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.

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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

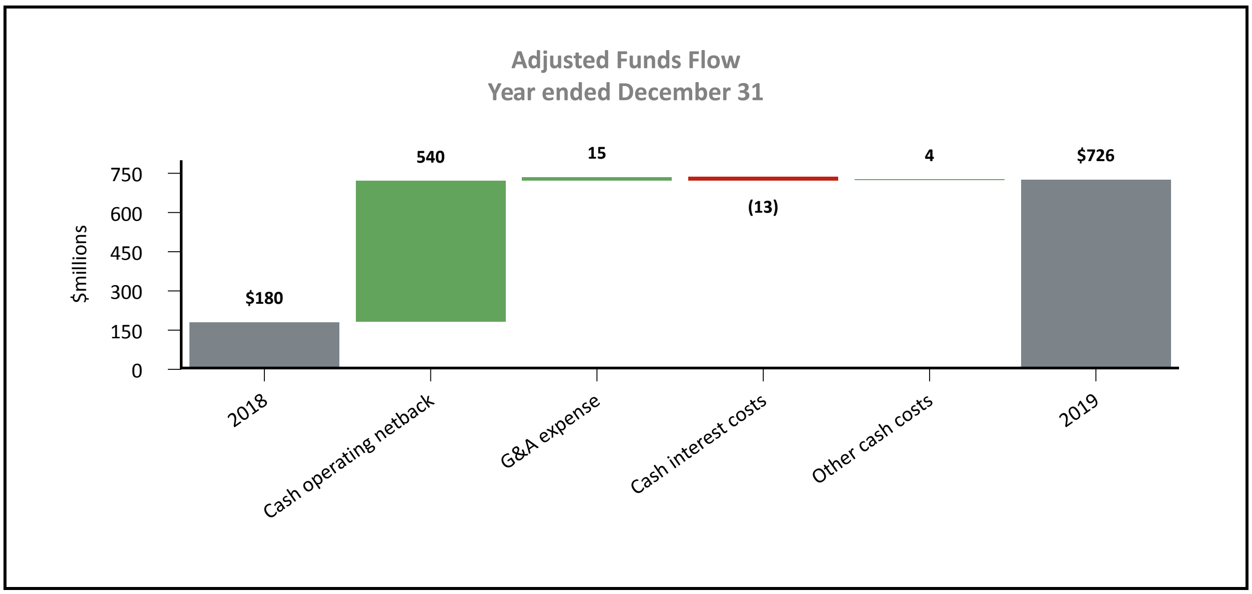
(1) *During the fourth quarter of 2019, the Corporation agreed to relieve the Alberta Petroleum Marketing Commission ("APMC") of all obligations pursuant to a crude oil purchase and sale agreement in exchange for a payment of $20 million.*

(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.



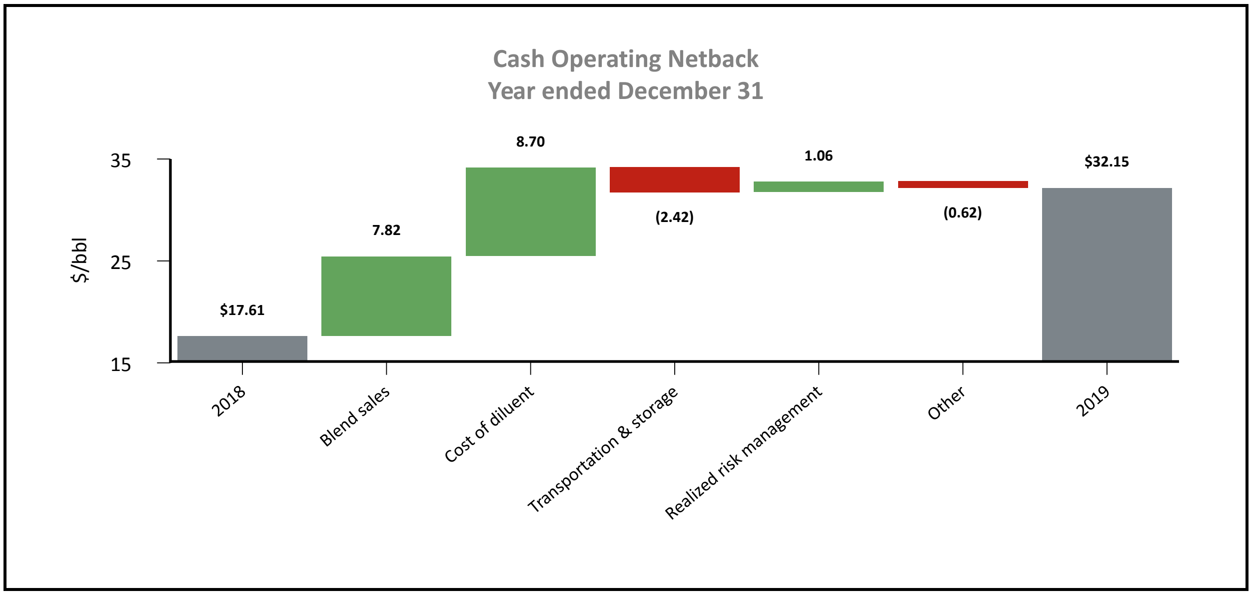
Cash Operating Netback

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.*