and comprehensive income (loss). All intercompany transactions, balances, income and expenses are eliminated on consolidation.

b. Foreign currency translation

i. Functional and presentation currency

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which the Corporation operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation's functional currency.

ii. Transactions and balances

Foreign currency transactions are translated into Canadian dollars at exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in a foreign currency are translated into Canadian dollars at rates of exchange in effect at the end of the period. Foreign currency differences arising on translation are recognized in earnings or loss.

For the purposes of presenting consolidated financial statements, the assets and liabilities of the foreign subsidiary are translated into Canadian dollars at rates of exchange in effect at the end of the period. Revenue and expense items are translated at the average exchange rates prevailing at the dates of the transactions. Exchange differences arising, if any, are recognized in other comprehensive income (loss).

c. Financial instruments

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. A financial asset or liability is measured initially at fair value plus, for an item not measured at Fair Value Through Profit or Loss, transaction costs that are directly attributable to its acquisition or issuance.

Derivative financial instruments are recognized at fair value. Transaction costs are expensed in the consolidated statement of earnings (loss) and comprehensive income (loss). Gains and losses arising from changes in fair value are recognized in net earnings (loss) in the period in which they arise.

Financial assets and liabilities at Fair Value Through Profit or Loss are classified as current except where an unconditional right to defer payment beyond 12 months exists. Derivative financial instruments are included on the balance sheet as either an asset or liability and are classified as current or non-current based on the contractual terms specific to the instrument.

Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Derivative financial instruments are included in fair value through profit or loss unless they are designated for hedge accounting. The Corporation may periodically use derivative financial instruments to manage commodity price, foreign currency and interest rate exposures. The Corporation’s commodity risk management contracts have been classified as fair value through profit or loss.

i. Financial assets

At initial recognition, a financial asset is classified as measured at: amortized cost, fair value through profit or loss or fair value through other comprehensive income depending on the business model and contractual cash flows of the instrument.

Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Corporation has transferred substantially all risks and rewards of ownership. A substantial modification to the terms of an existing financial asset results in the derecognition of the financial asset and the recognition of a new financial asset at fair value. In the event that the modification to the terms of an existing financial asset do not result in a substantial difference in the contractual cash flows the gross carrying amount of the financial asset is recalculated and the difference resulting from the adjustment in the gross carrying amount is recognized in earnings or loss.

ii. Financial liabilities

Financial liabilities are measured at amortized cost or fair value through profit or loss. Financial liabilities at amortized cost include accounts payable and accrued liabilities and long-term debt. Accounts payable and accrued liabilities are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Long-term debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

Financial liabilities are derecognized when the liability is extinguished. A substantial modification of the terms of an existing financial liability is recorded as an extinguishment of the original financial liability and the recognition of a new financial liability. The difference between the carrying amount of a financial liability extinguished and the consideration paid is recognized in earnings or loss. Where a financial liability is modified in a way that does not constitute an extinguishment (generally when there is a change of less than 10% in the present value of cash flows discounted at the original effective interest rate), the modified cash flows are discounted at the liability's original effective interest rate. Transaction costs paid to third parties in a modification are amortized over the remaining term of the modified debt.

d. Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held with banks, and other short-term highly liquid investments such as bankers' acceptances, commercial paper, money market deposits or similar instruments, with a maturity of 90 days or less.

e. Trade receivables and other

Trade receivables are recorded based on the Corporation's revenue recognition policy as described in Note 3(p). Any impairments are determined based on the Corporation's impairment policy as described in Note 3(k)(i).

f. Inventories

Inventories consist of crude oil products and materials and supplies. Inventory is valued at the lower of cost and net realizable value. The cost of bitumen blend inventory is determined on a weighted average cost basis and the cost of diluent inventory is based on purchase price. Costs include direct and indirect expenditures incurred in the normal course of business in bringing an item or product to its existing condition and location. Net realizable value is the estimated selling price less applicable selling expenses. If the carrying value exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if the inventory is still on hand but the circumstances which caused the write-down no longer exist.

g. Exploration and evaluation assets

Exploration and evaluation ("E&E") expenditures, including the costs of acquiring licenses, technical studies, seismic, exploration drilling and evaluation and directly attributable general and administrative costs, including related borrowing costs, are initially capitalized as exploration and evaluation assets. Costs incurred prior to obtaining a legal right or license to explore are expensed in the period in which they are incurred.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. Upon determination of proved or probable reserves, E&E assets attributable to those reserves are tested for impairment upon reclassification to property, plant and equipment. If it is determined that an E&E asset is not technically feasible or commercially viable or facts and circumstances suggest that the carrying amount exceeds the recoverable amount, and the Corporation decides to discontinue the exploration and evaluation activity, the unrecoverable costs are charged to expense.

An E&E asset is derecognized upon disposal and any gains or losses from disposition are recognized in net earnings or loss.

h. Property, plant and equipment

Property, plant and equipment ("PP&E") is measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Assets under construction are not subject to depletion and depreciation. When significant parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components).

i. Crude oil

Crude oil assets consist of field production assets, major facilities and equipment, and planned major inspections, overhaul and turnaround activities. Included in the costs of these assets are the acquisition, construction, development and production of crude oil sands properties and reserves, including directly attributable overhead and administrative costs, related borrowing costs and estimates of decommissioning liability costs.

Field production assets are depleted using the unit-of-production method based on estimated proved reserves. Costs subject to depletion include estimated future development costs required to develop and produce the proved reserves. These estimates are reviewed by independent reserve engineers at least annually.

Major facilities and equipment are depreciated on a unit-of-production basis over the estimated total productive capacity of the facilities.

Costs of planned major inspections, overhaul and turnaround activities that maintain PP&E and benefit future years of operations are capitalized and depreciated on a straight-line basis over the period to the next turnaround. Recurring planned maintenance activities performed on shorter intervals are expensed. Replacements of equipment are capitalized when it is probable that future economic benefits will flow to the Corporation.

ii. Transportation and storage

Transportation and storage assets consist primarily of land and a pipeline associated with the Bruderheim Terminal. The net carrying values of transportation and storage assets are depreciated on a straight-line basis over their estimated useful lives, except for land which is not depreciated.

iii. Right-of-use ("ROU") assets

Right-of-use assets consist primarily of corporate office leases and transportation and storage leases. ROU assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term.

iv. Corporate assets

Corporate assets consist primarily of office equipment, computer hardware and leasehold improvements. Depreciation of office equipment is provided over the useful life of the assets on the declining balance basis at 25% per year. Leasehold improvements are depreciated on a straight-line basis over the term of the lease.

v. Asset dispositions

Property, plant and equipment assets are derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising from derecognition of the asset is determined as the difference between the net disposal proceeds, if any, and the carrying amount of the asset, and is recognized in net earnings or loss, unless the disposition is part of a sale and leaseback. The amount of consideration to be included in the gain or loss arising from derecognition is determined by the transaction contract.

Dispositions of property, plant and equipment occur on the date the acquiror obtains control of the asset.

i. Intangible assets

Intangible assets acquired by the Corporation which have a finite useful life are carried at cost less accumulated depreciation. Subsequent expenditures are capitalized only to the extent that they increase the future economic benefits embodied in the asset to which they relate. The Corporation incurs costs associated with research and development. Expenditures during the research phase are expensed. Expenditures during the development phase are capitalized only if certain criteria, including technical feasibility and the intent to develop and use the technology, are met. If these criteria are not met, the costs are expensed as incurred. The cost associated with purchasing or creating software which is not an integral component of the related computer hardware is included within intangible assets. The net carrying value of software is amortized over the estimated useful life of the asset on the declining balance basis at 25% per year.

j. Leases

Policy Applicable From January 1, 2019

The Corporation assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration.

As Lessee

Leases are recognized as a lease liability and a corresponding ROU asset at the date on which the leased asset is available for use by the Corporation. Liabilities and assets arising from a lease are initially measured on a present value basis. Lease liabilities are measured at the present value of the remaining lease payments, discounted using the Corporation's estimated incremental borrowing rate when the rate implicit in the lease is not readily available. The corresponding ROU assets are measured at the amount equal to the lease liability.

The lease liability is remeasured when there is a change in the future lease payments arising from a change in an index or rate, if there is a change in the amount expected to be payable under a residual value guarantee or if there is a change in the assessment of whether the Corporation will exercise a purchase, extension or termination option that is within the control of the Corporation.

The ROU asset, initially measured at an amount equal to the corresponding lease liability, is depreciated on a straight-line basis, over the shorter of the estimated useful life of the asset or the lease term. The ROU asset may be adjusted for certain re-measurements of the lease liability and impairment losses.

Upon adoption of IFRS 16, the Corporation recognized an increase to depletion and depreciation expense on ROU assets, an increase to net finance expense on lease liabilities, a reduction to general and administrative expense and a reduction to transportation expense. Accounting treatment of existing sale and leasebacks resulting in a finance lease under IAS 17 remained unchanged.

Lease payments are allocated between the lease liability and finance costs. Cash outflows for repayment of the principal portion of the lease liability is classified as cash flows from financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

Leases that have terms of less than twelve months or leases on which the underlying asset is of low value are recognized as an expense in the consolidated statement of earnings (loss) on a straight-line basis over the lease term.

As Lessor

Accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, and disclosure requirements are enhanced. As an intermediate lessor, the Corporation accounts for its interest in head leases and subleases separately. Upon adoption of IFRS 16, the Corporation reassessed subleases previously classified as operating leases under IAS 17 to determine whether each sublease should be classified as an operating lease or a finance lease. Operating leases that were reclassified to finance leases were accounted for as a new finance lease entered into on January 1, 2019.

Policy Applicable Before January 1, 2019

Leases where the Corporation assumes substantially all the risks and rewards of ownership are classified as finance leases within PP&E. At the commencement of the lease term, the Corporation recognizes the finance lease as an asset and a corresponding liability on the consolidated balance sheet at an amount equal to the lower of its fair value and the present value of the minimum lease payments. The Corporation's estimated incremental borrowing rate is used to calculate the present value of the minimum lease payments.

Minimum lease payments are apportioned between the finance charge and the reduction of the finance lease liability. Finance charges are charged directly against income through Net Finance Expense. The finance lease liability is accreted over the life of the lease and reduced by actual lease payments.

All other leases are operating leases, which are recognized as an expense as incurred over the lease term. When lease inducements are received to enter into operating leases, such inducements are recognized as a deferred liability. The aggregate benefit of inducements is recognized as a reduction of the related lease expense on a straight-line basis, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed.

A sale and leaseback transaction involves the sale of an asset and the leasing back of the same asset. If a sale and leaseback transaction results in a finance lease, any excess of sales proceeds over the carrying amount is not immediately recognized as income by the Corporation as a seller-lessee. Instead, the excess is deferred and amortized over the lease term. If a sale and leaseback results in an operating lease, and it is clear that the transaction is established at fair value, any profit or loss is recognized immediately.

k. Impairments

i. Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired.

Loss allowances are measured at an amount equal to the lifetime expected credit losses on the asset. Expected credit losses are a probability-weighted estimate of credit losses and are measured as the present value of all cash shortfalls for financial assets that are not credit-impaired at the reporting date and as the difference between the gross carrying amount and the present value of estimated future cash flows for financial assets that are credit-impaired at the reporting date. Loss allowances for expected credit losses for financial assets measured at amortized cost are presented in the statement of financial position as a deduction from the gross carrying amount of the asset.

ii. Non-financial assets

PP&E and E&E assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated. Intangible assets that are not yet available for use are tested for impairment annually. E&E assets are assessed for impairment immediately prior to being reclassified to PP&E.

For the purpose of impairment testing, PP&E assets are grouped into cash-generating units (“CGU”). A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. E&E assets are allocated to related CGU’s for impairment testing.

The recoverable amount of a CGU is the greater of its value in use and its fair value less costs of disposal. Value in use is estimated as the discounted present value of the expected future cash flows to be derived from the continuing use of the asset or CGU. In determining fair value less costs of disposal, recent market transactions are taken into account if available. In the absence of such transaction, an appropriate valuation model is used. An impairment loss is recognized in earnings or loss if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimate used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

l. Provisions

i. General

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are measured at the present value of the estimated future cash flows. Subsequent to the initial measurement, provisions are adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation as well as any changes in the discount rate.

ii. Decommissioning provision

The Corporation's activities give rise to dismantling, decommissioning and restoration activities. A provision is made for the estimated cost of decommissioning and restoration activities and capitalized in the relevant asset category.

Increases in the decommissioning provision due to the passage of time are recognized in net finance expense whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the obligations are charged against the decommissioning provision.

iii. Emissions obligations

When required, emission liabilities are recorded at the estimated cost required to settle the obligation. Emission compliance costs are expensed when incurred. Emission allowances granted to or internally generated by the Corporation are recognized as intangible assets at a nominal amount.

m. Deferred income taxes

The Corporation follows the liability method of accounting for income taxes. Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred taxes are not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. Deferred taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted as at the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority.

A deferred tax asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Income taxes are recognized in net earnings except to the extent that they relate to items recognized directly in shareholders' equity, in which case the income taxes are recognized in shareholders' equity.

n. Share capital

Common shares are classified as equity. Transaction costs directly attributable to the issuance of shares are recognized as a reduction of shareholders’ equity, net of any related income tax.

o. Share based payments

The Corporation’s share-based compensation plans include equity-settled awards and cash-settled awards. Compensation expense is recorded as stock based compensation expense or capitalized when the cost directly relates to exploration or development activities.

i. Equity-settled

The Corporation's Stock Option Plan and Treasury-Settled Restricted Share Unit Plan (the "Treasury-Settled RSU Plan") allows for the granting of equity-settled stock options, restricted share units (“RSUs”) and performance share units (“PSUs”) to directors, officers, employees and consultants. The grant date fair value of stock options, RSUs and PSUs is recognized as stock-based compensation expense, with a corresponding increase in contributed surplus, over the vesting period of the options, RSUs and PSUs. Each tranche in an award is considered a separate grant with its own vesting period and grant date fair value. Fair value is determined using the Black-Scholes option pricing model. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options, RSUs and PSUs that vest.

The Corporation's Treasury-Settled RSU Plan allows the holder of an RSU or PSU to receive a cash payment or its equivalent in fully-paid common shares, at the Corporation's discretion, equal to the fair market value of the Corporation's common shares calculated at the date of such payment. The Corporation does not intend to make cash payments under the Treasury-Settled RSU Plan and, as such, the RSUs and PSUs are accounted for within shareholders' equity. On exercise of stock options, the cash consideration received by the Corporation is credited to share capital and the associated amount in contributed surplus is reclassified to share capital.

ii. Cash-settled

The Corporation's Cash-Settled Restricted Share Unit Plan (the "Cash-Settled RSU Plan") allows for the granting of cash-settled RSUs and PSUs to directors, officers, employees and consultants. 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. The fair value is recognized as stock-based compensation over the vesting period. Fluctuations in the fair value are recognized within stock-based compensation in the period in which they occur.

The Corporation's Cash-Settled RSU Plan allows the holder of an RSU or PSU to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment.

The Corporation grants cash-settled deferred share units (“DSUs”) to directors of the Corporation. A DSU represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares purchased through a broker. DSUs are accounted for as liability instruments and are measured at fair value based on the market price of the Corporation’s common shares. The fair value of a DSU is recognized as stock-based compensation expense on the grant date and future fluctuations in the fair value are recognized as stock-based compensation expense in the period in which they occur.

p. Revenue recognition

The Corporation earns revenue primarily from the sale of crude oil, with other revenue earned from excess power generation, and from transportation fees charged to third parties.

i. Petroleum revenue and royalties

The Corporation sells proprietary and purchased crude oil under contracts of varying terms of up to one year to customers at prevailing market prices, whereby delivery takes place throughout the contract period. In most cases, consideration is due when title has transferred and is generally collected in the month following the month of delivery.

The Corporation evaluates its arrangements with third parties to determine if the Corporation acts as the principal or as an agent. In making this evaluation, management considers if the Corporation obtains control of the product delivered. If the Corporation acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the Corporation from the transaction.

Revenues associated with the sales of proprietary and purchased crude oil owned by the Corporation are recognized at a point in time when control of goods have transferred, which is generally when title passes from the Corporation to the customer. Revenues are recorded net of crown royalties. Crown royalties are recognized at the time of production.

Revenue is allocated to each performance obligation on the basis of its standalone selling price and measured at the transaction price, which is the fair value of the consideration and represents amounts receivable for goods or services provided in the normal course of business. The price is allocated to each unit in the series as each unit is substantially the same and depicts the same pattern of transfer to the customer.

ii. Other revenue

Revenue from power generated in excess of the Corporation's internal requirements is recognized upon delivery from the plant gate, at which point, control is transferred to the customer on the power grid. Revenues are earned at prevailing market prices for each megawatt hour produced. Fees charged to customers for the use of pipelines and facilities are recognized in the period when the products are delivered and the services are provided.

q. Net earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing the net earnings (loss) for the period attributable to common shareholders of the Corporation by the weighted average number of common shares outstanding during the period.

Diluted earnings (loss) per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to stock options, RSUs and PSUs is computed using the treasury stock method. The Corporation's potentially dilutive instruments comprise stock options, and equity-settled RSUs and PSUs granted to directors, officers, employees and consultants.

r. New accounting standards

The Corporation has adopted the following standards effective January 1, 2019:

i. IFRS 16 Leases

The IASB issued IFRS 16, *Leases* ("IFRS 16"), which replaces IAS 17 *Leases*, and is effective for annual periods beginning on or after January 1, 2019. IFRS 16, a single recognition and measurement model applicable to lessees, requires recognition of lease assets and lease liabilities on the balance sheet. The standard eliminates the classification of leases as either operating leases or finance leases for lessees, essentially treating all leases as finance leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases. The accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases.

The Corporation adopted IFRS 16 *Leases,* effective January 1, 2019, using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period comparative financial information as the cumulative effect is recognized as an adjustment to the opening deficit on the transition date and the standard is applied prospectively. Therefore, the comparative information in the Corporation's condensed Consolidated balance sheet, Consolidated statement of earnings (loss) and comprehensive income, Consolidated statement of changes in shareholders' equity, and Consolidated statement of cash flow have not been restated.

On adoption of IFRS 16, the Corporation elected to use the following practical expedients permitted by the standard:

- Applied a single discount rate to a portfolio of leases with similar characteristics;
- Accounted for leases with a remaining term of less than 12 months as at January 1, 2019 as short-term leases;
- Used hindsight when determining the lease term where the contract contained options to extend or terminate the lease;
- Excluded initial direct costs from the measurement of the right-of-use ("ROU") asset as at January 1, 2019; and

  Relied on the Corporation’s previous assessment of whether leases were onerous under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* immediately before initial application as an alternative to performing an impairment review on the ROU assets. ROU assets have been adjusted by the amount of the onerous contracts provision recognized in the consolidated financial statements as at December 31, 2018.

The impacts of the adoption of IFRS 16, as at January 1, 2019, are as follows:

		IFRS 16 Opening Balance Sheet Adjustments			
	Reported balance as at Dec 31, 2018	**Finance Sublease Receivables[(a)]**	**Transportation Leases[(b)]**	**Office Leases[(b)]**	**Restated balance as at January 1, 2019**
Assets					
Property, plant and equipment	$ 6,646		$ 17	$ 41	$ 6,704
Other assets	221	$ 19			240
Deferred income tax asset	237	(5)		1	233
Liabilities					
Provisions and other liabilities	(294)		(17)	(44)	(355)
Shareholders' Equity					
Deficit	1,751	(14)		2	1,739
	$ 8,561	**$ —**	**$ —**	**$ —**	**$ 8,561**

a. On adoption, the Corporation has recognized finance sublease receivables in relation to certain sublease arrangements that were previously recognized on the consolidated balance sheet as at December 31, 2018 within the onerous contracts provision.

b. On adoption, the Corporation has recognized lease liabilities in relation to lease arrangements measured at the present value of the remaining lease payments as at December 31, 2018, and discounted using the Corporation’s estimated incremental borrowing rate as of January 1, 2019. The associated ROU assets were measured at the amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, on January 1, 2019.

Reconciliation of Commitments to Lease Liabilities

The following table provides a reconciliation of the commitments as at December 31, 2018 to the Corporation's lease liabilities as at January 1, 2019:

		Reconciliation
Commitments as at December 31, 2018	$	9,026
Less:		
Agreements that do not contain a lease		(8,842)
Non-lease components		(64)
Short-term and immaterial leases		(12)
Impact of discounting		(25)
		83
Add:		
Finance lease liabilities under IAS 17		131
Provisions previously recognized under IAS 37		77
Lease liabilities as at January 1, 2019	**$**	**291**

4. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGMENTS

The timely preparation of the consolidated financial statements requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ materially from estimated amounts as future confirming events occur. Significant judgments, estimates and assumptions made by management in the preparation of these consolidated financial statements are outlined below.

a. Property, plant and equipment

Field production assets within PP&E are depleted using the unit-of-production method based on estimates of proved bitumen reserves and future costs required to develop those reserves. There are a number of inherent uncertainties associated with estimating reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

Amounts recorded for depreciation of major facilities and equipment and transportation and storage assets are based on management's best estimate of their useful lives and the facilities' productive capacity. Accordingly, those amounts are subject to measurement uncertainty.

In addition, management is required to make estimates and assumptions and use judgment regarding the timing of when major development projects are ready for their planned use, which also determines when these assets are subject to depletion and depreciation.

b. Exploration and evaluation assets

The application of the Corporation's accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined and when technical feasibility and commercial viability have been reached. Estimates and assumptions may change as new information becomes available.

c. Bitumen reserves

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the cost and timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Corporation expects that over time its reserves estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion and depreciation charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of PP&E carrying amounts.

d. Decommissioning provision

Decommissioning costs are incurred when certain of the Corporation's tangible long-lived assets are retired. Assumptions are made to estimate the future liability based on current economic factors. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and reclamation. The impact to net earnings over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. In addition, management exercises judgment to determine the appropriate discount rate at the end of each reporting period. This discount rate, which is a credit-adjusted risk-free rate, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

e. Impairments

CGU's are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGU's requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures, and the way in which management monitors the Corporation's operations.

The recoverable amounts of CGU's and individual assets have been determined as the higher of the CGU's or the asset's fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGU's.

f. Stock-based compensation

The fair values of equity-settled and cash-settled share-based compensation plans are estimated using the Black-Scholes options pricing model. These estimates are based on the Corporation's share price and on several assumptions, including the risk-free interest rate, the future forfeiture rate, the expected volatility of the Corporation's share price and the future attainment of performance criteria. Accordingly, these estimates are subject to measurement uncertainty.

g. Deferred income taxes

Tax regulations and legislation and the interpretations thereof in which the Corporation operates are subject to change. As such, income taxes are subject to measurement uncertainty.

Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date. The periods in which timing differences reverse are impacted by future earnings and capital expenditures. Rates are also affected by changes to tax legislation.

The Corporation also makes interpretations and judgments on the application of tax laws for which the eventual tax determination may be uncertain. To the extent that interpretations change, there may be a significant impact on the consolidated financial statements.

h. Derivative financial instruments

The estimated fair values of financial assets and liabilities are subject to measurement uncertainty due to their exposure to credit, liquidity and market risks. Furthermore, the Corporation may use derivative instruments to manage commodity price, foreign currency and interest rate exposures. The fair values of these derivatives are determined using 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 quoted forward commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and as such are subject to measurement uncertainty.

i. Leases

The Corporation applies judgment in reviewing each of its contractual arrangements to determine whether the arrangement contains a lease within the scope of IFRS 16. Leases that are recognized are subject to further judgment and estimation in various areas specific to the arrangement.

When a lease contract contains an option to extend or terminate a lease, the Corporation must use their best estimate to determine the appropriate lease term. Management must consider all facts and circumstances to determine if there is an economic benefit to exercise an extension option or to not exercise a termination option. The lease term must be reassessed if a significant event or change in circumstance occurs.

Lease liabilities recognized have been estimated using a discount rate equal to the Corporation's estimated incremental borrowing rate. This rate represents the rate that the Corporation would incur to obtain the funds necessary to purchase an asset of a similar value, with similar payment terms and security in a similar economic environment.

5. TRADE RECEIVABLES AND OTHER

As at December 31		**2019**		**2018**
Trade receivables	**$**	**359**	$	200
Deposits and advances		**18**		10
Current portion of deferred financing costs		**3**		8
Current portion of sublease receivable		**2**		—
	$	**382**	$	218

6. INVENTORIES

As at December 31	2019	2018
Bitumen blend	**$ 73**	$ 74
Diluent	**13**	17
Material and supplies	**7**	6
	$ 93	$ 97

During the year ended December 31, 2019, a total of $1.2 billion (2018 - $1.3 billion) in inventory product costs were charged to earnings through diluent and transportation expense.

7. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Right-of-use assets	Corporate assets	Total
Cost					
Balance as at December 31, 2017	$ 8,298	$ 1,618	$ —	$ 76	$ 9,992
Additions	619	5	196	1	821
Transfers to other assets (Note 9)	—	(67)	—	—	(67)
Dispositions	—	(1,397)	—	—	(1,397)
Change in decommissioning liabilities	(37)	—	—	—	(37)
Balance as at December 31, 2018	$ 8,880	$ 159	$ 196	$ 77	$ 9,312
IFRS 16 opening balance sheet adjustment	—	—	58	—	58
Additions	199	—	13	1	213
Dispositions	(3)	—	(4)	—	(7)
Change in decommissioning liabilities	1	—	—	—	1
Balance as at December 31, 2019	**$ 9,077**	**$ 159**	**$ 263**	**$ 78**	**$ 9,577**
Accumulated depletion and depreciation					
Balance as at December 31, 2017	$ 2,184	$ 141	$ —	$ 33	$ 2,358
Depletion and depreciation	426	17	5	6	454
Dispositions	—	(146)	—	—	(146)
Balance as at December 31, 2018	$ 2,610	$ 12	$ 5	$ 39	$ 2,666
Depletion and depreciation	592	90	20	6	708
Dispositions	(3)	—	—	—	(3)
Balance as at December 31, 2019	**$ 3,199**	**$ 102**	**$ 25**	**$ 45**	**$ 3,371**
Carrying amounts					
Balance as at December 31, 2018	$ 6,270	$ 147	$ 191	$ 38	$ 6,646
Balance as at December 31, 2019	**$ 5,878**	**$ 57**	**$ 238**	**$ 33**	**$ 6,206**

On adoption of IFRS 16, the Corporation recognized right-of-use assets of $58 million in relation to corporate office lease arrangements and transportation and storage lease arrangements measured at the present value of the remaining lease payments as at December 31, 2018, and discounted using the Corporation's estimated incremental borrowing rate as of January 1, 2019. These right-of-use assets were measured at the amount equal to the lease liability on January 1, 2019.

During the second quarter of 2019, accelerated depreciation totaling $237 million was recognized on equipment, materials and engineering costs associated with greenfield expansion projects at Christina Lake which will not be pursued in the foreseeable future plus a partial upgrading technology project.

As at December 31, 2019, property, plant and equipment was assessed for impairment and no impairment was recognized. Included in the cost of property, plant and equipment is $229 million of assets under construction as at December 31, 2019 (December 31, 2018 – $291 million).

8. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2017	$	549
Additions		3
Exploration expense		(1)
Change in decommissioning liabilities		(1)
Balance as at December 31, 2018	$	550
Additions		1
Exploration expense		(58)
Dispositions		(3)
Balance as at December 31, 2019	**$**	**490**

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. An assessment of existing assets was completed during the second quarter of 2019. The Corporation decided not to continue exploration and evaluation activities in its Duncan area growth properties and has included associated land lease and evaluation costs totaling $58 million as exploration expense as at December 31, 2019. During the year ended December 31, 2019, the Corporation sold lands with a carrying value of $3 million for proceeds of $5 million.

As at December 31, 2019, exploration and evaluation assets were assessed for impairment and no impairment was recognized.

9. OTHER ASSETS

As at	December 31, 2019	December 31, 2018
Non-current pipeline linefill[(a)]	**$ 190**	$ 194
Finance sublease receivables[(b)]	**18**	—
Intangible assets[(c)]	**9**	11
Deferred financing costs	**7**	15
Prepaid transportation costs[(d)]	**9**	9
	233	229
Less current portion	**(6)**	(8)
	$ 227	$ 221

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 2020 and 2048. As a result of the sale of the Corporation's 50% interest in Access Pipeline and its 100% interest in the Stonefell Terminal in the first quarter of 2018, $67 million of the associated pipeline linefill was transferred from property, plant and equipment to other assets. As at December 31, 2019, no impairment has been recognized on these assets.

b. On adoption of IFRS 16, the Corporation recognized finance sublease receivables in relation to certain sublease arrangements that were previously recognized on the consolidated balance sheet as at December 31, 2018 within the onerous contracts provision. The IFRS 16 opening balance sheet adjustment related to finance sublease receivables was $19 million as at January 1, 2019.

c. As at December 31, 2019, intangible assets consist of $9 million invested in software that is not an integral component of the related computer hardware (December 31, 2018 – $11 million). Depreciation of $2 million was recognized for the year ended December 31, 2019 (December 31, 2018 – $3 million). During the year ended December 31, 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.

d. 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.

10. LONG-TERM DEBT

As at December 31	2019	2018
Senior secured term loan (December 31, 2019 – nil; December 31, 2018 – US$225 million)[a]	**$ —**	$ 307
6.375% senior unsecured notes (US$800 million; due 2023)[b]	**1,037**	1,092
7.0% senior unsecured notes (US$1 billion; due 2024)[c]	**1,297**	1,365
6.5% senior secured second lien notes (December 31, 2019 - US$596 million; December 31, 2018 – US$750 million; due 2025)[d]	**773**	1,023
	3,107	3,787
Debt redemption premium[e]	**29**	—
Less unamortized deferred debt discount and debt issue costs	**(13)**	(29)
Less unamortized financial derivative liability discount	**—**	(1)
	3,123	3,757
Less current portion of senior secured term loan	**—**	(17)
	$ 3,123	$ 3,740

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2965 (December 31, 2018 – US$1 = C$1.3646).

a. On March 27, 2018, subsequent to the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell terminal, a majority of the net cash proceeds were used to repay approximately $1.2 billion of the senior secured term loan. The repayment of debt reduced the estimated amortization period of the unamortized debt discount and debt issue costs, and the unamortized financial derivative liability discount.

   On July 30, 2019, the Corporation repaid the outstanding senior secured term loan balance of $289 million (US $219 million).

   Concurrent with the senior secured term loan repayment, the Corporation amended and restated its revolving credit facility and the EDC Facility and extended the maturity date of each facility by 2.75 years to July 30, 2024. The maturity dates of the revolving credit facility and the EDC Facility include a feature that will 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 Corporation reduced the total available credit under the two facilities from US$1.8 billion to C$1.3 billion. The C$1.3 billion facility is now comprised of C$800 million under the revolving credit facility and C$500 million under the EDC Facility. As at December 31, 2019, the Corporation had not drawn on its revolving credit facility and had C$99 million of unutilized capacity under the EDC Facility.

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 drawn in excess of $400 million, under the revolving credit facility 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 revolving credit facility, EDC facility and senior secured second lien notes are secured by substantially all the assets of the Corporation.

b. Effective July 19, 2012, the Corporation issued US$800 million in aggregate principal amount of 6.375% senior unsecured notes, with a maturity date of January 30, 2023. Interest is paid semi-annually on January 30 and July 30. No principal payments are required until January 30, 2023.

c. Effective October 1, 2013, the Corporation issued US$800 million in aggregate principal amount of 7.0% senior unsecured notes, with a maturity date of March 31, 2024. On November 6, 2013 an additional US$200 million of 7.0% senior unsecured notes were issued under the same indenture. Interest is paid semi-annually on March 31 and September 30. No principal payments are required until March 31, 2024. The Corporation has deferred the associated debt issue costs of $13 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

d. Effective January 27, 2017, the Corporation issued US$750 million in aggregate principal amount of 6.5% senior secured second lien notes, with a maturity date of January 15, 2025. Interest is paid semi-annually in January and July. No principal payments are required until January 15, 2025. The Corporation has deferred the associated debt issue costs of $18 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

   During the year ended December 31, 2019, the Corporation repurchased and extinguished a portion of its 6.5% senior secured second lien notes totaling $204 million (US$154 million) in aggregate principal amount.

e. Subsequent to December 31, 2019 and consistent with the Corporation's strategic focus on maintaining long term financial liquidity while pursuing ongoing debt repayment, the Corporation successfully closed a private offering of US$1.2 billion in aggregate principal amount of 7.125% senior unsecured notes due February 2027. The net proceeds of the offering, together with cash on hand, were used to:

   - Fully redeem US$800 million in aggregate principal amount of 6.375% senior unsecured notes due January 2023 at a redemption price of 101.063%;
   - Partially redeem US$400 million of the US$1.0 billion aggregate principal amount of 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, the Corporation redeemed US$100 million 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.

11. PROVISIONS AND OTHER LIABILITIES

As at December 31		2019		2018
Lease liabilities[a]	**$**	**281**	$	131
Decommissioning provision[b]		**71**		65
Onerous contracts provision[c]		**—**		78
Deferred lease inducements[d]		**—**		21
Other liabilities		**8**		16
Provisions and other liabilities		**360**		311
Less current portion		**(28)**		(17)
Non-current portion	**$**	**332**	$	294

a. Lease liabilities:

As at December 31		2019		2018
Balance, beginning of year	**$**	**131**	$	—
IFRS 16 opening balance sheet adjustment		**160**		—
Additions		**13**		130
Modifications		**(4)**		—
Payments		**(45)**		(12)
Interest expense		**26**		13
Balance, end of period		**281**		131
Less current portion		**(22)**		—
Non-current portion	**$**	**259**	$	131

On adoption of IFRS 16, the Corporation recognized lease liabilities of $160 million in relation to corporate office space and marketing storage arrangements measured at the present value of the remaining lease payments as at January 1, 2019, and discounted using the Corporation's estimated incremental borrowing rate of 6.0% for assets over a similar term with similar security, determined in accordance with IFRS 16. The associated right-of-use assets were measured at the amount equal to the lease liabilities on January 1, 2019.

The Corporation's minimum lease payments are as follows:

As at December 31		2019
Within one year	**$**	**48**
Later than one year but not later than five years		**140**
Later than five years		**529**
Minimum lease payments		**717**
Amounts representing finance charges		**(436)**
Net minimum lease payments	**$**	**281**

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 December 31, 2019, the present value of these arrangements is $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 December 31		2019		2018
Balance, beginning of year	**$**	**65**	$	103
Changes in estimated life and estimated future cash flows		**(2)**		(5)
Changes in discount rates		**2**		(39)
Liabilities incurred and disposed, net		**1**		5
Liabilities settled		**(2)**		(5)
Accretion		**7**		6
Balance, end of period		**71**		65
Less current portion		**(5)**		(3)
Non-current portion	**$**	**67**	$	62

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 $827 million (December 31, 2018 – $719 million). The Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 13.7% (December 31, 2018 – 14.1%) and an inflation rate of 2.1% (December 31, 2018 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2018 - periods up to the year 2067).

c. Onerous contracts provision:

On adoption of IFRS 16, the Corporation elected to use the practical expedient and rely on its previous assessment of whether leases were onerous under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets,* immediately before initial application, as an alternative to performing an impairment review. As a result, the Corporation recognized a right-of-use asset of $78 million on January 1, 2019 equivalent to the amount of the onerous contracts provision recognized in the consolidated financial statements as at December 31, 2018.

d. Deferred office building lease inducements:

On adoption of IFRS 16, the Corporation recognized an opening balance sheet adjustment of $19 million related to deferred office building lease inducements.

12. INCOME TAX

Year ended December 31	2019	2018
Loss before income taxes	$ (91)	$ (168)
Statutory income tax rate	26.5%	27.0%
Expected income tax expense (recovery)	(24)	(45)
Add (deduct) the tax effect of:		
Stock-based compensation	6	6
Non-taxable loss (gain) on foreign exchange	(24)	46
Taxable capital loss (gain) not recognized	(23)	46
Non-taxable loss (gain) on sale of assets	—	(49)
Taxable loss (gain) sheltered by losses	—	(49)
Tax benefit of vested RSUs	(3)	(4)
Alberta tax rate reduction	33	—
Other	6	—
Income tax expense (recovery)	$ (29)	$ (49)
Current income tax expense (recovery)	—	$ 1
Deferred income tax expense (recovery)	(29)	(50)
Income tax expense (recovery)	$ (29)	$ (49)

On June 28, 2019, the Government of Alberta enacted legislation which will reduce the corporate tax rate from 12% to 8% by January 1, 2022. A one-time deferred income tax expense of $33 million related to the Alberta tax rate reduction was recognized during the year ended December 31, 2019.

As at December 31, 2019, the Corporation has recognized a deferred tax asset of $262 million (December 31, 2018 - $237 million). Future taxable income is expected to be sufficient to realize the deferred tax asset. 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.

The deferred tax assets (liabilities) consist of the following:

As at December 31	2019	2018
Deferred tax assets:		
Deferred tax assets to be recovered after more than 12 months	$ 1,273	$ 1,420
Deferred tax assets to be recovered within 12 months	33	12
	$ 1,306	$ 1,432
Deferred tax liabilities:		
Deferred tax liabilities to be recovered after more than 12 months	$ (1,013)	$ (1,216)
Deferred tax liabilities to be recovered within 12 months	(31)	(27)
	$ (1,044)	$ (1,243)
Deferred tax assets (liabilities), net	$ 262	$ 237

The net movement within the deferred tax assets (liabilities) is as follows:

	2019	2018
Balance as at January 1	**$ 237**	$ 183
Credited (charged) to earnings	**29**	50
Credited (charged) to equity	**(4)**	4
Balance as at December 31	**$ 262**	$ 237

The movements in deferred income tax assets and liabilities during the years are as follows:

Deferred tax assets	**Tax losses**	**Commodity risk management**	**Decommissioning provision**	**Right-of-use assets**	**Other**	**Total**
Balance as at December 31, 2017	$ 1,331	$ 18	$ 28	$ —	$ 57	$ 1,434
Credited (charged) to earnings	38	(18)	(10)	35	(3)	42
Credited (charged) to equity	2	—	—	—	2	4
Balance as at December 31, 2018	**1,371**	**—**	**18**	**35**	**56**	**1,480**
Credited (charged) to earnings	**(205)**	**18**	**(1)**	**13**	**(6)**	**(181)**
Credited (charged) to equity	**—**	**—**	**—**	**12**	**(5)**	**7**
Balance as at December 31, 2019	**$ 1,166**	**$ 18**	**$ 17**	**$ 60**	**$ 45**	**$ 1,306**

Deferred tax liabilities	**Property, plant and equipment**	**Commodity risk management**	**Other**	**Total**
Balance as at December 31, 2017	$ (1,250)	$ —	$ (1)	$ (1,251)
Credited (charged) to earnings	32	(25)	1	8
Balance as at December 31, 2018	**(1,218)**	**(25)**	**—**	**(1,243)**
Credited (charged) to earnings	**185**	**25**	**—**	**210**
Credited (charged) to equity	**(11)**	**—**	**—**	**(11)**
Balance as at December 31, 2019	**$ (1,044)**	**$ —**	**$ —**	**$ (1,044)**

As at December 31, 2019, the Corporation had approximately $7.3 billion in available tax pools (December 31, 2018 - $7.7 billion). Included in the tax pools are $5.1 billion of non-capital loss carry forward balances expiring as follows:

	2026	2027	2028	2029	2030	Thereafter	Total
Non-capital loss carry forward balances	$ 200	$ 200	$ 300	$ 500	$ 200	$ 3,700	$ 5,100

In addition, as at December 31, 2019, the Corporation had an additional $101 million (December 31, 2018 - $73 million) of capital investment in incomplete projects which will serve to increase available tax pools upon completion of the projects. As at December 31, 2019, the Corporation had not recognized the tax benefit related to $343 million of realized and unrealized taxable capital foreign exchange losses (December 31, 2018 - $435 million).

13. 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:

	2019			2018		
	Number of shares (thousands)		**Amount**	**Number of shares (thousands)**		**Amount**
Balance, beginning of year	**296,841**	**$**	**5,427**	294,104	$	5,404
Issued upon exercise of stock options	**266**		**2**	212		2
Issued upon vesting and release of RSUs and PSUs	**2,401**		**14**	2,525		21
Balance, end of period	**299,508**	**$**	**5,443**	296,841	$	5,427

14. STOCK-BASED COMPENSATION

The Corporation has a number of stock-based compensation plans which include stock options, restricted share units ("RSUs"), performance share units ("PSUs") and deferred share units ("DSUs"). Further detail on each of these plans is outlined below.

a. Cash-settled plans

i. Restricted share units and performance share units:

RSUs granted under the Cash-Settled RSU plan generally vest annually in thirds over a three-year period. PSUs granted under the Cash-Settled RSU plan generally vest on the third anniversary of the grant date, provided that the Corporation satisfies certain performance criteria identified by the Corporation's Board of Directors which are set and measured annually to establish a performance multiplier from zero to two. The stock-based compensation expense for PSUs is determined based on an estimate of the final number of PSU awards that eventually vest based on the performance multiplier and the performance criteria.

Cash-settled RSUs and PSUs outstanding:

Year ended December 31 (expressed in thousands)	**2019**	**2018**
Outstanding, beginning of year	**4,263**	5,310
Granted	**2,285**	467
Vested and released	**(2,808)**	(1,397)
Forfeited	**(486)**	(117)
Outstanding, end of year	**3,254**	4,263

ii. Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of DSUs to directors of the Corporation. A DSU represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares purchased through a broker. DSUs vest immediately when granted and are redeemed on the earlier of (a) December 15 of the first calendar year starting after the date the holder ceases to be a member of the Corporation, and (b) the fifth business day following the date on which the holder delivers a redemption notice. As at December 31, 2019, there were 734,347 DSUs outstanding (December 31, 2018 – 342,775 DSUs outstanding).

As at December 31, 2019, the Corporation recognized a liability of $25 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2018 – $30 million). The current portion of $21 million is included within accounts payable and accrued liabilities and $4 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards.

b. Equity-settled plans

i. Stock options outstanding:

The Corporation's Stock Option Plan allows for the granting of stock options to directors, officers, employees and consultants of the Corporation. Stock options granted are generally fully exercisable after three years and expire seven years after the grant date.

Year ended December 31	**2019**		**2018**	
	Stock options (thousands)	**Weighted average exercise price**	**Stock options (thousands)**	**Weighted average exercise price**
Outstanding, beginning of year	**8,517**	**$ 21.27**	8,896	$ 23.81
Granted	**683**	**4.57**	798	9.03
Exercised	**(266)**	**5.20**	(212)	5.77
Forfeited	**(1,198)**	**21.60**	(439)	22.64
Expired	**(975)**	**35.69**	(526)	50.70
Outstanding, end of year	**6,761**	**$ 18.08**	8,517	$ 21.27

As at December 31, 2019	**Outstanding**			**Vested**		
Range of exercise prices	**Options (thousands)**	**Weighted average exercise price**	**Weighted average remaining life (in years)**	**Options (thousands)**	**Weighted average exercise price**	**Weighted average remaining life (in years)**
$4.53 - $10.00	2,853	$ 6.00	4.90	1,372	$ 6.02	4.03
$10.01 - $30.00	1,880	18.58	2.44	1,880	18.58	2.44
$30.01 - $38.68	2,028	34.60	0.98	2,028	34.60	0.98
	6,761	**$ 18.08**	**3.04**	**5,280**	**$ 21.47**	**2.29**

The fair value of each option granted during the years ended December 31, 2019 and 2018 was estimated on the date of the grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

Year ended December 31		2019		2018
Risk-free rate		**1.33%**		2.17%
Expected lives		**5 years**		5 years
Volatility(i)		**69%**		62%
Annual dividend per share		**nil**		nil
Weighted average strike price	**$**	**5.03**	$	8.96
Fair value of options granted	**$**	**2.89**	$	4.82

(i) Expected volatility is determined by the average price volatility of the Corporation's common shares over the past five years.

ii. Restricted share units and performance share units:

RSUs granted under the equity-settled Restricted Share Unit Plan generally vest annually in thirds over a three-year period. PSUs granted under the equity-settled Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that the Corporation satisfies certain performance criteria identified by the Corporation's Board of Directors which are set and measured annually to establish a performance multiplier from zero to two.

Equity-settled RSUs and PSUs outstanding:

Year ended December 31 (expressed in thousands)	2019	2018
Outstanding, beginning of year	**6,534**	6,308
Granted	**3,342**	3,273
Vested and released	**(2,401)**	(2,532)
Forfeited	**(1,082)**	(515)
Outstanding, end of year	**6,393**	6,534

c. Stock-based compensation

Year ended December 31		2019		2018
Cash-settled expense(i)	**$**	**7**	$	26
Equity-settled expense		**24**		21
Stock-based compensation	**$**	**31**	$	47

(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 for the year ended December 31, 2019 compared to the same period of 2018 due to the decrease in the Corporation's share price and a reduction in the number of share-based units resulting from reduced staffing levels. The decrease in total stock-based compensation was partially offset by a one-time charge of $10 million related to the accelerated expense of units for retirement eligible employees which was recorded during the second quarter of 2019.

15. REVENUES

Year ended December 31	2019	2018
Sales from:		
Production	**$ 2,996**	$ 2,503
Purchased products[i]	**907**	208
Petroleum revenue	**$ 3,903**	$ 2,711
Royalties	**(45)**	(38)
Petroleum revenue, net of royalties	**$ 3,858**	$ 2,673
Power revenue	**$ 60**	$ 48
Transportation revenue	**13**	12
Other revenue	**$ 73**	$ 60
	$ 3,931	$ 2,733

(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:

	Year ended December 31					
	2019			2018		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	**$ 1,820**	**$ 261**	**$ 2,081**	$ 1,435	$ 96	$ 1,531
United States	**1,176**	**646**	**1,822**	1,068	112	1,180
	$ 2,996	**$ 907**	**$ 3,903**	$ 2,503	$ 208	$ 2,711

Other revenue recognized during the years ended December 31, 2019 and 2018 is attributed to Canada.

b. Revenue-related assets

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

As at	December 31, 2019	December 31, 2018
Petroleum revenue	**$ 342**	$ 122
Other revenue	**9**	4
Total revenue-related assets	**$ 351**	$ 126

Revenue-related receivables are typically settled within 30 days. As at December 31, 2019 and December 31, 2018, there was no material expected credit loss required against revenue-related receivables.

16. DILUENT AND TRANSPORTATION

Year ended December 31		2019		2018
Diluent expense	**$**	**1,185**	$	1,281
Transportation and storage[a]		**383**		280
Diluent and transportation	**$**	**1,568**	$	1,561

a. On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline. Transportation expense includes incremental expenses associated with the related Transportation Services Agreement.

17. FOREIGN EXCHANGE (GAIN) LOSS, NET

Year ended December 31		2019		2018
Unrealized foreign exchange loss (gain) on:				
Long-term debt	**$**	**(180)**	$	346
US$ denominated cash and cash equivalents		**8**		(5)
Unrealized net loss (gain) on foreign exchange		**(172)**		341
Realized loss (gain) on foreign exchange		**(3)**		5
Realized loss (gain) on foreign exchange derivatives[a]		**—**		(35)
Foreign exchange loss (gain), net	**$**	**(175)**	$	311

C$ equivalent of 1 US$		
Beginning of period	**1.3646**	1.2518
End of period	**1.2965**	1.3646

a. On February 8, 2018, the Corporation entered into forward currency contracts to manage the foreign exchange risk on expected Canadian dollar denominated asset sale proceeds designated for U.S. dollar denominated long-term debt repayment. The forward currency contracts were settled on March 22, 2018, resulting in a realized gain of $35 million.

18. NET FINANCE EXPENSE

Year ended December 31		2019		2018
Interest expense on long-term debt	**$**	**267**	$	287
Interest expense on lease liabilities[a]		**26**		13
Interest income		**(5)**		(8)
Net interest expense		**288**		292
Debt extinguishment expense[b] [c]		**46**		—
Accretion on provisions		**7**		8
Unrealized (gain) loss on derivative financial liabilities		**(1)**		3
Realized (gain) loss on interest rate swaps[d]		**—**		(17)
Net finance expense	**$**	**340**	$	286

a. On adoption of IFRS 16, the Corporation recognized lease liabilities of $160 million in relation to corporate office space and marketing storage arrangements. These lease liabilities will be accreted through net finance expense over the life of each lease arrangement using the Corporation's estimated incremental borrowing rate of 6.0%, which is the rate determined for assets over a similar term with similar security, and is in accordance with IFRS 16.

b. Throughout the second half of 2019, the Corporation repurchased and extinguished $204 million (US$154 million) aggregate principal amount of its senior secured second lien notes. Included in debt extinguishment expense is a $4 million premium paid on the repurchase of the senior secured second lien notes and related unamortized deferred debt issue costs of $3 million.

c. Subsequent to December 31, 2019 and consistent with the Corporation's strategic focus on maintaining long term financial liquidity while pursuing ongoing debt repayment, the Corporation successfully closed a private offering of US$1.2 billion in aggregate principal amount of 7.125% senior unsecured notes due February 2027. The net proceeds of the offering, together with cash on hand, were used to:

   - Fully redeem US$800 million in aggregate principal amount of 6.375% senior unsecured notes due January 2023 at a redemption price of 101.063%;
   - Partially redeem US$400 million of the US$1.0 billion aggregate principal amount of 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, the Corporation redeemed US$100 million 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, debt extinguishment expense included a cumulative debt redemption premium of $29 million and associated unamortized deferred debt issue costs of $10 million.

d. In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650 million of its US$1.2 billion senior secured term loan at approximately 5.3%. In conjunction with the partial repayment of the senior secured term loan on March 27, 2018, the interest rate swap was terminated and a realized gain of $17 million was recognized.

19. OTHER EXPENSES

Year ended December 31		**2019**		**2018**
Severance		**11**	$	5
Research & development and other		**12**	$	6
Defense costs related to unsolicited bid[(a)]		**—**	$	19
Onerous contracts expense[(b)]		**—**		3
Other expenses	**$**	**23**	$	33

a. On October 2, 2018, Husky Energy Inc. ("Husky") issued an unsolicited Offer to Purchase and Bid Circular to acquire all of the outstanding common shares of the Corporation. On October 17, 2018, the Corporation issued a Directors' Circular recommending shareholders to reject Husky's offer. On January 17, 2019, Husky issued a press release stating that the takeover offer for the Corporation did not meet their minimum tender conditions and therefore did not extend the offer. During the fourth quarter of 2018, the Corporation incurred $19 million of costs related to Husky's offer.

b. Onerous contracts expense primarily includes changes in estimated future cash flow sublease recoveries related to the Corporation's onerous office building lease contracts.

20. OTHER INCOME

During the year ended December 31, 2019, the Corporation agreed to relieve the Alberta Petroleum Marketing Commission ("APMC") of all obligations pursuant to a Crude Oil Purchase and Sale Agreement in exchange for a payment of $20 million.

21. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the years ended December 31, 2019 and 2018, other than compensation of key management personnel. The Corporation considers directors and officers of the Corporation as key management personnel.

Year ended December 31	2019	2018
Share-based compensation	**$ 14**	$ 17
Salaries and short-term employee benefits	**9**	12
Termination benefits	**1**	4
	$ 24	$ 33

22. SUPPLEMENTAL CASH FLOW DISCLOSURES

Year ended December 31	2019	2018
Cash provided by (used in):		
Trade receivables and other	**$ (173)**	$ 80
Inventories	**3**	(5)
Accounts payable and accrued liabilities	**30**	10
	$ (140)	$ 85
Changes in non-cash working capital relating to:		
Operating	**$ (110)**	$ 111
Investing	**(30)**	(26)
	$ (140)	$ 85
Cash and cash equivalents:[a]		
Cash	**$ 206**	$ 277
Cash equivalents	**—**	41
	$ 206	$ 318
Cash interest paid	**$ 239**	$ 252

a. As at December 31, 2019, $135 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (December 31, 2018 – $154 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$1.2965 (December 31, 2018 – US $1 = C$1.3646).

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, 2017	$ —	$ —	$ 4,684
Cash changes:			
Payments on lease liabilities	—	(12)	—
Repayment of long-term debt	—	—	(1,285)
Non-cash changes:			
Lease liabilities incurred	—	130	—
Interest expense on lease liabilities	—	13	—
Unrealized (gain) loss on foreign exchange	—	—	346
Amortization of deferred debt discount and debt issue costs	—	—	5
Other	—	—	7
Balance as at December 31, 2018	$ —	$ 131	$ 3,757
Cash changes:			
Receipts on leased assets	(1)	—	—
Payments on lease liabilities	—	(45)	—
Repayment of long-term debt	—	—	(297)
Repurchase of senior secured second lien notes	—	—	(204)
Non-cash changes:			
IFRS 16 opening balance sheet adjustment	19	160	—
Lease liabilities incurred	—	13	—
Lease liabilities modified	—	(4)	—
Interest expense on lease liabilities	—	26	—
Unrealized (gain) loss on foreign exchange	—	—	(180)
Amortization of deferred debt discount and debt issue costs	—	—	17
Debt redemption premium	—	—	29
Other	—	—	1
Balance as at December 31, 2019	**$ 18**	**$ 281**	**$ 3,123**

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

23. NET EARNINGS (LOSS) PER COMMON SHARE

Year ended December 31	**2019**	**2018**
Net loss	**$ (62)**	$ (119)
Weighted average common shares outstanding (millions)[(a)]	**299**	296
Dilutive effect of stock options, RSUs and PSUs (millions)[(b)]	**—**	—
Weighted average common shares outstanding – diluted (millions)	**299**	296
Net loss per share, basic	**$ (0.21)**	$ (0.40)
Net loss per share, diluted	**$ (0.21)**	$ (0.40)

a. Weighted average common shares outstanding for the year ended December 31, 2019 includes 381,014 PSUs not yet released (year ended December 31, 2018 - nil).

b. For the year ended December 31, 2019, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss. If the Corporation had recognized net earnings for the year ended December 31, 2019, the dilutive effect of stock options, RSUs and PSUs would have been three million weighted average common shares (year ended December 31, 2018 - four million weighted average common shares).

24. 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, commodity risk management contracts, accounts payable and accrued liabilities, derivative financial liabilities included within provisions and other liabilities, and long-term debt.

a. Fair values:

The carrying value of cash and cash equivalents, trade receivables and other and accounts payable and accrued liabilities 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	December 31, 2019		December 31, 2018	
	Carrying amount	**Fair value**	**Carrying amount**	**Fair value**
Recurring measurements:				
Financial assets				
Commodity risk management contracts	$ —	$ —	$ 123	$ 123
Financial liabilities				
Long-term debt[(i)] (Note 10)	$ **3,107**	$ **3,160**	$ 3,787	$ 3,707
Derivative financial liabilities	$ —	$ —	$ 1	$ 1
Commodity risk management contracts	$ **77**	$ **77**	$ 30	$ 30

(i) Includes the current and non-current portions.

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker.

The fair value of commodity risk management contracts and derivative financial liabilities are 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. Commodity price risk management:

The Corporation enters into derivative financial instruments to manage commodity price risk. The use of the financial commodity 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 commodity 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 December 31, 2019:

As at December 31, 2019	Volumes (bbls/d)[(i)]	Term	Average Price (US$/bbl)[(i)]
Crude Oil Sales Contracts			
WTI[(ii)] Fixed Price	34,475	Jan 1, 2020 - Dec 31, 2020	$58.75
WTI:WCS[(iii)] Fixed Differential	17,503	Jan 1, 2020 - Dec 31, 2020	$(22.06)
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	Jan 1, 2020 - Dec 31, 2020	$(7.63)
WTI:Mont Belvieu Fixed Differential	8,250	Jan 1, 2021 - Dec 31, 2021	$(10.38)
WTI:Mont Belvieu Fixed % of WTI	7,750	Jan 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 commodity risk management positions:

As at	December 31, 2019			December 31, 2018		
	Asset	Liability	Net	Asset	Liability	Net
Gross amount	$ —	$ (77)	$ (77)	$ 303	$ (66)	$ 237
Amount offset	—	—	—	(180)	36	(144)
Net amount	$ —	$ (77)	$ (77)	$ 123	$ (30)	$ 93
Current portion	$ —	$ (77)	$ (77)	$ 123	$ (6)	$ 117
Non-current portion	—	—	—	—	(24)	(24)
Net amount	$ —	$ (77)	$ (77)	$ 123	$ (30)	$ 93

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

As at December 31	2019	2018
Fair value of contracts, beginning of year	$ 93	$ (69)
Fair value of contracts realized	112	139
Change in fair value of contracts	(282)	23
Amortized premiums on put options	—	—
Fair value of contracts, end of period	**$ (77)**	$ 93

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

Year Ended December 31	2019	2018
Realized loss (gain) on commodity risk management	**$ 113**	$ 139
Unrealized loss (gain) on commodity risk management	**169**	(161)
Commodity risk management loss (gain)	**$ 282**	$ (22)

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 December 31, 2019:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$1.00 per bbl applied to WTI contracts	**$ (20)**	**$ 20**
Crude oil differential price [(i)]	± US$1.00 per bbl applied to WTI:WCS differential contracts	**$ 8**	**$ (8)**

(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 December 31, 2019. As a result, these contracts are not reflected in the Corporation's Consolidated Financial Statements:

Subsequent to December 31, 2019	Volumes (bbls/d)[(i)]	Term	Average Prices (US$/bbl)[(i)]
Crude Oil Sales Contracts			
WTI Fixed Price	9,834	Jan 1, 2020 - Oct 31, 2020	$61.01
WTI:WCS Fixed Differential	7,975	Apr 1, 2020 - Dec 31, 2020	$(15.71)
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	2,700	Jan 1, 2021 - Dec 31, 2021	$(10.34)
WTI:Mont Belvieu Fixed Differential	200	Jan 1, 2022 - Dec 31, 2022	$(11.30)

(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. 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 December 31, 2019, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $377 million.

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 December 31, 2019 was $206 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 $206 million.

d. Foreign currency risk management:

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the fair value or future cash flows of the Corporation's financial assets or liabilities. The Corporation has U.S. dollar denominated long-term debt as described in Note 10. As at December 31, 2019, a $0.01 change in the U.S. dollar to Canadian dollar exchange rate would have resulted in a change to the carrying value of long-term debt and a corresponding change to earnings (loss) before income tax of C$24 million (December 31, 2018 - C$28 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.

The future undiscounted financial obligations of the Corporation are noted below:

As at December 31, 2019	**Total**	**Less than 1 year**	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Long-term debt[(i)]	$ 3,107	$ —	$ 1,037	$ 1,297	$ 773
Interest on long-term debt	$ 845	207	561	73	4
Commodity risk management contracts	$ 77	77	—	—	—
Accounts payable and accrued liabilities	$ 379	379	—	—	—
	$ 4,408	$ 663	$ 1,598	$ 1,370	$ 777

(i) These debt maturities do not reflect the refinancing associated with the US$1.2B private offering which closed on January 31, 2020. Please refer to Note 10(e) for further details.

As at December 31, 2018	**Total**	**Less than 1 year**	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Long-term debt	$ 3,787	$ 17	$ 34	$ 1,349	$ 2,388
Interest on long-term debt	1,267	249	496	427	96
Commodity risk management contracts	93	117	(24)	—	—
Derivative financial liabilities	1	—	—	1	—
Accounts payable and accrued liabilities	343	343	—	—	—
	$ 5,492	$ 726	$ 506	$ 1,776	$ 2,484

25. GEOGRAPHICAL DISCLOSURE

As at December 31, 2019, the Corporation had non-current assets related to operations in the United States of $102 million (December 31, 2018 – $99 million). For the year ended December 31, 2019, petroleum revenue related to operations in the United States was $1.8 billion (year ended December 31, 2018 – $1.2 billion).

26. 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 it has sufficient capital resources to allow the Corporation to meet its liquidity requirements for the forseeable future. Debt repayment and sustaining capital expenditure activities are anticipated to be funded by the Corporation's adjusted funds flow and cash on hand.

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. The Corporation has an $800 million undrawn revolving credit facility, as well as a $500 million letter of credit facility, guaranteed by Export Development Canada, of which $99 million is undrawn.

The following table summarizes the Corporation's net debt:

As at December 31	Note		2019		2018
Non-current portion of long-term debt	10	**$**	**3,123**	$	3,740
Current portion of long-term debt	10		**—**		17
Cash and cash equivalents			**(206)**		(318)
Net debt		**$**	**2,917**	$	3,439

Net debt is an important measure used by management to analyze leverage and liquidity. Net debt decreased to $2.9 billion at December 31, 2019 from $3.4 billion at December 31, 2018. The decrease is mainly due to the senior secured term loan repayments of $297 million (US$225 million) and $204 million (US$154 million) repurchase and extinguishment of a portion of the 6.5% senior secured second lien notes during the year ended December 31, 2019.

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

Year ended December 31	Note		2019		2018
Net cash provided by (used in) operating activities		**$**	**631**	$	280
Net change in non-cash operating working capital items			**110**		(111)
Funds flow from (used in) operations			**741**		169
Adjustments:					
Other income	20		**(20)**		—
Decommissioning expenditures	11		**2**		5
Net change in other liabilities(i)			**3**		3
Realized gain on foreign exchange derivatives(ii)	17		**—**		(35)
Defense costs related to unsolicited bid(iii)	19		**—**		19
Payments on onerous contracts	11		**—**		19
Adjusted funds flow		**$**	**726**	$	180

(i) Excludes change in long-term cash-settled stock-based compensation liability.

(ii) A gain related to the settlement of forward currency contracts to manage the foreign exchange risk on Canadian dollar denominated proceeds related to the sale of assets designated for U.S. dollar denominated long-term debt repayment.

(iii) The Corporation incurred costs of $19 million in the fourth quarter of 2018 related to Husky Energy Inc.'s unsolicited bid to acquire all of the outstanding shares of the Corporation.

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.

27. 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 December 31, 2019:

	2020	2021	2022	2023	2024	Thereafter	Total
Transportation and storage[(i)]	$ 371	$ 424	$ 421	$ 455	$ 441	$ 5,956	$ 8,068
Diluent purchases	274	21	21	17	—	—	333
Other operating commitments	15	11	10	10	10	42	98
Variable office lease costs	5	5	5	5	5	33	58
Capital commitments	4	—	—	—	—	—	4
Commitments	**$ 669**	**$ 461**	**$ 457**	**$ 487**	**$ 456**	**$ 6,031**	**$ 8,561**

(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 11(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.

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