MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three and six months ended June 30, 2020 was approved by the Corporation's Audit Committee on July 27, 2020. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three and six months ended June 30, 2020, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2019, the 2019 annual MD&A and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in millions of Canadian dollars, except where otherwise indicated.

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

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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 its thermal oil production to refiners throughout North America and internationally.

MEG owns a 100% working interest in over 700 square miles of mineral leases. In the report prepared by GLJ Petroleum Consultants Ltd. ("GLJ") and effective December 31, 2019, GLJ estimated that the leases it had evaluated contained approximately 2.1 billion barrels of gross proved plus probable ("2P") bitumen reserves at the Christina Lake Project. For information regarding MEG's estimated reserves contained in the report prepared by GLJ, please refer to the Corporation’s most recently filed AIF, which is available on the Corporation’s website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

Beginning in early March 2020 and continuing into the second quarter of 2020, market conditions precipitated by the COVID-19 global pandemic ("COVID-19"), and subsequent measures intended to limit the outbreak globally, contributed to an unprecedented impact on global commodity prices. With reduced crude oil demand and excess supply, the price of crude oil and other petroleum products deteriorated significantly during the first half of 2020 and although there has been an improvement in the stability of the global oil market near the end of June and into July, there remains uncertainty regarding the ongoing impact of COVID-19 on global commodity prices.

The Corporation is continually monitoring and responding to the evolving COVID-19 situation. The Corporation’s business activities have been declared an essential service by the Alberta Government and the Corporation remains committed to the health and safety of all personnel and to the safety and continuity of operations. The health and safety measures implemented by the Corporation's COVID-19 task force during the first quarter of 2020 currently remain in place. The vast majority of office staff are still working remotely; however, beginning in June the Corporation lifted certain restrictions which allowed more location essential personnel to be present at the Christina Lake site to facilitate planned turnaround activities while still maintaining COVID-19 related screening, procedures and protocols to ensure continued safe and reliable operations.

Bitumen production averaged 75,687 bbls/d during the second quarter of 2020 compared to 97,288 bbls/d in the second quarter of 2019. The decrease in average bitumen production was primarily driven by major planned turnaround activities at the Phase 1 and 2 facilities, which began in early June 2020, decreasing production by approximately 10,000 bpd in the second quarter of 2020 as well as voluntary price-related production curtailments in April and May 2020. The major planned turnaround is expected to be complete in August 2020.

Realized commodity risk management gains of $215 million in the second quarter of 2020 partially offset the impact of deteriorating commodity prices and decreased production levels. The Corporation generated adjusted funds flow of $89 million in the second quarter of 2020 compared to $227 million in the second quarter of 2019.

The Corporation recognized a net loss of $80 million in the second quarter of 2020 compared to a net loss of $64 million in the second quarter of 2019. The increase in the net loss is due to the decreased cash operating netback as well as an unrealized loss on commodity risk management contracts of $267 million. Comparatively, the net loss in the second quarter of 2019 reflects a $237 million accelerated depreciation expense.

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:

	Six months ended June 30		2020		2019				2018	
($millions, except as indicated)	2020	2019	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Bitumen production - bbls/d	83,622	92,228	75,687	91,557	94,566	93,278	97,288	87,113	87,582	98,751
Steam-oil ratio	2.31	2.18	2.32	2.31	2.27	2.26	2.16	2.20	2.22	2.17
Bitumen sales - bbls/d	83,806	92,486	70,397	97,214	94,347	94,992	95,120	89,822	88,283	93,856
Bitumen realization - $/bbl	15.56	56.42	10.18	19.45	46.86	53.37	62.23	50.21	15.31	49.63
Net operating costs - $/bbl(1)	5.78	5.39	6.14	5.51	5.87	4.30	4.66	6.17	4.55	4.34
Non-energy operating costs - $/bbl	4.37	4.86	4.09	4.57	4.49	4.22	4.53	5.22	4.25	4.38
Cash operating netback - $/bbl(2)	20.62	33.98	25.84	16.83	28.33	32.44	37.88	29.80	7.14	24.01
Adjusted funds flow(3)	166	378	89	78	157	192	227	151	(37)	116
Per share, diluted	0.55	1.26	0.29	0.26	0.51	0.63	0.76	0.50	(0.13)	0.39
Revenue	972	1,980	307	665	992	958	1,062	919	520	803
Net earnings (loss)	(364)	(111)	(80)	(284)	26	24	(64)	(48)	(199)	118
Per share, diluted	(1.21)	(0.37)	(0.26)	(0.95)	0.09	0.08	(0.21)	(0.16)	(0.67)	0.39
Capital expenditures	74	85	20	54	72	40	32	53	144	139
Cash and cash equivalents	120	399	120	62	206	154	399	154	318	373
Long-term debt - C$	3,096	3,582	3,096	3,212	3,123	3,257	3,582	3,660	3,740	3,544
Long-term debt - US$	2,274	2,737	2,274	2,275	2,409	2,459	2,737	2,740	2,741	2,742

(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 20 of the interim consolidated financial statements for further details.*

3. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended June 30		Six months ended June 30	
	2020	2019	2020	2019
Bitumen production – bbls/d	**75,687**	97,288	**83,622**	92,228
Steam-oil ratio (SOR)	**2.32**	2.16	**2.31**	2.18

Bitumen Production

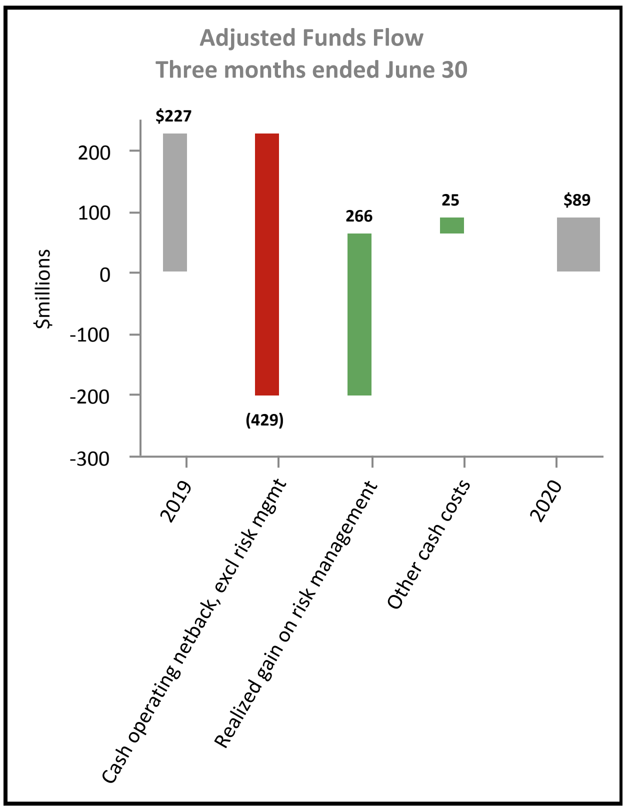
Bitumen production averaged 75,687 bbls/d and 83,622 bbls/d during the three and six months ended June 30, 2020, compared to 97,288 bbls/d and 92,228 bbls/d during the same periods of 2019. The decrease in average bitumen production was primarily driven by major planned turnaround activities at the Phase 1 and 2 facilities, which began in early June 2020, decreasing production by approximately 10,000 bbls/d during the three months ended June 30, 2020 as well as voluntary price-related production curtailments in April and May 2020. The major planned turnaround is expected to be complete in August 2020.

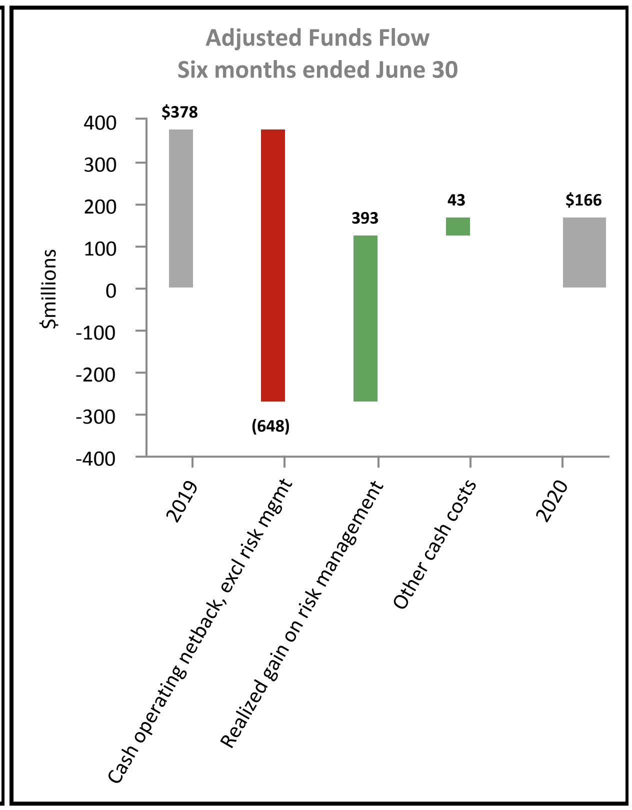
Steam-Oil Ratio

The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is Steam-Oil Ratio ("SOR"), which is an efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The Corporation continues to focus on improving efficiency of production through a lower SOR, which generally indicates that steam is being more efficiently used, but is also influenced by the introduction of new wells into circulation. The SOR increased for the three and six months ended June 30, 2020, compared to the same periods of 2019, due to the timing of new well pairs and wells being brought into steam circulation and production, as well as reduced production levels due to COVID-19 and plant turnaround activities.

Adjusted Funds Flow

During the three and six months ended June 30, 2020, adjusted funds flow decreased compared to the same periods of 2019, primarily driven by the Corporation's reduced cash operating netback which was significantly impacted by a sharp decline in global crude oil prices, partially offset by realized gains on commodity risk management contracts. The decrease in adjusted funds flow was also partially mitigated by ongoing cost reductions to general and administrative expense and cash interest costs.





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

	Three months ended June 30		Six months ended June 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Net cash provided by (used in) operating activities	**$ 117**	$ 302	**$ 216**	$ 233
Net change in non-cash operating working capital items	**(48)**	(75)	**(78)**	145
Funds flow from (used in) operations	**69**	227	**138**	378
Adjustments:				
Contract cancellation[(1)]	**20**	—	**26**	—
Decommissioning expenditures	**—**	—	**2**	—
Adjusted funds flow	**$ 89**	$ 227	**$ 166**	$ 378

(1) Costs incurred to mitigate rail sales contract exposure. Contract cancellation costs or recoveries are excluded from adjusted funds flow as they are not considered part of ordinary continuing operating results.

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.

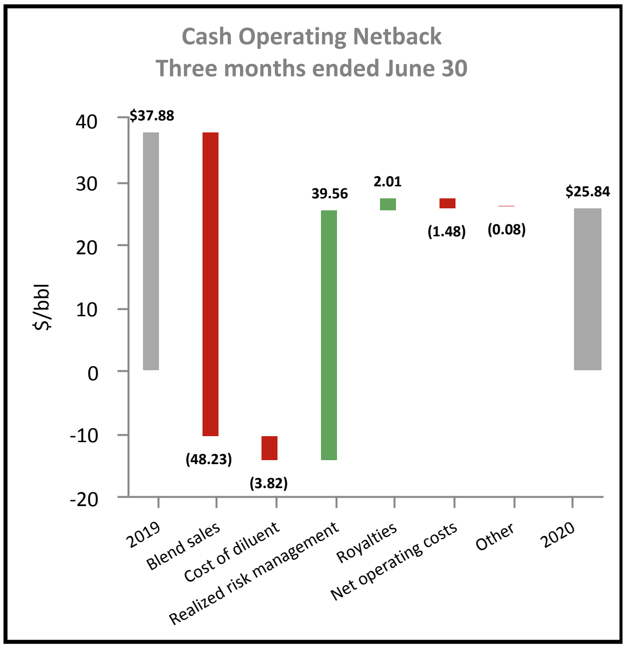
Cash Operating Netback

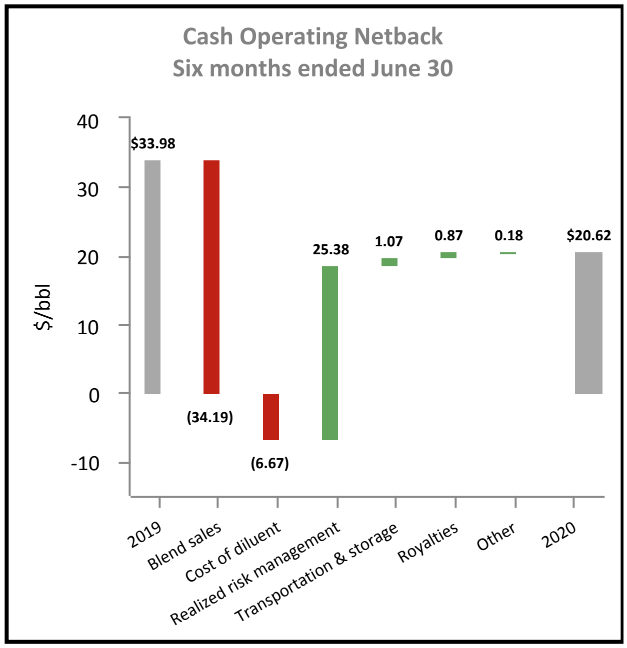
The following table summarizes the Corporation's cash operating netback. Unless otherwise indicated, the per barrel calculation for the periods indicated below are based on bitumen sales volume.

	Three months ended June 30				Six months ended June 30			
	2020		**2019**		**2020**		**2019**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Sales from production	**$ 181**		$ 863		**$ 650**		$ 1,559	
Sales from purchased product[(1)]	**118**		199		**297**		402	
Petroleum revenue	**299**		1,062		**947**		1,961	
Purchased product	**(106)**		(199)		**(282)**		(394)	
Blend sales[(2)]	**$ 193**	**$ 20.96**	$ 863	$ 69.19	**$ 665**	**$ 30.03**	$ 1,567	$ 64.22
Cost of diluent	**(128)**	**(10.78)**	(325)	(6.96)	**(428)**	**(14.47)**	(622)	(7.80)
Bitumen realization	**65**	**10.18**	538	62.23	**237**	**15.56**	945	56.42
Transportation and storage[(3)]	**(75)**	**(11.77)**	(93)	(10.80)	**(152)**	**(9.96)**	(185)	(11.03)
Third-party curtailment credits[(4)]	—	—	(8)	(0.89)	**2**	**0.11**	(8)	(0.46)
Royalties	—	**(0.05)**	(18)	(2.06)	**(6)**	**(0.37)**	(21)	(1.24)
Net operating costs	**(40)**	**(6.14)**	(40)	(4.66)	**(88)**	**(5.78)**	(90)	(5.39)
Cash operating netback - excluding realized commodity risk management	**(50)**	**(7.78)**	379	43.82	**(7)**	**(0.44)**	641	38.30
Realized gain (loss) on commodity risk management	**215**	**33.62**	(51)	(5.94)	**321**	**21.06**	(72)	(4.32)
Cash operating netback[(5)]	**$ 165**	**$ 25.84**	$ 328	$ 37.88	**$ 314**	**$ 20.62**	$ 569	$ 33.98
Bitumen sales volumes - bbls/d		**70,397**		95,120		**83,806**		92,486

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

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





Bitumen Realization

Bitumen realization represents the Corporation's blend sales net of cost of diluent, expressed on a per barrel of bitumen sold 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 which is impacted by seasonality and pipeline specifications, the cost of transporting diluent to the production site from both Edmonton and U.S. Gulf Coast ("USGC") markets, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar. A portion of the cost of diluent is effectively recovered in the sales price of the blended product. Bitumen realization per barrel fluctuates primarily based on average benchmark prices and light:heavy oil differentials.

	Three months ended June 30				Six months ended June 30			
	2020		2019		2020		2019	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Sales from production	**$ 181**		$ 863		**$ 650**		$ 1,559	
Sales from purchased product[1]	**118**		199		**297**		402	
Petroleum revenue	**$ 299**		$ 1,062		**$ 947**		$ 1,961	
Purchased product	**(106)**		(199)		**(282)**		(394)	
Blend sales[2]	**$ 193**	**$ 20.96**	$ 863	$ 69.19	**$ 665**	**$ 30.03**	$ 1,567	$ 64.22
Cost of diluent	**(128)**	**(10.78)**	(325)	(6.96)	**(428)**	**(14.47)**	(622)	(7.80)
Bitumen realization	**$ 65**	**$ 10.18**	$ 538	$ 62.23	**$ 237**	**$ 15.56**	$ 945	$ 56.42

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

The blend sales price decreased by $48.23 per barrel, or 70%, during the three months ended June 30, 2020 compared to the same period of 2019. During the six months ended June 30, 2020, the blend sales price decreased by $34.19 per barrel, or 54%, compared to the same period of 2019. The decrease in blend sales price during the three and six months ended June 30, 2020 is due to a lower WTI price and wider WTI:AWB differentials. The WTI price experienced a significant decline during the three and six months ended June 30, 2020, largely driven by unprecedented demand shock in the global oil markets due to COVID-19. The widening of the WTI:AWB differential at Edmonton reflected prevailing demand/supply fundamentals for heavy oil in Western Canada and egress constraints moving beyond western Canada.

The Corporation continues to execute on its strategy to partially mitigate the cost of unutilized transportation and storage assets. During the second quarter of 2020, these activities added $12 million to blend sales, or $1.24 per barrel, to the blend sales price. On a year-to-date basis, an additional $15 million was added to blend sales, or $0.65 per barrel to the blend sales price. The Corporation does not engage in speculative trading. The purchase and sale of third-party products requires the concurrent locking in of price risk pursuant to policies approved by the Corporation's Board of Directors which can be achieved either through the counterparty or through financial price risk management.

Cost of diluent increased by $3.82 per barrel, or 55%, during the three months ended June 30, 2020 compared to the same period of 2019. During the six months ended June 30, 2020, the cost of diluent increased by $6.67 per barrel, or 86%, compared to the same period of 2019. The increase during the three and six months ended June 30, 2020 reflects wider WTI:AWB differentials and the use of higher priced diluent from inventory resulting in a lower recovery of the cost of diluent through blend sales.

The above factors, combined with lower production and sales volumes during the three months ended June 30, 2020, decreased bitumen realization by $52.05 per barrel, or 84%, and $40.86 per barrel, or 73%, during the three and six months ended June 30, 2020, respectively, compared to the same periods of 2019.

Transportation and Storage

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

	Three months ended June 30				Six months ended June 30			
	2020		2019		2020		2019	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Transportation and storage	**$ (75)**	**$ (11.77)**	$ (93)	$ (10.80)	**$ (152)**	**$ (9.96)**	$ (185)	$ (11.03)

During the three and six months ended June 30, 2020, total transportation and storage costs decreased 19% and 18%, respectively, compared to the same periods of 2019. The decrease is primarily the result of decreased blend sales volumes transported by rail to the USGC market. Beginning in 2020, the Corporation suspended its contracted transport of blend sales by rail to the USGC in favour of increasing its blend sales freight on board ("FOB") at rail terminals at Edmonton. The Corporation no longer leases rail cars nor has contracted rail commitments beyond loading capacity of FOB sales at Edmonton.

Transportation and storage costs on a per barrel basis increased during the three months ended June 30, 2020, compared to the same period of 2019, as fixed costs were allocated over lower sales volumes. These fixed costs were offset by $1.24 per barrel through asset optimization activities recognized in blend sales.

Effective July 1, 2020, the Corporation has contracted for 100,000 barrels per day of blend transportation capacity on the Flanagan South and Seaway pipeline systems, providing pipeline transportation directly to the USGC refineries and export terminals. To the extent that capacity is underutilized, the Corporation will look to mitigate the associated costs through short-term third-party contracts.

Royalties

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

	Three months ended June 30				Six months ended June 30			
	2020		2019		2020		2019	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Royalties	**$ —**	**$ (0.05)**	$ (18)	$ (2.06)	**$ (6)**	**$ (0.37)**	$ (21)	$ (1.24)

The decrease in royalties for the three and six months ended June 30, 2020, compared to the same periods of 2019, is primarily the result of the decrease in the WTI benchmark price.

Net Operating Costs

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

	Three months ended June 30				Six months ended June 30			
	2020		2019		2020		2019	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Operating costs - non-energy	**$ (27)**	**$ (4.09)**	$ (39)	$ (4.53)	**$ (67)**	**$ (4.37)**	$ (81)	$ (4.86)
Operating costs - energy	**(19)**	**(3.00)**	(15)	(1.78)	**(47)**	**(3.09)**	(43)	(2.55)
Power revenue	**6**	**0.95**	14	1.65	**26**	**1.68**	34	2.02
Net operating costs	**$ (40)**	**$ (6.14)**	$ (40)	$ (4.66)	**$ (88)**	**$ (5.78)**	$ (90)	$ (5.39)
Average natural gas purchase price (C$/mcf)		**$ 2.11**		1.68		**$ 2.39**		$ 2.35
Average realized power sales price (C$/Mwh)		**$ 28.34**		55.33		**$ 51.67**		$ 63.32

Non-energy operating costs decreased for the three and six months ended June 30, 2020, compared to the same periods of 2019, primarily as a result of the temporary Canadian Emergency Wage Subsidy ("CEWS") program, salary rollbacks and reductions in staff and consulting costs. The provincial and federal governments have recognized the serious economic impacts of COVID-19 resulting in the collapse of oil prices and the impact on the oil and gas industry and have taken steps to provide various programs, such as CEWS. During the three months ended June 30, 2020, the Corporation was able to benefit from non-recurring cost reductions, including CEWS, which offset non-energy operating costs by approximately $4 million.

Net energy operating costs increased for the three and six months ended June 30, 2020, compared to the same periods of 2019, predominantly due to market driven energy and power prices. Total net operating costs for the three and six months ended June 30, 2020 were essentially flat compared to the same periods of 2019.

Realized Gain or Loss on Commodity Risk Management

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

	Three months ended June 30				**Six months ended June 30**			
	2020		**2019**		**2020**		**2019**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Realized gain (loss) on commodity risk management	**$ 215**	**$ 33.62**	$ (51)	$ (5.94)	**$ 321**	**$ 21.06**	$ (72)	$ (4.32)

Realized gains recognized on commodity risk management contracts have significantly increased during the three and six months ended June 30, 2020, compared to the same periods of 2019, due to the unprecedented decline in the WTI price compared to the WTI fixed price contracts in place. Realized losses were recognized during the three and six months ended June 30, 2019. Refer to the commodity risk management discussion within the “OTHER OPERATING RESULTS” section of this MD&A for further details.

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

	Three months ended June 30, 2020				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline[3]	Rail	TOTAL (US$/bbl)
WTI - benchmark	$ 27.85	$ 27.85	$ 27.85	$ —	$ 27.85
Differential - WTI:AWB at sales point	(17.15)	(26.01)	(3.37)	—	(12.73)
Blend sales price	10.70	1.84	24.48	—	15.12
Transportation and storage[1]	(2.08)	(13.53)	(11.66)	—	(5.92)
Transportation and storage from Christina Lake to Edmonton[2]	2.08	2.08	2.08	—	2.08
Blend sales price, net of transportation & storage at Edmonton	$ 10.70	$ (9.61)	$ 14.90	$ —	$ 11.28
Total blend sales - bbls/d	61,344	4,391	35,245	—	100,980
% of total sales	61 %	4 %	35 %	— %	100 %

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 10.11	$ 24.48	$ 14.37
Transportation and storage[1]	(2.84)	(11.66)	(8.82)
Transportation and storage from Christina Lake to Edmonton[2]	2.08	2.08	—
Blend sales price, net of transportation & storage at Edmonton	$ 9.35	$ 14.90	$ 5.55

	Three months ended June 30, 2019				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)
WTI - benchmark	$ 59.82	$ 59.82	$ 59.82	$ 59.82	$ 59.82
Differential - WTI:AWB at sales point	(13.29)	(10.87)	1.48	(0.78)	(8.10)
Blend sales price	46.53	48.95	61.30	59.04	51.72
Transportation and storage[1]	(1.65)	(3.86)	(10.28)	(26.02)	(5.60)
Transportation and storage from Christina Lake to Edmonton[2]	1.65	1.65	1.65	1.65	1.65
Blend sales price, net of transportation & storage at Edmonton	$ 46.53	$ 46.74	$ 52.67	$ 34.67	$ 47.77
Total blend sales - bbls/d	73,822	16,783	39,855	6,660	137,120
% of total sales	54 %	12 %	29 %	5 %	100 %

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 46.98	$ 60.97	$ 13.99
Transportation and storage[1]	(2.04)	(12.53)	(10.49)
Transportation and storage from Christina Lake to Edmonton[2]	1.65	1.65	—
Blend sales price, net of transportation & storage at Edmonton	$ 46.59	$ 50.09	$ 3.50

(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$11.77 per barrel for the three months ended June 30, 2020 compared to C$10.80 per barrel for the three months ended June 30, 2019.

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

(3) Sales from marketing asset optimization activities are recognized in the blend sales price and not as a recovery of transportation and storage costs for consistency with the financial statements. These activities contributed $12 million to blend revenue, or US $2.56 per barrel, to the blend sales price at the USGC. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC would be US$9.10 per barrel and the WTI:AWB differential at the USGC would be US$5.93 per barrel.

(4) Results are translated at the average foreign exchange rate of 1.3860 for the three months ended June 30, 2020 and 1.3376 for the three months ended June 30, 2019.

	Six months ended June 30, 2020				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline[3]	Rail	TOTAL (US$/bbl)
WTI - benchmark	$ 37.01	$ 37.01	$ 37.01	$ 37.01	$ 37.01
Differential - WTI:AWB at sales point	(19.84)	(15.81)	(4.78)	12.65	(15.02)
Blend sales price	17.17	21.20	32.23	49.66	21.99
Transportation and storage[1]	(1.93)	(4.90)	(11.34)	(24.73)	(5.02)
Transportation and storage from Christina Lake to Edmonton[2]	1.93	1.93	1.93	1.82	1.93
Blend sales price, net of transportation & storage at Edmonton	$ 17.17	$ 18.23	$ 22.82	$ 26.75	$ 18.90
Total blend sales - bbls/d	72,150	16,129	32,258	1,143	121,680
% of total sales	59 %	13 %	27 %	1 %	100 %

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 17.91	$ 32.83	$ 14.92
Transportation and storage[1]	(2.47)	(11.80)	(9.33)
Transportation and storage from Christina Lake to Edmonton[2]	1.93	1.93	—
Blend sales price, net of transportation & storage at Edmonton	$ 17.37	$ 22.96	$ 5.59

	Six months ended June 30, 2019				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)
WTI - benchmark	$ 57.36	$ 57.36	$ 57.36	$ 57.36	$ 57.36
Differential - WTI:AWB at sales point	(14.60)	(10.18)	1.19	(2.31)	(9.20)
Blend sales price	42.76	47.18	58.55	55.05	48.16
Transportation and storage[1]	(1.72)	(4.14)	(10.58)	(24.50)	(5.68)
Transportation and storage from Christina Lake to Edmonton[2]	1.72	1.72	1.72	1.72	1.72
Blend sales price, net of transportation & storage at Edmonton	$ 42.76	$ 44.76	$ 49.69	$ 32.27	$ 44.20
Total blend sales - bbls/d	77,269	13,459	36,434	7,600	134,762
% of total sales	57 %	10 %	27 %	6 %	100 %

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 43.41	$ 57.94	$ 14.53
Transportation and storage[1]	(2.11)	(12.98)	(10.87)
Transportation and storage from Christina Lake to Edmonton[2]	1.72	1.72	—
Blend sales price, net of transportation & storage at Edmonton	$ 43.02	$ 46.68	$ 3.66

(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$9.96 per barrel for the six months ended June 30, 2020 compared to C$11.03 per barrel for the six months ended June 30, 2019.

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

(3) Sales from marketing asset optimization activities are recognized in the blend sales price and not as a recovery of transportation and storage costs for consistency with the financial statements. These activities contributed $15 million to blend revenue, or US $1.80 per barrel, to the blend sales price at the USGC. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC would be US$9.54 per barrel and the WTI:AWB differential at the USGC would be US$6.58 per barrel.

(4) Results are translated at the average foreign exchange rate of 1.3653 for the six months ended June 30, 2020 and 1.3335 for the six months ended June 30, 2019.

The Corporation's access to the USGC, where sales pricing is not subject to the same light:heavy oil differential as at the Edmonton market, translated into premiums earned on AWB blend sales at the USGC over the Edmonton market of US$5.55 per barrel and US$5.59 per barrel for the three and six months ended June 30, 2020. This compares to premiums of US$3.50 per barrel and US$3.66 per barrel at the USGC compared to Edmonton market during the three and six months ended June 30, 2019. The premiums recognized during the three and six months ended June 30, 2020 were higher than the same periods of 2019 primarily due to the wider WTI:AWB differential at Edmonton and the suspension of USGC rail during the three and six months ended June 30, 2020. The Corporation actively manages its sales strategy to maximize benefits from location differentials when they arise.

Excluding transportation and storage costs upstream of the Edmonton market, the Corporation's net AWB blend sales price at Edmonton averaged US$11.28 per barrel during the three months ended June 30, 2020 compared to the posted AWB benchmark price at Edmonton of US$14.41 per barrel. This was largely a result of having greater sales exposure to the weaker priced months of April and May 2020 (approximately 110,000 bbls/d of AWB blend sales), with reduced volumes sold in the stronger priced month of June 2020 (approximately 84,000 bbls/d of AWB blend sales) due to the major planned turnaround that began in early June 2020.

Excluding transportation and storage costs upstream of the Edmonton market, the Corporation's AWB blend sales price averaged US$18.90 per barrel during the six months ended June 30, 2020 consistent with the posted AWB benchmark price at Edmonton of US$18.90 per barrel. Notwithstanding that Enbridge Mainline apportionment averaged 32% during the six months ended June 30, 2020, the Corporation was able to capture pricing inline with the Edmonton AWB benchmark price as a result of its marketing and storage assets and the ability to move barrels to the higher-priced USGC market.

Revenue

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

	Three months ended June 30		Six months ended June 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Sales from:				
Production	**$ 181**	$ 863	**$ 650**	$ 1,559
Purchased product[1]	**118**	199	**297**	402
Petroleum revenue	**$ 299**	$ 1,062	**$ 947**	$ 1,961
Royalties	**—**	(18)	**(6)**	(21)
Petroleum revenue, net of royalties	**$ 299**	$ 1,044	**$ 941**	$ 1,940
Power revenue	**$ 6**	$ 14	**$ 26**	$ 34
Transportation revenue	**2**	3	**5**	6
Other revenue	**$ 8**	$ 17	**$ 31**	$ 40
Total revenues	**$ 307**	$ 1,061	**$ 972**	$ 1,980

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

During the three and six months ended June 30, 2020, total revenues decreased 71% and 51%, respectively, from the same periods of 2019 primarily as a result of the decrease to the average blend sales price driven by the decline in WTI prices, the widening of WTI:AWB differentials and reduced blend sales volumes.

Net Loss

	Three months ended June 30		Six months ended June 30	
($millions, except per share amounts)	**2020**	**2019**	**2020**	**2019**
Net loss	**$ (80)**	$ (64)	**$ (364)**	$ (111)
Per share, diluted	**$ (0.26)**	$ (0.21)	**$ (1.21)**	$ (0.37)

The net loss for the three months ended June 30, 2020 reflects a lower cash operating netback compared to the same period of 2019 as well as an unrealized loss on commodity risk management contracts of $267 million and an unrealized gain on foreign exchange of $114 million. The net loss for the six months ended June 30, 2020 also reflects a lower cash operating netback compared to the same period of 2019 as well as an exploration expense of $366 million and an unrealized loss on foreign exchange of $153 million, partially offset by an unrealized gain on commodity risk management contracts of $161 million.

Comparatively, the net loss in the three months ended June 30, 2019 reflects an accelerated depreciation expense of $237 million and an exploration expense of $58 million, partially offset by unrealized gains on commodity risk management contracts and foreign exchange of $87 million and $67 million, respectively. The net loss in the six months ended June 30, 2019 also reflects the $237 million accelerated depreciation expense and an unrealized loss on commodity risk management contracts of $122 million, partially offset by an unrealized foreign exchange gain of $145 million.

Capital Expenditures

	Three months ended June 30		Six months ended June 30	
($millions)	**2020**	**2019**(1)	**2020**	**2019**(1)
Sustaining and maintenance	**$ 10**	$ 19	**$ 50**	$ 41
Turnaround	**10**	—	**10**	—
Phase 2B brownfield expansion	**—**	7	**14**	20
eMVAPEX	**—**	5	**—**	12
Field infrastructure, corporate and other	**—**	1	**—**	12
	$ 20	$ 32	**$ 74**	$ 85

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

The decrease in capital spending for the three and six months ended June 30, 2020, compared to the same periods of 2019, reflects the Corporation's decision to reduce capital spending in the first half of 2020 due to the economic instability created by COVID-19. Capital expenditures during the three and six months ended June 30, 2020 were primarily directed towards sustaining and maintenance activities including the turnaround that began in early June 2020. Phase 2B brownfield expansion expenditures are currently suspended until project economics improve.

4. OUTLOOK

On May 4, 2020, the Corporation suspended full year 2020 production guidance due to the global crude oil price environment at that time which was experiencing multi-decade lows coupled with extreme levels of volatility driven by the unprecedented demand shock due to COVID-19.

Since that time, crude oil price levels and volatility have stabilized to a level that allows the Corporation to re-instate full year production guidance which is now targeted at 78,000 – 80,000 bbls/d. Compared to the original guidance of 94,000 – 97,000 bbls/d announced November 21, 2019, approximately half of the difference is due to the impact of the scheduled 70-day major turnaround at the Christina Lake Phase 1 and 2 facilities announced May 4, 2020. The remainder of the difference results from a combination of previously disclosed weather-related production impacts in the first quarter of 2020, voluntary price-related production curtailments in the second quarter of 2020 and the impact of reduced well capital in 2020, which made up approximately 75% of the combined $100 million reduction in capital spending announced on March 10 and May 4 of 2020.

Guidance for non-energy operating costs, general and administrative expense ("G&A") and capital expenditures remains unchanged from the revised guidance announced May 4, 2020.

Summary of 2020 Guidance	
Production (full year 2020 average)	78,000 - 80,000 bbls/d
Non-energy operating cost	$140 - $150 million
G&A expense	$52.5 - $55 million
Capital expenditures	$150 million

5. BUSINESS ENVIRONMENT

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

	Six months ended June 30		2020		2019			
	2020	2019	Q2	Q1	Q4	Q3	Q2	Q1
Average Benchmark Commodity Prices								
Crude oil prices								
Brent (US$/bbl)	**42.13**	66.11	**33.30**	50.95	62.50	61.97	68.32	63.90
WTI (US$/bbl)	**37.01**	57.36	**27.85**	46.17	56.96	56.45	59.82	54.90
Differential – WTI:WCS – Edmonton (US$/bbl)	**(16.00)**	(11.48)	**(11.47)**	(20.53)	(15.83)	(12.24)	(10.67)	(12.29)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(18.11)**	(13.42)	**(13.44)**	(22.78)	(18.44)	(14.52)	(12.32)	(14.50)
AWB – Edmonton (US$/bbl)	**18.90**	43.94	**14.41**	23.39	38.52	41.93	47.50	40.40
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(6.52)**	0.38	**(7.29)**	(5.74)	(5.25)	(2.50)	1.64	(0.89)
AWB – U.S. Gulf Coast (US$/bbl)	**30.49**	57.74	**20.56**	40.43	51.71	53.95	61.46	54.01
Condensate prices								
Condensate at Edmonton (C$/bbl)	**46.24**	71.00	**30.72**	61.76	70.01	68.73	74.76	67.25
Condensate at Edmonton as % of WTI	**91.5%**	92.8%	**79.6%**	99.5%	93.1%	92.2%	93.4%	92.1%
Condensate at Mont Belvieu, Texas (US$/bbl)	**28.35**	49.27	**17.43**	39.27	50.08	44.34	50.22	48.31
Condensate at Mont Belvieu, Texas as % of WTI	**76.6%**	85.9%	**62.6%**	85.1%	87.9%	78.5%	84.0%	88.0%
Natural gas prices								
AECO (C$/mcf)	**2.23**	1.99	**2.21**	2.26	2.70	0.95	1.12	2.86
Electric power prices								
Alberta power pool (C$/MWh)	**48.16**	63.55	**29.94**	66.38	47.07	46.95	56.37	70.73
Foreign exchange rates								
C$ equivalent of 1 US$ – average	**1.3653**	1.3335	**1.3860**	1.3445	1.3201	1.3207	1.3376	1.3293
C$ equivalent of 1 US$ – period end	**1.3616**	1.3091	**1.3616**	1.4120	1.2965	1.3244	1.3091	1.3360

Beginning in early March 2020 and continuing into the second quarter of 2020, market conditions precipitated by COVID-19, and subsequent measures intended to limit the outbreak globally, contributed to an unprecedented impact on global commodity prices. With reduced crude oil demand and excess supply, the price of crude oil and other petroleum products deteriorated significantly during the first half of 2020 and although there has been an improvement in the stability of the global oil market near the end of June and into July, there remains uncertainty regarding the ongoing impact of COVID-19 on global commodity prices.

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

Crude Oil Prices

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

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

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

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

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

Condensate Prices

In order to facilitate pipeline transportation of bitumen, the Corporation uses condensate as diluent for blending with the Corporation’s bitumen. The Corporation sources its condensate from the Edmonton area, but due to high demand for condensate in the Edmonton market, the Corporation also purchases condensate from the USGC market where pricing is generally lower. The Corporation's committed diluent purchases at the USGC reference benchmark pricing at Mont Belvieu, Texas. The Corporation's per barrel cost of condensate sourced from Mont Belvieu, Texas included net transportation costs of approximately US$6.16 per barrel and US$6.13 per barrel to move the product from Mont Belvieu to the Edmonton area for the three and six months ended June 30, 2020, respectively.

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 three and six months ended June 30, 2020 compared to the same periods of 2019 due to low gas storage inventories.

Electric Power Prices

Electric power prices impact the price that the Corporation receives on the sale of surplus power from the Corporation’s cogeneration facilities. The Alberta power pool price decreased during the three and six months ended June 30, 2020 compared to the same periods of 2019 primarily as a result of an oversupply of generation in the province.

6. OTHER OPERATING RESULTS

Depletion and Depreciation

		Three months ended June 30		Six months ended June 30
($millions)	**2020**	2019	**2020**	2019
Depletion and depreciation expense	**$ 93**	$ 365	**$ 217**	$ 480
Depletion and depreciation expense per barrel of production	**$ 13.55**	$ 41.22	**$ 14.25**	$ 28.76

Depletion and depreciation expense was impacted by one-time charges as the Corporation narrows its development focus to core assets at Christina Lake. The Corporation incurred an accelerated depreciation expense of $13 million, or $0.86 per barrel, during the six months ended June 30, 2020 compared to $237 million, or $14.20 per barrel, for the six months ended June 30, 2019. The accelerated depreciation expense in 2019 was recognized on equipment, materials and engineering costs associated with greenfield expansion projects and a partial upgrading technology project.

Excluding one-time charges, depletion and depreciation expense was $13.55 per barrel and $13.39 per barrel for the three and six months ended June 30, 2020, respectively, compared to $14.44 per barrel and $14.56 per barrel for the three and six months ended June 30, 2019.

Exploration Expense

		Three months ended June 30		Six months ended June 30
($millions)	**2020**	2019	**2020**	2019
Exploration expense	**$ —**	58	**$ 366**	58

During the first quarter of 2020, the Corporation discontinued exploration and evaluation activities in certain non-core growth properties and as such the associated land lease and evaluation costs totaling $366 million were charged to exploration expense during the six months ended June 30, 2020 compared to $58 million during the same period of 2019. This is a result of focusing on the development of core assets to manage the business through an unpredictable global downturn of unknown duration.

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.

	Three months ended June 30		Six months ended June 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Realized:				
Crude oil contracts[1]	**$ 226**	$ (44)	**$ 335**	$ (62)
Condensate contracts[2]	**(11)**	(7)	**(14)**	(10)
Realized commodity risk management gain (loss)	**$ 215**	$ (51)	**$ 321**	$ (72)
Unrealized:				
Crude oil contracts[1]	**$ (323)**	$ 91	**$ 117**	$ (112)
Condensate contracts[2]	**56**	(4)	**44**	(10)
Unrealized commodity risk management gain (loss)	**$ (267)**	$ 87	**$ 161**	$ (122)
Commodity risk management gain (loss)	**$ (52)**	$ 36	**$ 482**	$ (194)

(1) Includes WTI fixed price contracts, WTI options, WTI:WCS fixed differential contracts and WTI:WCS (USGC) fixed differential contracts.

(2) Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas relative to WTI.

During the three months ended June 30, 2020, a $215 million commodity risk management gain was realized on settled commodity risk management contracts significantly insulating the Corporation's cash operating netback from the volatile commodity market, particularly crude oil prices. The fair value of commodity risk management contracts which settle in future periods was reduced as forward prices had improved at the end of the second quarter of 2020, compared to forward prices at the end of the first quarter of 2020. Forward WTI prices increased and WTI:WCS differentials narrowed relative to contracted prices resulting in a $267 million unrealized commodity risk management loss during the second quarter of 2020.

For the six months ended June 30, 2020, the Corporation recognized a $482 million net gain from commodity risk management primarily due to weakening WTI prices relative to contracted prices. This compares with the $194 million net loss from commodity risk management for the six months ended June 30, 2019, when WTI prices increased and WTI:WCS differentials narrowed relative to contracted prices.

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 gain (loss):

	Three months ended June 30		Six months ended June 30	
(US$/bbl)	**2020**	**2019**	**2020**	**2019**
WTI fixed price contracts:				
Average fixed price	**$ 56.75**	$ 63.96	**$ 57.74**	$ 64.14
Average settlement price	**27.85**	60.17	**37.01**	57.53
Gain (loss) on WTI fixed price contracts	**$ 28.90**	$ 3.79	**$ 20.73**	$ 6.61
WTI:WCS fixed differential contracts:				
Average fixed differential	**$ (18.67)**	$ (21.82)	**$ (19.85)**	$ (22.48)
Average settlement differential	**(11.47)**	(10.68)	**(16.00)**	(11.49)
Gain (loss) on WTI:WCS fixed differential contracts	**$ (7.20)**	$ (11.14)	**$ (3.85)**	$ (10.99)
Condensate purchase contracts:				
Average fixed differential[1]	**$ (5.81)**	$ (5.66)	**$ (5.59)**	$ (5.11)
Average settlement differential	**(10.47)**	(9.59)	**(8.69)**	(8.09)
Gain (loss) on condensate purchase contracts	**$ (4.66)**	$ (3.93)	**$ (3.10)**	$ (2.98)

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

General and Administrative

	Three months ended June 30		Six months ended June 30	
($millions)	**2020**	**2019**	**2020**	**2019**
General and administrative expense	**$ 9**	$ 16	**$ 25**	$ 34
General and administrative expense per barrel of production	**$ 1.29**	$ 1.81	**$ 1.66**	$ 2.03

General and administrative expense decreased 44% and 26% for the three and six months ended June 30, 2020, respectively, compared to the same periods of 2019, primarily as a result of the temporary CEWS, salary rollbacks and reductions in staff and consulting costs. During the three months ended June 30, 2020, the Corporation was able to benefit from non-recurring cost reductions, including CEWS, which offset G&A costs by approximately $3 million.

During the three months ended June 30, 2020, a decision was made to roll back salaries across the Corporation, with an emphasis on Board, executive and senior leader compensation. Effective June 1, 2020, base cash compensation for Board members was reduced by 25%. The President and Chief Executive Officer had his annual base salary reduced by 25%, the Chief Operating Officer and Chief Financial Officer each took a 15% annual base salary reduction, vice presidents received a 12% annual base salary rollback and all other employees received a 7.5% annual base salary rollback.

Stock-based Compensation

	Three months ended June 30		Six months ended June 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Cash-settled expense (recovery)	**$ 9**	$ 5	**$ (9)**	$ (5)
Equity-settled expense	**2**	11	**7**	16
Equity price risk management gain[(1)]	**$ (19)**	$ —	**$ (20)**	$ —
Stock-based compensation	**$ (8)**	$ 16	**$ (22)**	$ 11

(1) Relates to financial derivatives entered into to manage the Corporation's exposure to cash-settled RSUs and PSUs vesting in 2021, 2022 and 2023 granted under the Corporation's stock-based compensation plans. Amounts are unrealized until vesting of the related units occurs. See Risk Management section of this MD&A for further details.

The Corporation's common share price recovered to $3.77 per share as at June 30, 2020, from its value of $1.67 per share as at March 31, 2020, resulting in a $9 million cash-settled stock-based compensation expense during the three months ended June 30, 2020.

During the six months ended June 30, 2020, the Corporation's common share price decreased 49% to $3.77 per share as at June 30, 2020 from its value of $7.39 per share on December 31, 2019 primarily due to the impact of COVID-19 on capital markets which resulted in a $9 million cash-settled stock-based compensation recovery.

Equity-settled stock-based compensation expense decreased for the three and six months ended June 30, 2020, compared to the same periods of 2019, due to a decrease in the fair value of awards granted in the current period and recoveries as a result of reductions in staff. Effective April 1, 2020, a decision was made to reduce the value of target 2020 long- term incentive awards issued to employees and directors by 20%.

Foreign Exchange Gain (Loss), Net

	Three months ended June 30		Six months ended June 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ 116**	$ 74	**$ (162)**	$ 154
US$ denominated cash and cash equivalents	**(2)**	(7)	**9**	(9)
Unrealized net gain (loss) on foreign exchange	**114**	67	**(153)**	145
Realized gain (loss) on foreign exchange	**2**	2	**(1)**	3
Foreign exchange gain (loss), net	**$ 116**	$ 69	**$ (154)**	$ 148

C$ equivalent of 1 US$				
Beginning of period	**1.4120**	1.3360	**1.2965**	1.3646
End of period	**1.3616**	1.3091	**1.3616**	1.3091

During the three months ended June 30, 2020, the Canadian dollar strengthened relative to the U.S. dollar by 4%, resulting in an unrealized foreign exchange gain of $114 million. During the three months ended June 30, 2019, the Canadian dollar strengthened by 2%, resulting in an unrealized foreign exchange gain of $67 million.

During the six months ended June 30, 2020, the Canadian dollar weakened relative to the U.S. dollar by 5%, resulting in an unrealized foreign exchange loss of $153 million. During the six months ended June 30, 2019, the Canadian dollar strengthened by 4%, resulting in an unrealized foreign exchange gain of $145 million.

Net Finance Expense

	Three months ended June 30		Six months ended June 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Interest expense on long-term debt	**$ 60**	$ 69	**$ 124**	$ 141
Interest expense on lease liabilities	**7**	7	**13**	13
Interest income	**—**	(2)	**(2)**	(3)
Net interest expense	**67**	74	**135**	151
Accretion on provisions	**2**	1	**4**	4
Unrealized loss on derivative financial liabilities	**—**	1	**—**	—
Net finance expense	**$ 69**	$ 76	**$ 139**	$ 155

Average effective interest rate	**7.0%**	6.6%	**6.9%**	6.6%

As a result of the senior secured term loan repayment in July 2019 and partial redemptions on the Corporation's senior secured second lien notes and senior unsecured notes during the second half of 2019 and the first quarter of 2020, net finance expense for the three and six months ended June 30, 2020 decreased, compared to the same periods of 2019.

Income Tax

	Three months ended June 30		Six months ended June 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Income tax expense (recovery)	**$ (62)**	$ 12	**$ (64)**	$ (34)
Effective tax rate	**43 %**	(23)%	**15 %**	23 %

As at June 30, 2020, the Corporation had approximately $7.2 billion of available Canadian tax pools and recognized a deferred income tax asset of $325 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

The effective tax rate of 15% for the six months ended June 30, 2020 is lower than the Canadian statutory rate of 25% due to the tax effect of realized and unrealized foreign exchange losses on the Corporation's debt.

During the three months ended June 30, 2019, the Government of Alberta enacted legislation to reduce the corporate tax rate from 12% to 8% by January 1, 2022. As a result, the Corporation recognized a one-time deferred income tax expense of $34 million associated with the rate reduction, as the rate change reduced the value of the Corporation's deferred tax asset as at June 30, 2019. Acceleration of the rate change to 8% by July 1, 2020 was announced during the second quarter of 2020 and had no further impact given the Corporation's tax horizon. The Corporation does not expect to pay Canadian income taxes during the next five years.

7. LIQUIDITY AND CAPITAL RESOURCES

($millions)	**June 30, 2020**	**December 31, 2019**
Second Lien:		
6.5% senior secured second lien notes (June 30, 2020 - US$496 million; December 31, 2019 - US$596 million; due 2025)	**$ 675**	$ 773
Unsecured:		
7.0% senior unsecured notes (June 30, 2020 - US$600 million; December 31, 2019 - US$1 billion; due 2024)	**817**	1,297
7.125% senior unsecured notes (June 30, 2020 - US$1.2 billion; December 31, 2019 - US$nil; due 2027)	**1,634**	—
6.375% senior unsecured notes (June 30, 2020 - US$nil; December 31, 2019 - US$800 million; due 2023)	**—**	1,037
Less:		
Debt redemption premium	**—**	29
Unamortized deferred debt discount and debt issue costs	**(30)**	(13)
Long-term debt	**3,096**	3,123
Cash and cash equivalents	**(120)**	(206)
Net debt(1)	**$ 2,976**	$ 2,917

(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 20 of the interim consolidated financial statements.

During the six months ended June 30, 2020 net debt increased by $59 million due to the decrease in cash and cash equivalents and the weakening of the Canadian dollar relative to the US dollar, partially offset by the partial redemption of its 6.5% senior secured second lien notes.

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

- Fully redeem $1 billion (US$800 million) of the 6.375% senior unsecured notes due January 2023 at a redemption price of 101.063%;
- Partially redeem $530 million (US$400 million) of the US$1.0 billion 7.0% senior unsecured notes due March 2024 at a redemption price of 102.333%; and

- Pay fees and expenses related to the offering.

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

In total, $180 million of cash on hand was used to fund the partial redemption of the second lien notes, to fund the call premiums associated with the redemption of the 2023 and 2024 notes, and to pay debt issue costs associated with the transactions.

The Corporation's cash and cash equivalents balance was $120 million as at June 30, 2020 compared to $206 million as at December 31, 2019. Adjusted funds flow of $166 million during the six months ended June 30, 2020 was more than offset by the repayment of debt and capital expenditures. Refer to the "Cash Flow Summary" section for further details.

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

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

As at June 30, 2020, the Corporation had $785 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $63 million of unutilized capacity under the $500 million EDC facility. A letter of credit of $15 million was issued under the revolving credit facility during the six months ended June 30, 2020. Letters of credit issued under the revolving credit facility are not included in first lien net debt for purposes of calculating the first lien net leverage ratio.

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

Cash Flow Summary

	Three months ended June 30		Six months ended June 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Net cash provided by (used in):				
Operating activities	**$ 117**	$ 302	**$ 216**	$ 233
Investing activities	**(50)**	(41)	**(109)**	(125)
Financing activities	**(7)**	(9)	**(203)**	(17)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(2)**	(7)	**10**	(10)
Change in cash and cash equivalents	**$ 58**	$ 245	**$ (86)**	$ 81

Cash Flow – Operating Activities

The decrease in net cash provided by operating activities for the three and six months ended June 30, 2020 compared to the same periods of 2019 is primarily due to decreased blend sales as a result of lower benchmark crude oil prices and decreased blend sales volumes, partially offset by realized commodity risk management gains.

Cash Flow – Investing Activities

Net cash used in investing activities increased during the three months ended June 30, 2020 compared to the same period of 2019 reflecting timing of working capital changes.

Net cash used in investing activities decreased during the six months ended June 30, 2020 compared to the same period of 2019 which aligns with the Corporation's reduced capital spending.

Cash Flow – Financing Activities

Net cash used in financing activities increased during the six months ended June 30, 2020 compared to the same period of 2019 primarily due to the redemption of a portion of the 6.5% senior secured second lien notes totaling $132 million (US$100 million). Also, debt redemption premiums and other refinancing costs were incurred related to the January 31, 2020 refinancing.

8. RISK MANAGEMENT

Commodity Price Risk Management

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

The Corporation had the following financial commodity risk management contracts relating to crude oil sales and condensate purchases outstanding as at June 30, 2020:

As at June 30, 2020	Volumes (bbls/d)[(1)]	Term	Average Price (US$/bbl)[(1)]
Crude Oil Sales Contracts			
WTI Fixed Price	47,042	Jul 1, 2020 - Dec 31, 2020	$47.70
WTI:WCS Fixed Differential	24,500	Jul 1, 2020 - Dec 31, 2020	$(20.46)
WTI:WCS (USGC) Fixed Differential	1,000	Aug 1, 2020 - Aug 31, 2020	$(3.95)
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	Jul 1, 2020 - Dec 31, 2020	$(7.63)
WTI:Mont Belvieu Fixed Differential	10,950	Jan 1, 2021 - Dec 31, 2021	$(10.37)
WTI:Mont Belvieu Fixed Differential	200	Jan 1, 2022 - Dec 31, 2022	$(11.30)
WTI:Mont Belvieu Fixed % of WTI	7,750	Jul 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 Corporation entered into the following financial commodity risk management contracts relating to crude oil sales between June 30, 2020 and July 27, 2020:

Subsequent to June 30, 2020	Volumes (bbls/d)[(1)]	Term	Average Price (US$/bbl)[(1)]
Crude Oil Sales (Purchase) Contracts			
WTI Fixed Price	25,250	Aug 1, 2020 - Aug 31, 2020	$40.57
WTI Fixed Price	6,370	Oct 1, 2020 - Dec 31, 2020	$41.45

(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.*

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 June 30, 2020:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	**$ (63)**	**$ 60**
Crude oil differential price[(1)]	± US$5.00 per bbl applied to WTI:WCS differential contracts	**$ 31**	**$ (31)**

(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 June 30, 2020:

As at June 30, 2020	Volumes (bbls/d)[1]	Term	Average Price (US$/bbl)[1]
Crude Oil Sales Contracts			
WTI:AWB Fixed Differential	13,150	Jul 1, 2020 - Dec 31, 2020	(20.75)
WTI:AWB Fixed Differential at USGC	11,370	Jul 1, 2020 - Sep 30, 2020	(4.11)
Condensate Purchase Contracts			
WTI:Condensate Fixed Differential	8,200	Jul 1, 2020 - Dec 31, 2020	(5.31)

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

Equity Price Risk Management

The Corporation enters into financial equity price risk management contracts to increase the predictability of the Corporation's cash flow by managing share price volatility. Equity price risk is the risk that changes in the Corporation's own share price impact earnings and cash flows. Earnings and funds flow from operating activities are impacted when outstanding cash-settled RSUs and PSUs, issued under the Corporation's stock-based compensation plans, are revalued each period based on the Corporation's share price. Net cash provided by (used in) operating activities is impacted when these stock-based compensation units are ultimately settled. The Corporation enters into these equity price risk management contracts to manage its exposure on approximately 9 million cash-settled RSUs and PSUs vesting between 2021 and 2023.

9. SHARES OUTSTANDING

As at June 30, 2020, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	Units
Common shares	**302.6**
Convertible securities	
Stock options[1]	**5.3**
Equity-settled RSUs and PSUs	**7.3**

(1) *4.6 million stock options were exercisable as at June 30, 2020.*

As at July 25, 2020, the Corporation had 302.6 million common shares, 5.3 million stock options and 7.0 million equity-settled restricted share units and equity-settled performance share units outstanding, and 4.6 million stock options exercisable.

10. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations as at June 30, 2020. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities, the senior secured second lien notes, and the senior unsecured notes may be retired earlier due to mandatory or discretionary repayments or redemptions.

($millions)	2020	2021	2022	2023	2024	Thereafter	Total
Commitments:							
Transportation and storage[1]	$ 215	$ 436	$ 425	$ 467	$ 452	$ 6,046	$ 8,041
Diluent purchases	70	22	22	18	—	—	132
Other operating commitments	8	15	14	13	11	45	106
Variable office lease costs	2	4	4	4	5	30	49
Capital commitments	1	—	—	—	—	—	1
Total Commitments	296	477	465	502	468	6,121	8,329
Other Obligations:							
Lease obligations	23	47	38	32	32	520	692
Long-term debt[2]	—	—	—	—	817	2,309	3,126
Interest on long-term debt[2]	144	218	218	218	174	250	1,222
Decommissioning obligation[3]	1	5	5	5	5	789	810
Obligations	**$ 464**	**$ 747**	**$ 726**	**$ 757**	**$ 1,496**	**$ 9,989**	**$ 14,179**

(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 June 30, 2020.*

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

Contingencies

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

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

11. NON-GAAP MEASURES

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

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

12. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of coronavirus ("COVID-19"). The outbreak and subsequent measures intended to limit COVID-19 globally have contributed to significant declines and volatility in capital and financial markets, and adversely impacted the global commodity market, most notably the dramatic decline in worldwide demand for crude oil. There are no comparable recent events that provide guidance as to the long term effect that COVID-19 may have, including continuing global efforts to contain the spread and severity of the virus, and as a result, the ultimate impact of the outbreak is highly uncertain and subject to change. The full extent of the impact of COVID-19 on the Corporation’s operations and future financial performance is currently unknown. The continued impact on capital and financial markets on a macro-scale presents uncertainty and risk with respect to the Corporation’s performance, and the estimates and assumptions used by Management in the preparation of its financial results.

Additional estimates, assumptions and judgments in response to COVID-19 have been disclosed in the interim consolidated financial statements as at June 30, 2020 regarding valuation assessments related to the Corporation's inventories, property, plant and equipment, exploration and evaluation assets, long-term pipeline linefill, decommissioning provision and deferred income tax asset.

13. RISK FACTORS

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

Risk related to COVID-19 Global Pandemic

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

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

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

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

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

14. DISCLOSURE CONTROLS AND PROCEDURES

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

15. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

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

16. ABBREVIATIONS

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

Financial and Business Environment

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

Measurement

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

17. ADVISORY

Forward-Looking Information

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

Forward-looking information contained in this document is based on management's expectations and assumptions regarding, among other things: future crude oil, bitumen blend, natural gas, electricity, condensate and other diluent prices, foreign exchange rates and interest rates; the recoverability of MEG's reserves and contingent resources; MEG's ability to produce and market production of bitumen blend successfully to customers; extent and timelines of the Alberta Government's mandatory production curtailment program, future growth, results of operations and production levels; future capital and other expenditures; revenues, expenses and cash flow;

operating costs; reliability; continued liquidity and runway to sustain operations through a prolonged market downturn; ability to reduce oil sands production, including without negative impacts to its assets; anticipated reductions in operating costs as a result of optimization and scalability of certain operations; anticipated sources of funding for operations and capital investments; plans for and results of drilling activity; plans for and results of turnaround activity; the regulatory framework governing royalties, land use, taxes and environmental matters, including the timing and level of government production curtailment and federal and provincial climate change policies, in which MEG conducts and will conduct its business; the impact of MEG's response to the COVID-19 global pandemic; and business prospects and opportunities. By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated.

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

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

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

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

MEG Energy Corp. is an energy company focused on sustainable in situ thermal oil production in the southern Athabasca region of Alberta, Canada. The Corporation is actively developing innovative enhanced oil recovery projects that utilize SAGD extraction methods to improve the responsible economic recovery of oil as well as lower carbon emissions. MEG transports and sells its thermal oil production to refiners throughout North America and internationally. 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 most recently filed 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 of this non-GAAP measure is presented in the "NON-GAAP MEASURES" section of this MD&A.

18. ADDITIONAL INFORMATION

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

19. QUARTERLY SUMMARIES

	2020		2019				2018[1]	
Unaudited	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**(80)**	(284)	26	24	(64)	(48)	(199)	118
Per share, diluted	**(0.26)**	(0.95)	0.09	0.08	(0.21)	(0.16)	(0.67)	0.39
Adjusted funds flow	**89**	78	157	192	227	151	(37)	116
Per share, diluted	**0.29**	0.26	0.51	0.63	0.76	0.50	(0.13)	0.39
Capital expenditures	**20**	54	72	40	33	53	144	139
Cash and cash equivalents	**120**	62	206	154	399	154	318	373
Working capital	**173**	371	123	204	416	175	290	274
Long-term debt	**3,096**	3,212	3,123	3,257	3,582	3,660	3,740	3,544
Shareholders' equity	**3,507**	3,593	3,853	3,828	3,795	3,851	3,886	4,068
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**27.85**	46.17	56.96	56.45	59.82	54.90	58.81	69.50
Differential – WTI:WCS – Edmonton (US$/bbl)	**(11.47)**	(20.53)	(15.83)	(12.24)	(10.67)	(12.29)	(39.43)	(22.25)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(13.44)**	(22.78)	(18.44)	(14.52)	(12.32)	(14.50)	(44.60)	(25.69)
AWB – Edmonton (US$/bbl)	**14.41**	23.39	38.52	41.93	47.50	40.40	14.21	43.81
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(7.29)**	(5.74)	(5.25)	(2.50)	1.64	(0.89)	(6.25)	(5.63)
AWB – U.S. Gulf Coast (US$/bbl)	**20.56**	40.43	51.71	53.95	61.46	54.01	52.56	63.87
C$ equivalent of 1US$ – average	**1.3860**	1.3445	1.3201	1.3207	1.3376	1.3293	1.3215	1.3070
Natural gas – AECO ($/mcf)	**2.21**	2.26	2.70	0.95	1.12	2.86	1.70	1.28
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**100,980**	142,380	134,932	132,455	137,120	132,377	126,750	130,823
Diluent usage – bbls/d	**(30,583)**	(45,166)	(40,585)	(37,463)	(42,000)	(42,555)	(38,467)	(36,967)
Bitumen sales – bbls/d	**70,397**	97,214	94,347	94,992	95,120	89,822	88,283	93,856
Bitumen production – bbls/d	**75,687**	91,557	94,566	93,278	97,288	87,113	87,582	98,751
Steam-oil ratio (SOR)	**2.32**	2.31	2.27	2.26	2.16	2.20	2.22	2.17
Blend sales	**20.96**	36.46	56.55	60.26	69.19	59.02	37.76	63.68
Cost of diluent	**(10.78)**	(17.01)	(9.69)	(6.89)	(6.96)	(8.81)	(22.45)	(14.05)
Bitumen realization	**10.18**	19.45	46.86	53.37	62.23	50.21	15.31	49.63
Transportation and storage – net	**(11.77)**	(8.63)	(10.75)	(10.57)	(10.80)	(11.27)	(10.28)	(9.11)
Third-party curtailment credits	**—**	0.18	(0.21)	(0.37)	(0.89)	—	—	—
Royalties	**(0.05)**	(0.63)	(1.18)	(1.54)	(2.06)	(0.37)	(0.15)	(2.01)
Operating costs – non-energy	**(4.09)**	(4.57)	(4.49)	(4.22)	(4.53)	(5.22)	(4.25)	(4.38)
Operating costs – energy	**(3.00)**	(3.15)	(2.95)	(1.51)	(1.78)	(3.36)	(1.98)	(1.50)
Power revenue	**0.95**	2.21	1.57	1.43	1.65	2.41	1.68	1.54
Realized gain (loss) on commodity risk management	**33.62**	11.97	(0.52)	(4.15)	(5.94)	(2.60)	6.81	(10.16)
Cash operating netback	**25.84**	16.83	28.33	32.44	37.88	29.80	7.14	24.01
Power sales price (C$/MWh)	**28.34**	69.39	49.61	50.30	55.33	70.83	55.38	51.53
Power sales (MW/h)	**98**	129	124	112	118	128	111	117
Average cost of diluent ($/bbl of diluent)	**45.76**	73.09	79.07	77.71	84.95	77.61	89.28	99.37
Average cost of diluent as a % of WTI	**119 %**	118 %	105 %	104 %	106 %	106 %	115 %	109 %
Depletion and depreciation rate per bbl of production	**13.55**	14.83	13.18	13.43	41.22	14.68	13.79	13.85
General and administrative expense per bbl of production	**1.29**	1.96	2.25	1.66	1.81	2.27	2.54	2.35
COMMON SHARES								
Shares outstanding, end of period (000)	**302,645**	299,547	299,508	299,288	299,207	296,857	296,841	296,813
Common share price ($) - close (end of period)	**3.77**	1.67	7.39	5.80	5.02	5.10	7.71	8.03

(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 with periods of significant volatility in 2020, which has ranged from a quarterly average of US$27.85/bbl to US$69.50/bbl, and the differential between WTI and the Corporation's AWB at Edmonton, which has ranged from a quarterly average of US$12.32/bbl to US$44.60/bbl driven by supply/demand fundamentals;
- in early March 2020, and continuing into the second quarter of 2020, global crude oil prices started experiencing multi-decade lows coupled with extreme levels of volatility driven primarily by an unprecedented reduction in global demand due COVID-19;
- the cost of diluent due to changes in Canadian and U.S. benchmark pricing, the timing of diluent inventory purchases and the impact of foreign exchange;
- 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;
- timing of capital projects;
- cost reduction efforts;
- apportionment and the ability to reach USGC markets;
- fluctuations in natural gas and power pricing;
- gains and losses on commodity risk management contracts;
- Alberta Government enacted curtailment rules;
- changes in depletion and depreciation expense as a result of changes in production rates, future development costs and uncertainty of future benefits associated with specific non-core assets;
- exploration expense associated with discontinued exploration and evaluation activities in certain non-core growth properties;
- a decrease in general and administrative expense due to reduction in staffing levels;
- changes in the Corporation's share price and the implementation of financial equity price risk management contracts, and the resulting impact on stock-based compensation;
- planned turnaround and other maintenance activities affecting production; and
- voluntary curtailment efforts associated with uneconomic benchmark pricing environments.

20. ANNUAL SUMMARIES

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

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