MEG ENERGY
Sustainable. Innovative. Responsible.

2020 Report to Shareholders, Management's Discussion and Analysis and Annual Financial Statements

For the year ended December 31, 2020

TSX | MEG

REPORT | 2020

REPORT TO SHAREHOLDERS FOR THE YEAR ENDED DECEMBER 31, 2020

Report to Shareholders for the year ended December 31, 2020

(All financial figures are expressed in Canadian dollars ($ or C$) and all references to barrels are per barrel of bitumen, unless otherwise noted)

MEG Energy Corp. reported full year 2020 operational and financial results on March 3, 2021. Highlights include:

- Free cash flow of $129 million driven by adjusted funds flow of $278 million ($0.91 per share) and disciplined capital spend of $149 million;
- Bitumen production volumes of 82,441 barrels per day (bbls/d) at a steam-oil ratio (SOR) of 2.3;
- Repayment of $132 million of long-term debt concurrent with the refinancing of US$1.2 billion of existing indebtedness;
- General and administrative expense of $49 million which was $19 million, or 28%, lower than 2019;
- Net operating costs of $6.18 per barrel, supported by record low non-energy operating costs of $4.38 per barrel and strong power sales which offset 45% of per barrel energy operating costs resulting in a net energy operating cost of $1.80 per barrel; and
- Exited 2020 with $114 million of cash on hand and MEG's $800 million modified covenant-lite revolver remains undrawn.

“Notwithstanding the incredibly challenging environment our industry faced in 2020, MEG continued to execute on its strategic focus of improving overall cost efficiencies, preserving financial liquidity and enhancing MEG’s competitive position,” says Derek Evans, President and Chief Executive Officer. “In keeping with this strategy, we significantly reduced G&A, repaid indebtedness, extended the maturity runway of outstanding long-term debt and began moving the majority of our barrels to the USGC for the first time. None of this would have been achieved without the commitment, perseverance, and resilience of the MEG team which has my thanks and those of the Board for all their collective and individual efforts during the year.”

Financial Liquidity and Debt Repayment

In the last three years, the Corporation has repaid approximately $2 billion (US$1.5 billion) of long-term debt including $132 million (US$100 million) in 2020.

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

Subsequent to year end, in February 2021, the Corporation successfully closed a private offering of US$600 million in aggregate principal amount of 5.875% senior unsecured notes due February 2029. The net proceeds of the offering plus cash on hand were used to fully redeem the remaining US$600 million of the 7.0% senior unsecured notes due March 2024. Post this refinancing, MEG maintains a 4-year runway until its next debt maturity represented by the remaining US$496 million of 6.50% second lien notes due January 2025.

MEG generated $129 million of free cash flow in 2020 and exited the year with $114 million of cash on hand. The Corporation's $800 million modified covenant-lite revolver, in place until July 2024, remains undrawn.

Blend Sales Pricing and North American Market Access

MEG realized an average AWB blend sales price of US$28.07 per barrel in 2020 compared to US$46.19 per barrel in 2019. The decrease in average AWB blend sales price year over year was primarily a result of the average WTI price decreasing by US$17.63 per barrel. MEG sold 40% of its sales volumes to the US Gulf Coast ("USGC") in 2020 compared to 33% in 2019. The increase in sales to the USGC in 2020 is primarily a result of the Corporation's increased contracted blend transportation capacity on the Flanagan South and Seaway Pipeline systems ("FSP") effective July 1, 2020 from 50,000 bbls/d to 100,000 bbls/d.

Transportation and storage costs averaged US$6.74 per barrel of AWB blend sales in 2020 compared to US$5.70 per barrel of AWB blend sales 2019. The increase in transportation and storage costs is primarily due to the fixed costs associated with increased FSP contracted capacity coupled with lower year over year sales volumes. MEG's AWB blend sales by rail were 16,865 bbls/d in 2020, representing 14% of total blend sales, compared to 19,686 bbls/d, representing 15% of total blend sales in 2019. MEG is not anticipating undertaking any AWB blend sales by rail in 2021.

Operational Performance

Bitumen production averaged 82,441 bbls/d in 2020, compared to 93,082 bbls/d in 2019. Contributing to the decrease was the impact of the Corporation's major planned turnaround at the Phase 1 and 2 facilities which was extended in duration to 75-days and expanded in scope relative to the Corporation's original budget in order to minimize staff levels at site during COVID-19 and maximize utilization of the Corporation's internal resources thereby lowering overall cash costs. MEG also made the decision to advance turnaround activities from 2021 to significantly reduce the 2021 turnaround requirements.

The decrease in 2020 bitumen production was also impacted by the Corporation's decision, in the first half of 2020, to reduce capital investment by $100 million and undertake voluntary price-related production curtailments during the second quarter of 2020 in order to preserve financial liquidity.

Non-energy operating costs were $133 million, or $4.38 per barrel, in 2020 compared to $157 million, or $4.61 per barrel, in 2019. General and administrative expense was $49 million, or $1.62 per barrel, in 2020 compared to $68 million, or $1.99 per barrel, in 2019. Throughout 2020 MEG continued efforts to drive efficiency into its cost structure including reductions in staffing levels as well as temporary salary rollbacks and vendor concessions which contributed to the decrease in expenses year over year. The Corporation also took part in various government led initiatives during 2020, aimed at supporting businesses facing the negative impacts of COVID-19.

Adjusted Funds Flow and Net Loss

The Corporation's adjusted funds flow was $278 million in 2020 compared to $726 million in 2019. The decrease in adjusted funds flow was driven primarily by the 31% decrease in the WTI price year over year partially offset by a realized commodity risk management gain of $343 million.

The Corporation recognized a net loss of $357 million in 2020 compared to a net loss of $62 million in 2019. The increase in the net loss year over year was largely driven by significant non-cash items including a $366 million exploration expense associated with certain non-core assets and a decrease in the unrealized foreign exchange gain driven by the strengthening of the Canadian dollar. These were partially offset by an unrealized commodity risk management gain as a result of weaker forward commodity prices compared to an unrealized commodity risk management loss in the same period of 2019.

Capital Expenditures

Capital expenditures in 2020 totaled $149 million compared to $198 million in 2019. The decrease in capital spending in 2020, compared to 2019, reflects the Corporation's decision to reduce its original 2020 capital budget of $250 million by approximately $100 million due to the unprecedented negative macro oil price environment experienced in 2020. Capital expenditures during 2020 primarily consisted of sustaining and maintenance and turnaround activities.

Sustainability

In 2020 we continued to advance our Environmental, Social and Governance ("ESG") activities and strategy with corporate commitments to supporting the Paris Agreement, the approval of our long-term ambition of reaching net-zero GHG emissions (scope 1 and scope 2) by 2050, and our commitment to human rights as reflected in the UN Universal Declaration of Human Rights.

We remain committed to ESG leadership and look forward to updating our performance in that regard with the release of our 2020 Sustainability Report mid-2021

COVID-19 Global Pandemic

The health and safety of its people is the Corporation's first priority. The Corporation's business activities have been declared an essential service by the Alberta Government and the Corporation remains committed to ensuring the health and safety of all its personnel and business partners, and the safe and reliable operation of the Christina Lake facility. At the onset of the global pandemic, a COVID-19 task force was established by the Corporation comprised of members of senior management and employees as well as third party expert consultants to promptly implement measures to protect the health and safety of the Corporation's work force and the public, as well as to ensure continuity of operations. The implementation of mandatory self-quarantine policies, travel restrictions, screening protocols, 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 at the onset of the pandemic in March 2020, revising shift schedules and increasing appropriate protective equipment, were proactively established. To date, the Corporation has not experienced any COVID-19 outbreaks at any of its locations.

The Corporation continues to monitor the developing COVID-19 situation to determine what, if any, additional measures might need to be taken to ensure that the health and safety of its people remain a top priority. In September, MEG safely returned to near-normal operations, with new safety measures in place, including the majority of staff returning to regular work locations. In December 2020, the Corporation reverted to having staff who are able to work remotely to do so, to reduce risk of exposure. Flexibility and adaptability continue to be integral to the risk management strategy.

Outlook

Announced December 7, 2020, MEG's capital investment plan for 2021 of $260 million includes $245 million to be directed towards sustaining and maintenance capital and the remaining $15 million directed towards non-discretionary field infrastructure, regulatory and corporate capital costs.

MEG's 2021 annual average bitumen production volumes are targeted to be in the range of 86,000 - 90,000 bbls/d and the Corporation's 2021 non-energy operating costs and general and administrative expense are targeted to be in the range of $4.60 - $5.00 per barrel and $1.70 - $1.80 per barrel, respectively.

2021 Commodity Price Risk Management

To support MEG's 2021 capital budget announced December 7, 2020, MEG entered into benchmark WTI fixed price hedges and enhanced WTI fixed price hedges with sold put options for approximately 47% (60% 1H, 33% 2H) of forecast bitumen production at an average price of US$46.66 per barrel. These hedges were put in place to protect funding of the Corporation's 2021 capital program with internally generated cash flow down to a US$30 per barrel WCS price and to protect MEG's balance sheet. The first half weighting of these hedges reflect the first half weighting of MEG's capital investment profile as well as the uncertainty regarding pace of 2021 economic recovery at time of execution.

MEG has hedged approximately 23% of its forecast Edmonton WTI:WCS differential exposure (41% 1H, 5% 2H) at an average differential of US$13.42 per barrel. MEG has also hedged approximately 40% of its expected 2021 condensate requirements at a landed-at-Edmonton price of 96% of WTI, approximately 35% of expected 2021 natural gas requirements at an average price of C$2.62 per GJ and fixed the sales price on approximately 25% of expected 2021 power available for sale at an average price of C$62.80 per MW. The table below reflects MEG's 2021 hedge positions.

	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2021
	Forecast Period				
WTI Hedges					
WTI Fixed Price Hedges					
Volume (bbls/d)	37,361	13,000	—	—	**12,453**
Weighted average fixed WTI price (US$/bbl)	$ 48.28	$ 46.31	$ —	$ —	**$ 47.77**
Enhanced WTI Fixed Price Hedges with Sold Put Options(1)					
Volume (bbls/d)	29,000	29,000	29,000	29,000	**29,000**
Weighted average fixed WTI price (US$/bbl) / Put option strike price (US$/bbl)	$ 46.18 / $ 38.79	$ 46.18 / $ 38.79	$ 46.18 / $ 38.79	$ 46.18 / $ 38.79	**$ 46.18 / $ 38.79**
WTI:WCS Differential Hedges					
Volume(2) (bbls/d)	15,000	43,000	4,000	—	**15,468**
Weighted average fixed WTI:WCS differential (US$/bbl)	$(14.44)	$(13.27)	$(11.18)	$ —	**$(13.42)**
Condensate Hedges					
Volume(3) (bbls/d)	15,495	18,211	14,028	14,028	**15,433**
Weighted average % of WTI landed in Edmonton (%)(4)	96 %	97 %	96 %	96 %	**96 %**
Natural Gas Hedges					
Volume(5) (GJ/d)	57,500	42,500	42,500	42,500	**46,199**
Weighted average fixed AECO price (C$/GJ)	$ 2.64	$ 2.61	$ 2.61	$ 2.61	**$ 2.62**
Power Hedges					
Quantity(6) (MWh)	20	35	35	35	**31**
Weighted average fixed price (C$/MW)	$ 63.06	$ 62.75	$ 62.75	$ 62.75	**$ 62.80**

(1) *If in any month of 2021 the month average WTI settlement price is US$38.79 per barrel (the sold put option) or better, MEG will receive US$46.18 per barrel (the fixed price swap) on each barrel hedged in that month. If in any month of 2021 the month average WTI settlement price is less than US$38.79 per barrel, MEG will receive the month average WTI settlement price in that month plus US$7.39 per barrel (the swap spread) on each barrel hedged in that month.*

(2) *Includes 9,833 bbls/d (Q1) and 15,000 bbls/d (Q2) of physical forward blend sales at fixed WTI:AWB differentials.*

(3) *Includes approximately 4,500 bbls/d of physical forward condensate purchases for the full year 2021 (annual average).*

(4) *The average % of WTI landed in Edmonton includes estimated net transportation costs to Edmonton.*

(5) *Includes 7,466 GJ/d of physical forward natural gas purchases for the full year 2021 (annual average) at a fixed AECO price.*

(6) *Represents physical forward power sales at a fixed power price.*

ADVISORY

Forward-Looking Information

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

Non-GAAP Measures

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

Free Cash Flow

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

	Three months ended December 31		Year ended December 31	
($millions)	**2020**	**2019**	**2020**	**2019**
Net cash provided by (used in) operating activities	**$ 115**	$ 225	**$ 302**	$ 631
Net change in non-cash operating working capital items	**(34)**	(52)	**(63)**	110
Funds flow from operations	**81**	173	**239**	741
Adjustments:				
Contract cancellation[(1)]	**—**	(20)	**33**	(20)
Net change in other liabilities[(2)]	**3**	3	**3**	3
Decommissioning expenditures	**—**	1	**3**	2
Adjusted funds flow	**$ 84**	$ 157	**$ 278**	$ 726
Capital expenditures	**(40)**	(72)	**(149)**	(198)
Free cash flow	**$ 44**	$ 85	**$ 129**	$ 528

(1) During 2020 these costs were incurred to mitigate rail sales contract exposure. The economic decision to divert sales volumes from rail contracts at Edmonton to the USGC more than recovered the cost of contract cancellations. During the fourth quarter of 2019, the Corporation agreed to relieve the Alberta Petroleum Marketing Commission of all obligations pursuant to a crude oil purchase and sale agreement in exchange for a payment of $20 million. Contract cancellation costs or recoveries are excluded from adjusted funds flow as they are not considered part of ordinary continuing operating results.

(2) Includes the change in liability associated with the termination of a long-term transportation contract that was previously expensed.

Cash Operating Netback

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the year ended December 31, 2020 was approved by the Corporation's Board of Directors on March 3, 2021. This MD&A should be read in conjunction with the Corporation's audited annual consolidated financial statements and notes thereto for the year ended December 31, 2020 and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the audited annual consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in millions of Canadian dollars, except where otherwise indicated.

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

MD&A - Table of Contents

1. BUSINESS DESCRIPTION 7
2. OPERATIONAL AND FINANCIAL HIGHLIGHTS 8
3. FOURTH QUARTER OF 2020 11
4. SUSTAINABILITY 12
5. RESULTS OF OPERATIONS 13
6. OUTLOOK 21
7. BUSINESS ENVIRONMENT 22
8. OTHER OPERATING RESULTS 24
9. SUMMARY OF ANNUAL INFORMATION 28
10. LIQUIDITY AND CAPITAL RESOURCES 29
11. RISK MANAGEMENT 31
12. SHARES OUTSTANDING 33
13. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES 33
14. NON-GAAP MEASURES 34
15. CRITICAL ACCOUNTING POLICIES AND ESTIMATES 34
16. TRANSACTIONS WITH RELATED PARTIES 35
17. RISK FACTORS 35
18. DISCLOSURE CONTROLS AND PROCEDURES 44
19. INTERNAL CONTROLS OVER FINANCIAL REPORTING 45
20. ABBREVIATIONS 46
21. ADVISORY 46
22. ADDITIONAL INFORMATION 48
23. QUARTERLY SUMMARIES 49
24. ANNUAL SUMMARIES 51

1. BUSINESS DESCRIPTION

MEG is an energy company focused on sustainable in situ thermal oil production in the southern Athabasca oil 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 thermal oil (known as Access Western Blend or "AWB") to customers throughout North America and internationally.

MEG owns a 100% working interest in over 450 square miles of mineral leases. In the GLJ Petroleum Consultants Ltd. ("GLJ") report, which is dated effective December 31, 2020, GLJ estimated that the leases it had evaluated contained approximately 2.0 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.

The Christina Lake Project, which contains all of the Corporation's 2P reserves has regulatory approval in place for 210,000 bbls/d of production. At a design steam oil ratio of 2.4, MEG has developed oil processing capacity of approximately 100,000 bbls/d at its Christina Lake central plant facility, prior to any impact from scheduled maintenance activity or outages, through the phased construction of the Christina Lake Project as well as several low-cost debottlenecking and expansion projects and the application of its proprietary reservoir technologies. The typical average annual production decline rate at the Christina Lake Project is approximately 10% to 15% and at the current production of approximately 90,000 bbls/d, MEG has a proved plus probable (2P) reserve life index of approximately 60 years.

The Corporation has been able to realize production growth at the Christina Lake Project while minimizing GHG emissions intensity through the application of its proprietary technologies. Specifically, the Corporation's enhanced Modified Steam and Gas Push ("eMSAGP") technology reduces the amount of steam required to produce a barrel of bitumen. Furthermore, the Corporation continues testing of its proprietary enhanced Modified VAPour EXtraction ("eMVAPEX") technology at the Christina Lake Project, which involves the targeted injection of light hydrocarbons in replacement of steam. The Corporation also uses cogeneration, also known as combined heat and power generation, to create steam and power from a single heat source. The application of eMSAGP and cogeneration have enabled MEG to lower its GHG emission intensity more than 20% below the *in situ* industry volume weighted average calculated based on data reported to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. By applying the eMSAGP process to significant portions of the Christina Lake Project, MEG achieved an average steam oil ratio of 2.3 in 2020 compared to the *in situ* industry volume weighted average of 3.1[(1)].

Marketing Strategy

The Corporation employs a marketing strategy that delivers and sells its production to oil markets throughout North America and internationally. The Corporation owns, leases and contracts for services on multiple facilities to transport, store and deliver AWB to customers. Prior to July 1, 2020, MEG had 50,000 bbls/d of contracted AWB transportation capacity on the Flanagan South and Seaway pipeline ("FSP") systems providing pipeline transportation directly to U.S. Gulf Coast ("USGC") refineries and export terminals. On July 1, 2020, the Corporation's contracted AWB transportation capacity increased to 100,000 bbls/d on FSP. The Corporation is also a shipper on the Trans Mountain Expansion Project which, when in service, will provide the Corporation with 20,000 bbls/d of contracted AWB transportation capacity to Canada's west coast. The Corporation has also contracted oil storage capacity of 2.8 million barrels in Alberta and strategic locations in the U.S., with marine export capacity at select USGC terminals. This combination of pipeline access, storage capacity and marine export capacity, along with rail loading capacity at the Bruderheim Terminal, comprises the Corporation's strategy of having long-term and reliable market access to world oil prices for its production.

The Corporation has a long-term commitment to deliver AWB on the Access Pipeline from its Christina Lake Project to the Edmonton market connecting to local refineries and export pipelines. The Access Pipeline is comprised of an AWB blend pipeline system and diluent pipeline system. The AWB blend pipeline system runs from the Christina Lake Project to Edmonton. The diluent pipeline system runs from the Edmonton area to the Corporation's Christina Lake Project and allows the Corporation to effectively manage its local and import sourced diluent supply for

[(1)] *Annual 2020 data as per the Alberta Energy Regulator ST53.*

purposes of blending with its Christina Lake production. The diluent system receives volumes from numerous local diluent production streams and fractionation facilities as well as imported diluent volumes from inbound pipelines and rail terminals. The diluent system is well connected to key pipeline and storage systems in the Edmonton/Fort Saskatchewan corridor, including the Enbridge TEPPCO and Southern Lights import pipelines for access to Mont Belvieu supply. This system provides a range of diluent supply alternatives and helps to mitigate diluent supply and price risk.

In the Edmonton area, MEG has contracted approximately 1.4 million barrels of storage and terminalling capacity, including approximately 900,000 barrels of capacity at the Stonefell Terminal. The Stonefell Terminal is connected to the Access Pipeline System and provides the Corporation with the ability to: (i) sell and deliver AWB to a variety of markets; (ii) access multiple sources of diluent; and (iii) store both bitumen blend and diluent in periods of market and transportation disruptions or constraints. Stonefell Terminal is directly connected by pipeline to the Bruderheim Terminal, where MEG has loading capacity for AWB transport by rail. The Corporation does not anticipate undertaking any AWB blend sales by rail in 2021.

The Corporation has contracted for pipeline capacity, storage capacity and marine export capacity in the USGC area. Specifically, MEG has contracted for approximately 1 million barrels of storage capacity, along with marine export capacity, at Beaumont, Texas. MEG has also contracted for capacity on the Bayou Bridge pipeline and 350,000 barrels of storage capacity at St. James, Louisiana.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The Corporation demonstrated resilience throughout 2020 as it took definitive action to enhance its strong liquidity and protect its asset base in the face of the market conditions induced by the COVID-19 global pandemic ("COVID-19").

COVID-19 Response

On March 17, 2020, Alberta's Chief Medical Officer of Health declared a public health emergency in an effort to combat the spread of COVID-19 and on March 27, 2020 the Corporation's business activities were declared an essential service by the Alberta Government. At the onset of the global pandemic, the Corporation established a COVID-19 task force comprised of members of senior management and employees as well as third party expert consultants to promptly implement measures to protect the health and safety of the Corporation's work force and the public, as well as to ensure continuity of operations. The Corporation directed the vast majority of its office staff and certain non-essential field staff to work from home, and implemented mandatory self-quarantine policies, travel restrictions, screening protocols, enhanced cleaning and sanitation measures, social distancing measures, revised shift schedules and increased appropriate protective equipment. To date, the Corporation has not experienced any COVID-19 outbreaks at any of its locations.

In September 2020, the Corporation safely returned to near-normal operations, with new safety measures in place, including the majority of staff returning to regular work locations. After COVID-19 infection rates began to rise significantly in early December 2020, in accordance with public health directives, the Corporation directed staff who are able to work from home to do so in order to reduce risks of exposure. Flexibility and adaptability continue to be integral to the Corporation's response to the pandemic. The Corporation continues to monitor the developing COVID-19 situation to determine what, if any, additional measures might need to be taken to ensure that the health and safety of its people remain a top priority.

Financial Liquidity and Capital Resources

Considerable market volatility dominated 2020 driven by the spread of COVID-19 and subsequent measures intended to limit the outbreak globally which had an unprecedented impact on global commodity prices. The first half of 2020 was characterized by extremely negative movements in commodity prices coupled with unprecedented uncertainty regarding near-term crude oil supply and demand, while the second half of 2020 saw an improvement in the stability of the global oil market. During 2020, the Corporation was able to enhance its financial position, including protecting liquidity, with a robust commodity price risk management program which resulted in a $343 million realized commodity risk management gain and partially insulated the Corporation's adjusted funds flow from the impact of the extremely negative volatility in the oil price environment. In comparison, a realized commodity risk management loss of $113 million was realized in 2019.

The Corporation generated adjusted funds flow of $278 million in 2020 compared to $726 million in 2019, a 62% decrease, reflecting a lower cash operating netback of $19.22 per barrel in 2020 compared to $32.15 per barrel in 2019. The decrease in cash operating netback was attributable to a lower blend sales price driven by the decline in global crude oil prices and reduced blend sales volumes, partially offset by realized gains on commodity price risk management contracts. Cash operating netback during 2020 was also impacted by higher per barrel transportation and storage costs associated with incremental capacity on FSP coupled with lower year over year sales volumes. The Corporation continues to execute on its long-term strategy of market diversification to improve its netback. To the extent that marketing asset capacity is underutilized, the Corporation has and will continue to look to mitigate these associated costs through short and medium-term third-party contracts.

On January 31, 2020, the Corporation reduced total debt outstanding by $132 million, refinanced US$1.2 billion of its indebtedness to extend the Corporation's nearest long-term maturity to 2024 (from 2023). The Corporation's modified covenant-lite $800 million revolving credit facility is in place until July 2024 and remains undrawn.

Subsequent to December 31, 2020, on February 2, 2021 the Corporation refinanced US$600 million of its indebtedness to extend the Corporation's nearest long-term maturity to 2025 (from 2024).

As at December 31, 2020 cash-on-hand was $114 million.

Other Highlights

The Corporation recognized a net loss of $357 million in 2020 compared to $62 million during 2019 largely driven by the impact of lower commodity prices on the Corporation's cash operating netback. Significant non-cash items also impacted the increase in the net loss which included a $366 million exploration expense associated with certain non-core assets and a decrease in the unrealized foreign exchange gain driven by the Canadian dollar strengthening less in 2020. These were partially offset by an unrealized commodity risk management gain as a result of weaker forward commodity prices compared to an unrealized commodity risk management loss in the same period of 2019.

Total capital spending of $149 million during 2020 was primarily focused on sustaining and maintenance capital and turnaround activities compared to $198 million during 2019. In March and May of 2020, the Corporation announced a cumulative reduction in its 2020 capital investment program of $100 million to preserve financial liquidity. Approximately 80% of the decreased planned capital expenditures were related to well capital.

Annual bitumen production averaged 82,441 bbls/d in 2020 compared to 93,082 bbls/d in 2019. The decrease in average annual bitumen production was predominantly driven by an extended major planned turnaround, reduced capital investment and voluntary price-related production curtailments in April and May 2020 as the Corporation responded to market volatility. The Corporation successfully completed a 75-day major planned turnaround at the Phase 1 and 2 facilities, which began in early June 2020 and was completed mid-August 2020, at a total cost of $25 million. Proving its operational flexibility, the Corporation strategically advanced key turnaround activities from 2021 and extended the duration of turnaround activities to contain labour costs.

Throughout 2020 the Corporation focused on rationalizing ongoing general and administrative ("G&A") expense and non-energy operating costs through reductions in staffing levels and ongoing administrative costs, combined with non-recurring activities including salary rollbacks, vendor concessions and the application for various government support initiatives aimed at supporting businesses facing the negative impacts of COVID-19. The Corporation’s G&A and non-energy operating costs decreased by a combined $43 million during 2020, including the impact of non-recurring efforts.

2021 Outlook

On December 7, 2020, the Corporation announced its 2021 capital investment plan, including a capital budget of $260 million, which is expected to be fully funded within internally generated 2021 cash flow.

The Corporation is estimating 2021 non-energy operating costs and G&A expense to be in the range of $4.60 - $5.00 per barrel and $1.70 - $1.80 per barrel, respectively.

Average annual bitumen production for 2021 is expected to be 86,000 to 90,000 barrels per day.

Selected Operational and Financial Information

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

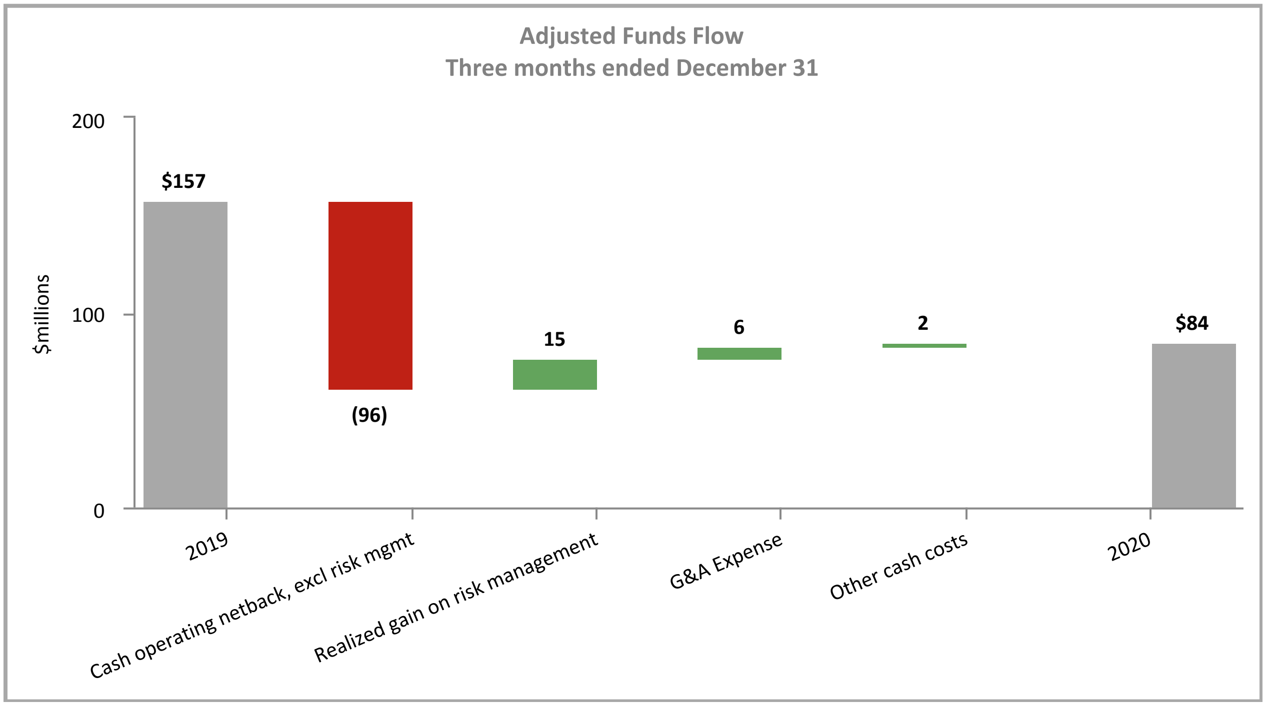
	Three months ended December 31		Year ended December 31	
($millions, except as indicated)	**2020**	**2019**	**2020**	**2019**
Bitumen production - bbls/d	91,030	94,566	82,441	93,082
Steam-oil ratio	2.31	2.27	2.32	2.22
Bitumen sales - bbls/d	95,731	94,347	82,722	93,587
Bitumen realization - $/bbl	38.64	46.86	27.23	53.21
Net operating costs - $/bbl(1)	6.98	5.87	6.18	5.24
Non-energy operating costs - $/bbl	4.70	4.49	4.38	4.61
Cash operating netback - $/bbl(2)	18.66	28.33	19.22	32.15
Adjusted funds flow(3)	84	157	278	726
Per share, diluted	0.27	0.51	0.91	2.41
Revenue	786	992	2,292	3,931
Net earnings (loss)	16	26	(357)	(62)
Per share, diluted	0.05	0.09	(1.18)	(0.21)
Capital expenditures	40	72	149	198
Cash and cash equivalents	114	206	114	206
Long-term debt - C$	2,912	3,123	2,912	3,123
Long-term debt - US$	2,283	2,409	2,283	2,409

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

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

(3) Refer to Note 26 of the 2020 audited annual consolidated financial statements for further details.

3. FOURTH QUARTER OF 2020



The following table is provided to reconcile the Corporation's net cash provided by operating activities to adjusted funds flow for the fourth quarters of 2020 and 2019:

	Three months ended December 31	
(millions)	**2020**	**2019**
Net cash provided by (used in) operating activities	**$ 115**	$ 225
Net change in non-cash operating working capital items	**(34)**	(52)
Funds flow from (used in) operations	**81**	173
Adjustments:		
Contract cancellation[(1)]	**—**	(20)
Decommissioning expenditures	**—**	1
Net change in other liabilities[(2)]	**3**	3
Adjusted funds flow	**$ 84**	$ 157

(1) *During the fourth quarter of 2019, the Corporation agreed to relieve the Alberta Petroleum Marketing Commission of all obligations pursuant to a crude oil purchase and sale agreement in exchange for a payment of $20 million. Contract cancellation costs or recoveries are excluded from adjusted funds flow as they are not considered part of ordinary continuing operating results.*

(2) *Includes the change in liability associated with the termination of a long-term transportation contract that was previously expensed.*

The Corporation generated adjusted funds flow of $84 million in the fourth quarter of 2020 compared to $157 million in the fourth quarter of 2019, a 46% decrease, reflecting a lower cash operating netback of $18.66 per barrel in the fourth quarter of 2020 compared to $28.33 per barrel in the fourth quarter of 2019. Contributing to the decreased cash operating netback was a lower blend sales price due to a lower WTI price partially offset by a narrower WTI:AWB differential and a lower cost of diluent during the fourth quarter of 2020. The decrease in cash operating netback was also impacted by an increase in transportation expense as a result of increased fixed costs on FSP due to the Corporation's increased capacity commitment which began in July 2020.

	Three months ended December 31			
	2020		2019	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	**$ 559**		$ 706	
Sales from purchased product[1]	**213**		281	
Petroleum revenue	**772**		987	
Purchased product[1]	**(197)**		(284)	
Blend sales[2]	**$ 575**	**$ 45.75**	$ 703	$ 56.55
Cost of diluent	**(235)**	**(7.11)**	(295)	(9.69)
Bitumen realization	**340**	**38.64**	408	46.86
Transportation and storage[3]	**(124)**	**(14.11)**	(93)	(10.75)
Third-party curtailment credits[4]	**—**	**0.03**	(2)	(0.21)
Royalties	**(1)**	**(0.23)**	(11)	(1.18)
Net operating costs	**(61)**	**(6.98)**	(52)	(5.87)
Cash operating netback - excludes realized commodity risk management	**154**	**17.35**	250	28.85
Realized gain (loss) on commodity risk management	**11**	**1.31**	(4)	(0.52)
Cash operating netback[5]	**$ 165**	**$ 18.66**	$ 246	$ 28.33
Bitumen sales volumes - bbls/d		**95,731**		94,347

(1) Sales and purchases of oil products related to marketing asset optimization activities.
(2) Blend sales per barrel are based on blend sales volumes.
(3) Transportation and storage includes costs associated with moving and storing blended barrels to optimize 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.

The Corporation recognized net earnings of $16 million for the three months ended December 31, 2020 compared to net earnings of $26 million for the three months ended December 31, 2019 as a result of an increase in the unrealized foreign exchange gain offset by a decrease in cash operating netback and an increase in the unrealized commodity risk management loss.

4. SUSTAINABILITY

MEG's approach to sustainability reflects its understanding of the challenges presented by climate change and the energy transition and its commitment to taking appropriate actions. As the world moves towards a low-carbon future, MEG's business strategy recognizes the impact of reduced use of fossil fuels and addresses the risks arising out of climate change concerns. Although the timing and impact of the energy transition could be highly indeterminate, MEG is focused on enhancing its position as a sustainable low-cost producer and achieving net zero emissions.

In 2020, MEG's Board of Directors committed to supporting the Paris Agreement and approved the Corporation's long-term goal of reaching net zero GHG emissions (Scope 1 and Scope 2) by 2050.

In addition, progress on ESG in 2020 included (a) the completion of an ESG materiality assessment in accordance with the Sustainability Accounting Standards Board ("SASB") standards to identify MEG's ESG priorities and initiatives, (b) the development of a Human Rights Policy Statement reflecting the Corporation's commitment to human rights as set out in the UN Universal Declaration of Human Rights and (c) the enhancement of ESG metrics including increased alignment with SASB recommendations.

MEG is also a supporter of the Task Force on Climate-related Financial Disclosures ("TCFD") recommendations and in 2020 MEG advanced its CDP Climate Disclosure and released a TCFD Index linking MEG's current disclosures to

TCFD recommendations. This TCFD Index is available in the "Sustainability" section of the Corporation's website at www.megenergy.com.

MEG's Corporate Performance Scorecard continues to reflect the integration of ESG into MEG's business. In particular, ESG-related performance indicators make up a significant portion (approximately 40% in 2020 and 37% in 2021) of MEG's Corporate Performance Scorecard which impacts both executive and employee compensation.

In 2021 MEG's strategic ESG initiatives include:

- Advancing technologies to reduce GHG emissions;
- Developing short and medium term targets to progress MEG's commitment to achieve net zero GHG emissions (Scope 1 and Scope 2) by 2050;
- Progressing MEG's alignment with TCFD recommendations on climate scenario analysis;
- Advancement of MEG's Inclusion and Diversity and Indigenous awareness initiatives; and
- Publication of an updated ESG report and continued enhancement of all other ESG disclosure.

Additional information regarding the Corporation's ESG actions, including the ESG Report, CDP Climate Response and CDP Water Response, is available in the "Sustainability" section of the Corporation's website at www.megenergy.com.

5. RESULTS OF ANNUAL OPERATIONS

Bitumen Production and Steam-Oil Ratio

	2020	2019
Bitumen production – bbls/d	**82,441**	93,082
Steam-oil ratio (SOR)	**2.32**	2.22

Bitumen Production

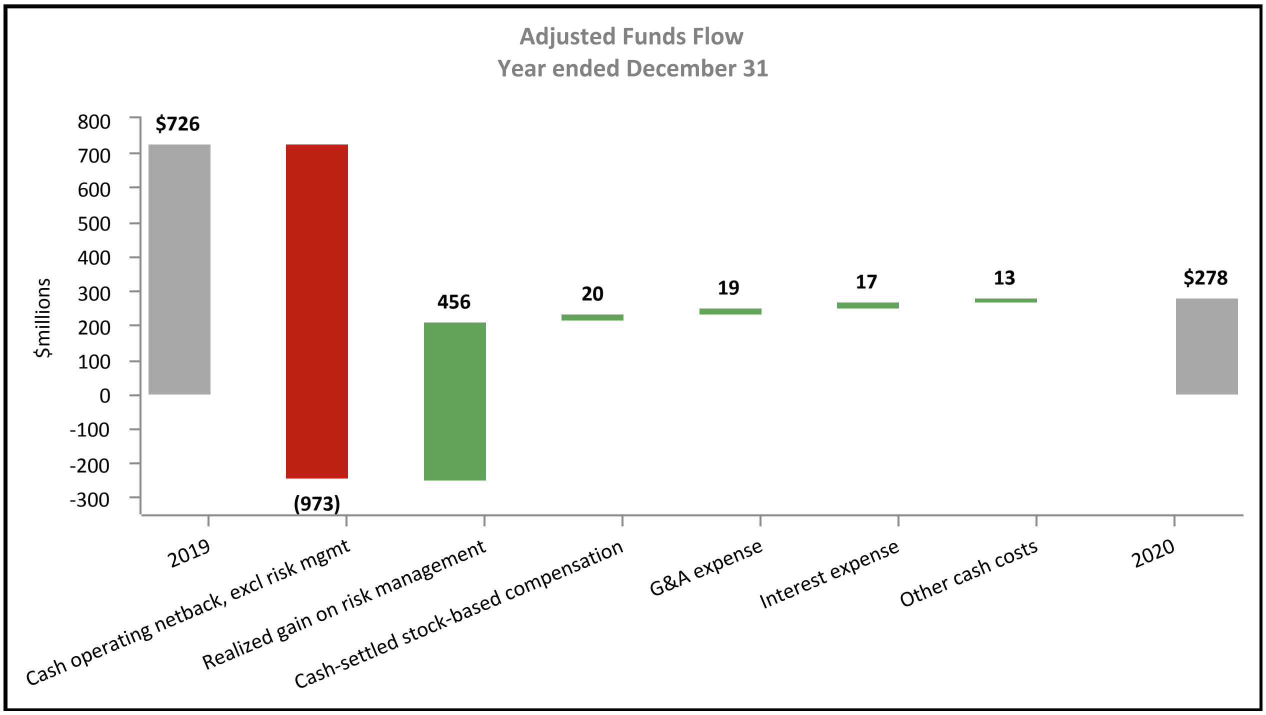
Average annual bitumen production decreased 11% during the year ended December 31, 2020 compared to the same period of 2019. The largest contributing factor was the major planned turnaround at the Phase 1 and 2 facilities, which began in early June 2020 and was completed mid-August 2020. The 2020 turnaround was extended in duration to 75-days and expanded in scope, relative to base budget, in order to minimize staff levels at site during COVID-19 and maximize utilization of the Corporation's internal resources thereby lowering overall cash costs. The Corporation also made the decision to advance turnaround activities from 2021 to reduce the 2021 turnaround requirements.

The decrease in 2020 bitumen production was also impacted by the Corporation's decision, in the first half of 2020, to reduce capital investment by $100 million in order to preserve financial liquidity due to the negative economic impact of COVID-19 and voluntary price-related production curtailments during the second quarter of 2020 as the Corporation responded to market volatility. Annual bitumen production in 2019 was limited by the Alberta Government mandated production curtailment rules which did not impact production in 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 SOR increased for the year ended December 31, 2020, compared to the same period of 2019, due to the timing of new well pairs and wells being brought into steam circulation and production, as well as actively managing production levels in response to extreme price volatility associated with COVID-19 influenced demand destruction and turnaround activities.

Adjusted Funds Flow



During the year ended December 31, 2020, adjusted funds flow decreased compared to the same period of 2019, driven by the Corporation's reduced cash operating netback which was impacted by a decrease in global crude oil prices, punctuated by a period of significant decline during the second quarter of 2020, and reduced sales volumes, partially offset by realized gains on commodity price risk management contracts. The continuing priority to drive cost efficiencies into the business as the Corporation maneuvers a volatile market has resulted in reduced G&A expense and non-energy operating costs, and lower cash interest costs as a result of overall debt reduction. These cost reductions partially mitigated the decrease in adjusted funds flow during the year ended December 31, 2020.

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

($millions)	**2020**	2019
Net cash provided by (used in) operating activities	**$ 302**	$ 631
Net change in non-cash operating working capital items	**(63)**	110
Funds flow from operations	**239**	741
Adjustments:		
Contract cancellation[1]	**33**	(20)
Decommissioning expenditures	**3**	2
Net change in other liabilities[2]	**3**	3
Adjusted funds flow	**$ 278**	$ 726

(1) During 2020 these costs were incurred to mitigate rail sales contract exposure. The economic decision to divert sales volumes from rail contracts at Edmonton to the USGC more than recovered the cost of contract cancellations. During the fourth quarter of 2019, the Corporation agreed to relieve the Alberta Petroleum Marketing Commission of all obligations pursuant to a crude oil purchase and sale agreement in exchange for a payment of $20 million. Contract cancellation costs or recoveries are excluded from adjusted funds flow as they are not considered part of ordinary continuing operating results.

(2) Includes the change in liability associated with the termination of a long-term transportation contract that was previously expensed.

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.

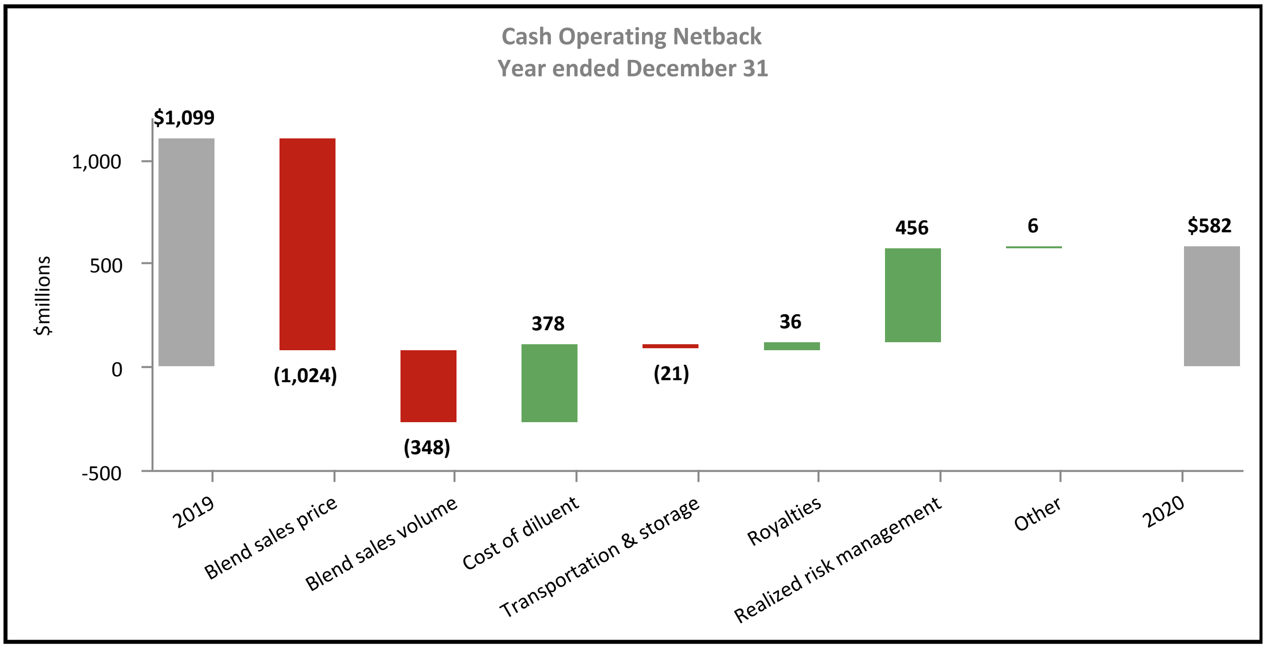
Cash Operating Netback

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

	2020		2019	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	**$ 1,594**		$ 2,996	
Sales from purchased product[1]	**650**		907	
Petroleum revenue	**2,244**		3,903	
Purchased product[1]	**(613)**		(900)	
Blend sales[2]	**$ 1,631**	**$ 37.65**	$ 3,003	$ 61.29
Cost of diluent	**(807)**	**(10.42)**	(1,185)	(8.08)
Bitumen realization	**824**	**27.23**	1,818	53.21
Transportation and storage[3]	**(391)**	**(12.92)**	(370)	(10.84)
Third-party curtailment credits[4]	**2**	**0.06**	(13)	(0.37)
Royalties	**(9)**	**(0.31)**	(45)	(1.30)
Net operating costs	**(187)**	**(6.18)**	(178)	(5.24)
Cash operating netback - excludes realized commodity risk management	**239**	**7.88**	1,212	35.46
Realized gain (loss) on commodity risk management	**343**	**11.34**	(113)	(3.31)
Cash operating netback[5]	**$ 582**	**$ 19.22**	$ 1,099	$ 32.15
Bitumen sales volumes - bbls/d		**82,722**		93,587

(1) *Sales and purchases of oil products related to marketing asset optimization activities.*
(2) *Blend sales per barrel are based on blend sales volumes.*
(3) *Transportation and storage includes costs associated with moving and storing blended barrels to optimize 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 transportation and storage contracts 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 elimination 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 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.

	2020		2019	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	**$ 1,594**		$ 2,996	
Sales from purchased product[1]	**650**		907	
Petroleum revenue	**$ 2,244**		$ 3,903	
Purchased product[1]	**(613)**		(900)	
Blend sales[2]	**$ 1,631**	**$ 37.65**	$ 3,003	$ 61.29
Cost of diluent	**(807)**	**(10.42)**	(1,185)	(8.08)
Bitumen realization	**$ 824**	**$ 27.23**	$ 1,818	$ 53.21

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

During the year ended December 31, 2020, the blend sales price decreased by $23.64 per barrel, or 39%, compared to the same period of 2019. The decrease in blend sales price during the year ended December 31, 2020 is due to a lower WTI price and a wider WTI:AWB differential at the USGC as the Corporation sold more barrels into the USGC during the second half of 2020.

The WTI price experienced a significant decline in March, April and May of 2020, largely driven by unprecedented demand shock in the global oil markets due to COVID-19, with a slow improvement during the remainder of 2020. The change in the WTI:AWB differential at Edmonton and the USGC during the year ended December 31, 2020 reflected prevailing demand/supply fundamentals for heavy oil and egress constraints moving beyond western Canada.

During the year ended December 31, 2020, the cost of diluent increased by $2.34 per barrel, or 29%, compared to the same period of 2019. The increase reflects wider WTI:AWB differentials at the USGC and the use of higher priced diluent from inventory, both of which result in a lower recovery of the cost of diluent through blend sales. The Corporation's diluent is sourced from Edmonton and Mont Belvieu, Texas. Included in the cost of diluent are transportation costs to move diluent purchases from Mont Belvieu to the Edmonton area. These transportation costs are included in the total diluent cost of $61.86 per barrel of diluent for the year ended December 31, 2020 compared to $79.89 per barrel of diluent for 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.

	2020		2019	
($millions, except as indicated)		$/bbl		$/bbl
Transportation and storage	**$ (391)**	**$ (12.92)**	$ (370)	$ (10.84)
Bitumen sales volumes - bbls/d		**82,722**		93,587

During the year ended December 31, 2020, total transportation and storage costs increased by 6% compared to the same period of 2019. The increase is primarily the result of additional transportation costs associated with the increased capacity on FSP beginning in July 2020 combined with lower apportionment levels partially offset by the elimination of delivered rail transportation costs to the USGC.

Beginning in 2020, the Corporation suspended its transport of blend sales by rail on a delivered basis to the USGC in favour of increasing its blend sales freight on board ("FOB") at rail terminals in the Edmonton area. The Corporation no longer leases rail cars nor has contracted rail commitments beyond loading capacity of FOB sales in the Edmonton area. The Corporation's commitment to move barrels to USGC refineries via FSP increased from 50,000 bbls/d to 100,000 bbls/d in July 2020, subject to apportionment on the Enbridge mainline.

Transportation and storage costs on a per barrel basis increased during the year ended December 31, 2020, compared to the same period of 2019, as increased fixed costs were allocated over lower sales volumes.

The Corporation executed on its strategy to partially mitigate the cost of unutilized transportation and storage assets through the purchase and sale of non-proprietary product. These activities added $37 million, or $0.86 per barrel to blend sales, during the year ended December 31, 2020 compared to $15 million, or $0.31 per barrel to blend sales, during the same period of 2019. This increase in blend sales directly mitigates the increase in transportation expense seen during 2020. The Corporation does not engage in speculative trading. The purchase and sale of third-party products requires the elimination 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. To the extent that marketing asset capacity is underutilized, the Corporation has and will continue to look to mitigate these costs through short and medium-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.

	2020		2019	
($millions, except as indicated)		$/bbl		$/bbl
Royalties	**$ (9)**	**$ (0.31)**	$ (45)	$ (1.30)

The decrease in royalties for the year ended December 31, 2020, compared to the same period of 2019, is 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 Alberta electrical grid displaces other power sources that have a higher carbon intensity, thereby reducing the Corporation's carbon footprint.

	2020		2019	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Operating costs - non-energy	**$ (133)**	**$ (4.38)**	$ (157)	$ (4.61)
Operating costs - energy	**(99)**	**(3.29)**	(81)	(2.38)
Power revenue	**45**	**1.49**	60	1.75
Net operating costs	**$ (187)**	**$ (6.18)**	$ (178)	$ (5.24)
Average natural gas purchase price (C$/mcf)		**$ 2.72**		$ 2.18
Average realized power sales price (C$/Mwh)		**$ 47.81**		$ 56.70

Non-energy operating costs decreased for the year ended December 31, 2020, compared to the same period of 2019. Throughout 2020, the Corporation has taken measures to reduce costs through reductions in staffing levels as well as temporary salary rollbacks, and vendor concessions. Also contributing to the decrease were various government led initiatives to assist the industry through unprecedented market volatility. In response to the serious economic impacts of COVID-19, resulting in the collapse of oil prices and the impact on the oil and gas industry, the federal government took steps to provide various subsidy programs and the provincial and municipal governments have provided relief by reducing regulatory monitoring costs and taxes. During the year ended December 31, 2020, the Corporation was able to benefit from non-recurring cost reductions of $13 million.

Total net energy operating costs increased for the year ended December 31, 2020, compared to the same period of 2019, predominantly due to the AECO natural gas market strengthening and the Alberta power market softening.

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.

	2020		2019	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Realized gain (loss) on commodity risk management	**$ 343**	**$ 11.34**	$ (113)	$ (3.31)

Realized gains recognized on commodity risk management contracts have significantly increased during the year ended December 31, 2020, compared to 2019 mainly due to the unprecedented decline in the WTI price primarily in the first half of 2020 compared to the WTI fixed price contracts in place. Realized losses were recognized during the year ended December 31, 2019. Refer to the commodity risk management discussion within the "OTHER OPERATING RESULTS" section of this MD&A for further details.

Marketing Activity

The following tables summarize the Corporation's blend sales, net of transportation and storage at Edmonton by sales market for the years 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:

	2020			
	Edmonton (US$/bbl)		USGC (US$/bbl)	TOTAL (US$/bbl)
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline[3][4]	
WTI - benchmark	$ 39.40	$ 39.40	$39.40	$ 39.40
Differential - WTI:AWB at sales point	(17.59)	(17.92)	(1.92)	(11.33)
Blend sales price	21.81	21.48	37.48	28.07
Transportation and storage[1]	(1.99)	(4.98)	(12.74)	(6.74)
Transportation and storage from Christina Lake to Edmonton[2]	1.99	1.99	1.99	1.99
Blend sales price, net of transportation & storage at Edmonton	$ 21.81	$ 18.49	$26.73	$ 23.32
Total blend sales - bbls/d	53,831	16,865	47,651	118,347
% of total sales	46 %	14 %	40%	100 %

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 21.74	$ 37.48	$ 15.74
Transportation and storage[1]	(2.70)	(12.74)	(10.04)
Transportation and storage from Christina Lake to Edmonton[2]	1.99	1.99	—
Blend sales price, net of transportation & storage at Edmonton	$ 21.03	$ 26.73	$ 5.70

	2019				
	Edmonton (US$/bbl)		USGC (US$/bbl)		TOTAL (US$/bbl)
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline[3]	Rail	
WTI - benchmark	$ 57.03	$ 57.03	$ 57.03	$ 57.03	$ 57.03
Differential - WTI:AWB at sales point	(15.88)	(11.52)	(1.28)	(3.78)	(10.84)
Blend sales price	41.15	45.51	55.75	53.25	46.19
Transportation and storage[1]	(1.71)	(4.28)	(10.67)	(23.54)	(5.70)
Transportation and storage from Christina Lake to Edmonton[2]	1.71	1.71	1.71	1.71	1.71
Blend sales price, net of transportation & storage at Edmonton	$ 41.15	$ 42.94	$ 46.79	$ 31.42	$ 42.20
Total blend sales - bbls/d	78,421	11,459	36,116	8,227	134,223
% of total sales	58 %	9 %	27 %	6 %	100 %

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

(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$12.92 per barrel for the year ended December 31, 2020 compared to C$10.84 per barrel for the year ended December 31, 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. During the year ended December 31, 2020 these activities contributed US$1.61 per barrel to the blend sales price at the USGC (pipeline) compared to US$0.89 during the same period of 2019. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC (pipeline) during the year ended December 31, 2020 would be US$11.13 per barrel compared to US$12.74 per barrel and the WTI:AWB differential at the USGC (pipeline) would be US$3.53 per barrel compared to US$1.92 per barrel. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC (pipeline) during the year ended December 31, 2019 would be US$9.78 per barrel compared to US$10.67 per barrel and the WTI:AWB differential at the USGC (pipeline) would be US$2.17 per barrel compared to US$1.28 per barrel.*

(4) *Includes 568 bbls/d of blend sales transported to the USGC via rail. USGC rail was suspended during the first quarter of 2020.*

(5) *Results are translated at the average foreign exchange rate of 1.3413 for the year ended December 31, 2020 and 1.3269 for the year ended December 31, 2019.*

Excluding transportation and storage costs upstream of the Edmonton market, the Corporation's net AWB blend sales price averaged US$23.32 per barrel during the year ended December 31, 2020 compared to the posted AWB benchmark price at Edmonton of US$25.08 per barrel. This is largely the result of increased sales exposure to the Edmonton market due to higher levels of apportionment in the first quarter of 2020 which preceded the Corporation's increased FSP transportation commitment. Also impacting the blend sales price year-to-date is the wider fixed differential on Edmonton blend sales compared to the benchmark WTI:AWB differential at Edmonton.

Effective July 1, 2020, the Corporation's contracted transportation capacity on FSP increased from 50,000 bbls/d to 100,000 bbls/d. 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 a premium earned on blend sales at the USGC over the Edmonton market of US$5.70 per barrel for the year ended December 31, 2020. This compares to a premium of US$2.57 per barrel at the USGC compared to the Edmonton market during the same period of 2019. The increased premium, compared to the same period of 2019, is primarily due to an increased portion of volumes being sold at the USGC via pipeline (40% compared to 27% for the same period of 2019) as well as the suspension of delivered USGC rail activity in early 2020.

Revenue

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

($millions)		**2020**		**2019**
Sales from:				
Production	**$**	**1,594**	$	2,996
Purchased product[(1)]		**650**		907
Petroleum revenue	**$**	**2,244**	$	3,903
Royalties		**(9)**		(45)
Petroleum revenue, net of royalties	**$**	**2,235**	$	3,858
Power revenue	**$**	**45**	$	60
Transportation revenue		**12**		13
Other revenue	**$**	**57**	$	73
Total revenues	**$**	**2,292**	$	3,931

(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 year ended December 31, 2020, total revenues decreased 42% from the same period of 2019 primarily as a result of the decrease to the average blend sales price driven by the decline in WTI prices, the widening of the WTI:AWB differential at the USGC as the Corporation sold more barrels into the USGC during the second half of 2020 and a 12% reduction in blend sales volumes primarily as a result of turnaround activities from June to August 2020.

Net Loss

($millions, except per share amounts)		**2020**		**2019**
Net loss	**$**	**(357)**	$	(62)
Per share, diluted	**$**	**(1.18)**	$	(0.21)

The Corporation incurred a net loss for the year ended December 31, 2020 of $357 million compared to a net loss of $62 million during the same period of 2019 largely driven by the impact of lower oil prices on the Corporation's cash operating netback. Significant non-cash items also impacted the increase in the net loss which included a $366 million exploration expense associated with certain non-core assets and a decrease in the unrealized foreign exchange gain driven by the strengthening of the Canadian dollar. These were partially offset by an unrealized commodity risk management gain as a result of weaker forward commodity prices compared to an unrealized commodity risk management loss in the same period of 2019.

Capital Expenditures

($millions)		2020		2019
Sustaining and maintenance	**$**	**105**	$	115
Turnaround		**25**		—
Phase 2B brownfield expansion		**14**		46
eMVAPEX		**11**		28
Field infrastructure, corporate and other		**3**		24
	$	**158**	$	213
eMVAPEX goverment grant		**(9)**		(15)
	$	**149**	$	198

The decrease in capital spending for the year ended December 31, 2020, compared to the same period of 2019, reflects the Corporation's decision to reduce capital spending in 2020 due to the unprecedented negative oil price environment experienced in each of March, April and May of 2020 when reductions in the Corporation's planned capital program were announced. Approximately 80% of the reductions were deferred to the Corporation's 2021 capital budget. Phase 2B brownfield expansion expenditures were suspended at the end of the first quarter of 2020 in response to market conditions at the time.

Capital expenditures during the year ended December 31, 2020 primarily consisted of sustaining and maintenance activities and the 75-day turnaround that began in early June 2020 and was completed in August 2020. The 2020 turnaround was extended in duration and expanded in scope, relative to base budget, in order to minimize staff levels at site during COVID-19 and maximize utilization of the Corporation's internal resources thereby lowering overall cash costs. The Corporation also made the decision to advance turnaround activities from 2021 to capitalize on the low oil price environment and to reduce the 2021 turnaround requirements.

6. OUTLOOK

The Corporation's 2020 annual results were in line with the Corporation's most recent capital guidance update.

Summary of 2020 Guidance	Original Guidance (November 21, 2019)	**Revised Guidance (December 7, 2020)(1)**	**Annual Results**
Production (annual average)	94,000-97,000 bbls/d	82,250 - 82,500 bbls/d	82,441 bbls/d
Non-energy operating costs	$4.50-$4.90 per bbl	$4.30-$4.40 per bbl	$4.38 per bbl
G&A expense	$1.75-$1.85 per bbl	$1.55-$1.60 per bbl	$1.62 per bbl
Capital expenditures	$250 million	$150 million	$149 million

(1) Revised non-energy operating costs and G&A expense guidance ranges include approximately $15 million ($0.50 per bbl) and $7 million ($0.25 per bbl), respectively, of temporary cost reductions.

As a result of the significant commodity price volatility and unstable global economic atmosphere during 2020, the Corporation's guidance was revised from the original guidance five times during the year in response to changing market conditions. The most significant adjustment made was to the capital expenditures, which were reduced by $100 million from the original budget of $250 million. The original planned capital spending was deferred from 2020 to 2021 and consisted mainly of additional well capital to increase production. As a result of the reduced capital spending, as well as voluntary production curtailments in the spring, the 2020 production guidance was reduced by about 13,000 bbls/d over the course of the year.

On December 7, 2020 the Corporation released its 2021 capital and operating budget.

Summary of 2021 Guidance[(1)]	
Bitumen production - annual average	86,000-90,000 bbls/d
Non-energy operating costs	$4.60-$5.00 per bbl
G&A expense	$1.70-$1.80 per bbl
Capital expenditures	$260 million

(1) 2021 guidance does not include any potential benefit which may be received in 2021 from government COVID-related assistance payments.

MEG expects full year 2021 total transportation costs to average between US$7.75 to US$8.25 per barrel of AWB blend sales.

7. BUSINESS ENVIRONMENT

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

	Year ended December 31		**2020**				**2019**			
	2020	**2019**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Average Benchmark Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**43.22**	64.18	**45.25**	43.39	33.30	50.95	62.50	61.97	68.32	63.90
WTI (US$/bbl)	**39.40**	57.03	**42.66**	40.93	27.85	46.17	56.96	56.45	59.82	54.90
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.60)**	(12.76)	**(9.30)**	(9.09)	(11.47)	(20.53)	(15.83)	(12.24)	(10.67)	(12.29)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(14.32)**	(14.95)	**(10.56)**	(10.48)	(13.44)	(22.78)	(18.44)	(14.52)	(12.32)	(14.50)
AWB – Edmonton (US$/bbl)	**25.08**	42.08	**32.10**	30.45	14.41	23.39	38.52	41.93	47.50	40.40
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(4.77)**	(1.77)	**(2.83)**	(3.20)	(7.29)	(5.74)	(5.25)	(2.50)	1.64	(0.89)
AWB – U.S. Gulf Coast (US$/bbl)	**34.63**	55.26	**39.83**	37.73	20.56	40.43	51.71	53.95	61.46	54.01
Condensate prices										
Condensate at Edmonton (C$/bbl)	**49.48**	70.19	**55.39**	50.03	30.72	61.76	70.01	68.73	74.76	67.25
Condensate at Edmonton as % of WTI	**93.6%**	92.8%	**99.6%**	91.8%	79.6%	99.5%	93.1%	92.2%	93.4%	92.1%
Condensate at Mont Belvieu, Texas (US$/bbl)	**32.18**	48.24	**38.52**	33.52	17.43	39.27	50.08	44.34	50.22	48.31
Condensate at Mont Belvieu, Texas as % of WTI	**81.7%**	84.6%	**90.3%**	81.9%	62.6%	85.1%	87.9%	78.5%	84.0%	88.0%
Natural gas prices										
AECO (C$/mcf)	**2.43**	1.92	**2.88**	2.48	2.21	2.26	2.70	0.95	1.12	2.86
Electric power prices										
Alberta power pool (C$/MWh)	**46.53**	55.28	**46.05**	43.75	29.94	66.38	47.07	46.95	56.37	70.73
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.3413**	1.3269	**1.3031**	1.3316	1.3860	1.3445	1.3201	1.3207	1.3376	1.3293
C$ equivalent of 1 US$ – period end	**1.2755**	1.2965	**1.2755**	1.3324	1.3616	1.4120	1.2965	1.3244	1.3091	1.3360

Beginning in early March 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 into the second half of 2020 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 the quality difference 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"). The Curtailment Rules came into force on January 1, 2019 and remain in place until December 31, 2021. The Curtailment Rules give the Province of Alberta the authority to make an Order to set the maximum combined provincial production amount of crude oil and bitumen on a monthly basis. The intent of the production limits is to align production with export capacity, protecting the value of the province's oil by helping prevent Canadian crude from selling at large discounts. Production limits were in place from January 2019 through November 2020. Although the Curtailment Rules remain in effect, production limits were suspended beginning in December 2020 and companies are now allowed to produce at their discretion.

On October 31, 2019 the Government of Alberta Special Production Allowance ("SPA") program was enacted to give crude oil and bitumen producers temporary curtailment relief equal to incremental increases in rail shipments. On a monthly basis, operators can apply to increase oil production if additional product is moved by new rail capacity out of the province. This program came into force on December 1, 2019 and remains in effect concurrent with the Curtailment Rules. The Corporation benefited from utilization of the SPA program during portions of 2020 and is positioned to do so again should production limits be reintroduced.

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 both the Edmonton area and the USGC, where pricing is generally lower. The Corporation has committed diluent purchases of 20,000 bbls/d at the USGC reference benchmark pricing at Mont Belvieu, Texas.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, used as fuel to generate steam for the thermal production process and to create steam and electricity from the Corporation's cogeneration facilities. The AECO natural gas price increased during the year ended December 31, 2020 compared to the same period of 2019 due to market uncertainty surrounding possible gas supply constraints in 2021.

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 year ended December 31, 2020 compared to the same period of 2019 primarily as a result of an oversupply of generation in the province.

8. OTHER OPERATING RESULTS

Depletion and Depreciation

($millions, except as indicated)		2020		2019
Depletion and depreciation expense	**$**	**410**	$	710
Depletion and depreciation expense per barrel of production	**$**	**13.60**	$	20.90

Depletion and depreciation expense decreased in 2020 as a result of the accelerated depreciation expense taken in 2019 due to the Corporation narrowing its development focus to core assets at Christina Lake. The Corporation incurred an accelerated depreciation expense of $13 million, or $0.43 per barrel, during the year ended December 31, 2020 compared to an accelerated depreciation expense of $237 million, or $6.98 per barrel, for the year ended December 31, 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 $13.17 per barrel for the year ended December 31, 2020 compared to $13.92 per barrel for the year ended December 31, 2019. Depletion and depreciation expense per barrel decreased due to lower average future development costs and reductions in other depreciable costs primarily as a result of the accelerated depreciation recognized on equipment, materials and engineering costs in 2019.

Exploration Expense

($millions)		2020	2019
Exploration expense	**$**	**366**	58

During the first quarter of 2020, the Corporation discontinued exploration and evaluation activities in certain non-core growth properties as it narrows the development focus to core assets at Christina Lake. The associated land lease and evaluation costs totaling $366 million were charged to exploration expense compared to $58 million during 2019.

Commodity Risk Management Gain (Loss)

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

($millions)		2020		2019
Realized:				
Crude oil contracts(1)	**$**	**359**	$	(89)
Condensate contracts(2)		**(16)**		(24)
Realized commodity risk management gain (loss)	**$**	**343**	$	(113)
Unrealized:				
Crude oil contracts(1)	**$**	**(13)**	$	(170)
Condensate contracts(2)		**66**		1
Natural gas contracts(3)		**(4)**		—
Unrealized commodity risk management gain (loss)	**$**	**49**	$	(169)
Commodity risk management gain (loss)	**$**	**392**	$	(282)

(1) *Includes WTI fixed price contracts, WTI enhanced fixed price with sold put options contracts and WTI:WCS fixed differential contracts.*
(2) *Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas relative to WTI.*
(3) *Relates to contracts which fix the AECO price on natural gas purchases.*

For the year ended December 31, 2020, the Corporation recognized a $392 million net gain from commodity risk management primarily due to gains on settlement of WTI fixed price contracts during the first half of 2020, when actual WTI prices were weaker than contracted prices. These gains were partially offset by losses on WTI:WCS fixed differential contracts, as actual differentials narrowed relative to contracted prices for the June to December period. This compares with the $282 million net loss from commodity risk management for the year ended December 31, 2019, when gains from weaker WTI prices as compared to contracted prices were more than offset by losses from narrower WTI:WCS differentials as compared 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):

(US$/bbl)		**2020**		**2019**
WTI fixed price contracts[1]:				
Average fixed price	**$**	**51.18**	$	62.13
Average settlement price		**39.58**		57.12
Gain (loss) on WTI fixed price contracts	**$**	**11.60**	$	5.01
WTI:WCS fixed differential contracts:				
Average fixed differential	**$**	**(20.15)**	$	(21.69)
Average settlement differential		**(11.90)**		(12.76)
Gain (loss) on WTI:WCS fixed differential contracts	**$**	**(8.25)**	$	(8.93)
Condensate purchase contracts:				
Average fixed differential[2]	**$**	**(5.54)**	$	(5.19)
Average settlement differential		**(7.63)**		(8.81)
Gain (loss) on condensate purchase contracts	**$**	**(2.09)**	$	(3.62)

(1) *Excludes enhanced fixed price with sold put options contracts which realized an average gain of US$7.22 per barrel.*
(2) *Condensate purchase contracts either fix the WTI:condensate differential at Mont Belvieu, Texas relative to WTI or fix the condensate price as a % of WTI.*

General and Administrative

($millions, except as indicated)		**2020**		**2019**
General and administrative	**$**	**49**	$	68
General and administrative expense per barrel of production	**$**	**1.62**	$	1.99

G&A expense decreased 28% for the year ended December 31, 2020 compared to the same period of 2019. Contributing to the decrease was the Corporation's continuing efforts to drive efficiency into its cost structure including reductions in staffing levels as well as temporary salary rollbacks, vendor concessions and various government led initiatives to assist the industry through unprecedented market volatility. During the year ended December 31, 2020, the Corporation was able to benefit from non-recurring G&A expense reductions of approximately $6 million.

In response to initial market volatility and the impact of COVID-19 on the Corporation's cash flow, a decision was made to temporarily 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. The rollbacks remained in place for six months of 2020, ending on November 30, 2020.

Stock-based Compensation

($millions)		**2020**		2019
Cash-settled expense	**$**	**1**	$	7
Equity-settled expense		**11**		24
Equity price risk management gain[1]		**(26)**	$	—
Stock-based compensation	**$**	**(14)**	$	31

(1) Relates to financial derivatives entered into to manage the Corporation's exposure to cash-settled restricted share units ("RSUs") and performance share units ("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 decrease in cash-settled expense was primarily due to the decline in the Corporation's share price. The Corporation's common share price declined to $4.45 per share as at December 31, 2020, from its value of $7.39 per share as at December 31, 2019, primarily due to the impact of COVID-19 on capital markets.

Equity-settled stock-based compensation expense decreased for the year ended December 31, 2020, compared to the same period of 2019, due to a decrease in the value of awards granted in 2020 and recoveries as a result of staff reductions. 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%.

The equity price risk management (gain) loss is driven by the change in the Corporation's common share price relative to the notional value of the instruments. For the year ended December 31, 2020, an unrealized gain of $26 million was recognized on the increase in share price since inception in March 2020.

Foreign Exchange Gain (Loss), Net

($millions)		**2020**		2019
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$**	**36**	$	180
US$ denominated cash and cash equivalents		**11**		(8)
Unrealized net gain (loss) on foreign exchange		**47**		172
Realized gain (loss) on foreign exchange		**2**		3
Foreign exchange gain (loss), net	**$**	**49**	$	175

C$ equivalent of 1 US$		
Beginning of period	**1.2965**	1.3646
End of period	**1.2755**	1.2965

The Corporation's foreign exchange gain (loss) is driven by fluctuations in the U.S. dollar to Canadian dollar exchange rate. The primary driver of the Corporation's foreign exchange gain (loss) is the Corporation's long-term debt which is denominated in U.S. dollars.

For the year ended December 31, 2020, the Canadian dollar strengthened relative to the U.S. dollar by 2%, resulting in an unrealized foreign exchange gain of $47 million. For the year ended December 31, 2019, the Canadian dollar strengthened by 5%, resulting in an unrealized foreign exchange gain of $172 million.

Net Finance Expense

($millions)		2020		2019
Interest expense on long-term debt	**$**	**241**	$	267
Interest expense on lease liabilities		**26**		26
Interest income		**(3)**		(5)
Net interest expense		**264**		288
Debt extinguishment expense[(1)(2)]		**12**		46
Accretion on provisions		**8**		7
Unrealized loss on derivative financial liabilities		**—**		(1)
Net finance expense	**$**	**284**	$	340
Average effective interest rate		**6.9%**		6.6%

(1) For the year ended December 31, 2020, debt extinguishment expense related to the refinancing of the 7.00% senior unsecured notes due March 2024 included a cumulative debt redemption premium of $9 million and associated unamortized deferred debt issue costs of $3 million. Refer to Note 10 of the 2020 audited annual consolidated financial statements for further details.

(2) For the year ended December 31, 2019, debt extinguishment expense included a cumulative debt redemption premium of $29 million and associated unamortized deferred debt issue costs of $10 million as well as a $4 million premium paid on the repurchase of the senior secured second lien notes and related unamortized deferred debt issue costs of $3 million. Refer to Note 10 of the 2020 audited annual consolidated financial statements for further details.

Other Expenses

($millions)		2020		2019
Contract cancellation	**$**	**33**	$	—
Onerous contract expense		**25**		—
Severance and restructuring		**10**		11
Research and development		**—**		12
Other expenses	**$**	**68**	$	23

Contract cancellation costs were incurred to mitigate rail sales contract exposure. The economic decision to divert sales volumes from rail contracts at Edmonton to the USGC more than recovered the cost of contract cancellations.

Onerous contract expense is the total future cash flows related to the Corporation's onerous marketing contract recognized at December 31, 2020.

Income Tax

($millions)		2020		2019
Income tax expense (recovery)	**$**	**(120)**	$	(29)
Effective tax rate		**25 %**		32 %

As at December 31, 2020, the Corporation had approximately $7.4 billion of available Canadian tax pools and recognized a deferred income tax asset of $382 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

The effective tax rate of 25% for the year ended December 31, 2020 is higher than the Canadian statutory rate of 24% primarily due to the tax effect of realized and unrealized foreign exchange losses on the Corporation's debt.

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

On June 28, 2020, the Government of Alberta further announced a proposal to accelerate the previous corporate tax rate reduction and reduce the corporate tax rate in 2020 from 10% to 8%, effective July 1, 2020, which became enacted in the fourth quarter of 2020. As the Corporation had previously revalued its deferred tax asset at the reduced Alberta tax rate of 8% the rate reduction had no further impact to the Corporation's deferred tax position.

9. SUMMARY OF ANNUAL INFORMATION

($millions, except per share amounts)	**2020**	**2019**	**2018**
Revenue[1]	**$ 2,292**	**$ 3,931**	$ 2,733
Net loss	**(357)**	**(62)**	(119)
Per share - basic and diluted	**(1.18)**	**(0.21)**	(0.40)
Total assets	**7,224**	**7,866**	8,410
Total non-current liabilities	**3,276**	**3,455**	4,058

(1) The total of petroleum revenue, including the sale of third-party products related to marketing asset optimization activity, net of royalties and other revenue as presented on the Consolidated Statement of Earnings and Comprehensive Income.

Revenue

During 2020 revenue decreased 42% from 2019 primarily as a result of the 39% decrease in the average blend sales price and 12% decrease in blend sales volumes. The decrease in average blend sales price was driven by a lower WTI price and a wider WTI:AWB differential at the USGC in 2020 compared to 2019.

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

Net Loss

The Corporation recognized a net loss of $357 million in 2020 compared to a net loss of $62 million in 2019 largely driven by the impact of lower oil prices on the Corporation's cash operating netback. Significant non-cash items also impacted the increase in the net loss which included a $366 million exploration expense associated with certain non-core assets and a decrease in the unrealized foreign exchange gain driven by the Canadian dollar strengthening less in 2020. These were partially offset by an unrealized commodity risk management gain as a result of weaker forward commodity prices compared to an unrealized commodity risk management loss in the same period of 2019.

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

Total Assets

Total assets at December 31, 2020 decreased compared to December 31, 2019, mainly as a result of discontinued exploration and evaluation activities in certain non-core growth properties and the associated land lease and evaluation costs totaling $366 million, which was charged to exploration expense, as well as a result of depletion and depreciation charges that were in excess of capital expenditures.

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

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

Total Non-Current Liabilities

Total non-current liabilities as at December 31, 2020 decreased compared to December 31, 2019 primarily due to the repayment of long-term debt totaling $132 million. During 2020, the Corporation repurchased and extinguished a portion of its 6.5% senior secured second lien notes.

Total non-current liabilities as at December 31, 2019 decreased compared to December 31, 2018 primarily due to the repayment of long-term debt totaling $501 million. During 2019, the Corporation fully repaid the outstanding senior secured term loan balance and repurchased and extinguished a portion of its 6.5% senior secured second lien notes.

10. LIQUIDITY AND CAPITAL RESOURCES

($millions)	**December 31, 2020**	December 31, 2019
Second Lien:		
6.5% senior secured second lien notes[d] (December 31, 2020 - US$496 million; December 31, 2019 - US$596 million; due 2025)	**$ 633**	$ 773
Unsecured:		
7.0% senior unsecured notes[b] (December 31, 2020 - US$600 million; December 31, 2019 - US$1 billion; due 2024)	**765**	1,297
7.125% senior unsecured notes[a] (December 31, 2020 - US$1.2 billion; December 31, 2019 - US$nil; due 2027)	**1,531**	—
6.375% senior unsecured notes[c] (December 31, 2020 - US$nil; December 31, 2019 - US$800 million; due 2023)	**—**	1,037
Less:		
Debt redemption premium	**9**	29
Unamortized deferred debt discount and debt issue costs	**(26)**	(13)
Long-term debt	**2,912**	3,123
Cash and cash equivalents	**(114)**	(206)
Net debt[1]	**$ 2,798**	$ 2,917

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

During the year ended December 31, 2020 net debt decreased by $119 million due to the partial redemption of the Corporation's 6.5% senior secured second lien notes and the strengthening of the Canadian dollar relative to the U.S. dollar, partially offset by the decrease in cash and cash equivalents.

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.

Subsequent to December 31, 2020, on February 2, 2021, the Corporation successfully closed a private offering of US$600 million in aggregate principal amount of 5.875% senior unsecured notes due February 2029. The net proceeds of the offering, together with cash-on-hand, were used to fully redeem US$600 million in aggregate principal amount of its 7.00% senior unsecured notes due March 2024 at a redemption price of 101.167% and to pay fees and expenses related to the offer.

The Corporation's cash and cash equivalents balance was $114 million as at December 31, 2020 compared to $206 million as at December 31, 2019. Adjusted funds flow of $278 million during the year ended December 31, 2020 was more than offset by the repayment of debt and capital expenditures. Refer to the "Cash Flow Summary" section for further details.

The Corporation has total available credit under two facilities of $1.3 billion, comprised of $800 million under the revolving credit facility and $500 million under 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 revolving credit facility, EDC facility and senior secured second lien notes are secured by substantially all the assets of the Corporation.

The Corporation proactively responded to the changing economic environment throughout 2020. As a result of the significant commodity price volatility and unstable global economic atmosphere during 2020, the Corporation's 2020 guidance was revised from the original guidance five times during the year in response to changing market conditions. Meeting current and future obligations while navigating the uncertainty associated with COVID-19 was, and continues to be supported by the Corporation's financial framework including a strong commodity risk management program securing cash flow through 2020 and extending into 2021, 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$496 million of senior secured second lien notes due January 2025. 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. None of the Corporation's outstanding long-term debt contain financial maintenance covenants and none are secured on a *pari passu* basis with the credit facility.

As at December 31, 2020, the Corporation had $785 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $100 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 year ended December 31, 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

	Year ended December 31	
($millions)	**2020**	**2019**
Net cash provided by (used in):		
Operating activities	**$ 302**	$ 631
Investing activities	**(189)**	(211)
Financing activities	**(216)**	(523)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**11**	(9)
Change in cash and cash equivalents	**$ (92)**	$ (112)

Cash Flow – Operating Activities

Net cash provided by operating activities for the year ended December 31, 2020 decreased compared to the same period of 2019, 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 decreased during the year ended December 31, 2020 compared to 2019 which aligns with the Corporation's reduced capital spending.

Cash Flow – Financing Activities

Net cash used in financing activities during the year ended December 31, 2020 included the redemption of a portion of the 6.5% senior secured second lien notes totaling $132 million (US$100 million) as well as debt redemption premiums and other refinancing costs incurred related to the January 31, 2020 refinancing. Net cash used in financing activities for the year ended December 31, 2019 consisted primarily of the repayment of the outstanding senior secured term loan balance of $297 million (US$225 million) and the repurchase and extinguishment of a portion of its 6.5% senior secured second lien notes totaling $204 million (US$154 million).

11. 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, condensate purchases, natural gas purchases and power sales. 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, condensate purchases and natural gas purchases outstanding as at December 31, 2020:

As at December 31, 2020			
Crude Oil Sales (Purchase) Contracts	**Volumes (bbls/d)(1)**	**Term**	**Average Price (US$/bbl)(1)**
WTI Fixed Price	21,200	Jan 1, 2021 - Mar 31, 2021	$46.73
WTI Fixed Price	13,000	Apr 1, 2021 - Jun 30, 2021	$46.31
WTI:WCS Fixed Differential	968	Jan 1, 2021 - Jan 31, 2021	$(10.90)
WTI:WCS (USGC) Fixed Differential	(1,071)	Feb 1, 2021 - Feb 28, 2021	$(2.50)
Enhanced Fixed Price with Sold Put Option			
WTI Fixed Price/Sold Put Option Strike Price	29,000	Jan 1, 2021 - Dec 31, 2021	$46.18/$38.79
Condensate Purchase Contracts			
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	$(11.30)
Natural Gas Purchase Contracts	**Volumes (GJ/d)(1)**	**Term**	**Average Price (C$/GJ)(1)**
AECO Fixed Price	38,733	Jan 1, 2021 - Dec 31, 2021	$2.60

(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 December 31, 2020 and March 3, 2021:

Subsequent to December 31, 2020			
Crude Oil Sales Contracts	**Volumes (bbls/d)(1)**	**Term**	**Average Price (US$/bbl)(1)**
WTI Fixed Price	16,161	Jan 1, 2021 - Mar 31, 2021	$50.35
WTI:WCS Fixed Differential	15,000	Mar 1, 2021 - Mar 31, 2021	$(13.62)
WTI:WCS Fixed Differential	28,000	Apr 1, 2021 - Jun 30, 2021	$(12.26)
WTI:WCS Fixed Differential	4,000	Jul 1, 2021 - Sep 30, 2021	$(11.18)

(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 December 31, 2020:

Commodity	**Sensitivity Range**	**Increase**	**Decrease**
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	**$ (84)**	**$ 80**
Condensate purchase price	± 5% in condensate price as a percentage of WTI	**$ 13**	**$ (13)**
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	**$ 11**	**$ (11)**

The Corporation had the following physical commodity risk management contracts relating to crude oil sales, condensate purchases, natural gas purchases and power sales outstanding as at March 3, 2021:

Crude Oil Sales Contracts	Volumes (bbls/d)(1)	Term	Average Price (US$/bbl)(1)
WTI:AWB Fixed Differential	15,000	Feb 1, 2021 - Jun 30, 2021	$(17.65)
Condensate Purchase Contracts			
WTI:Condensate Fixed Differential	4,490	Jan 1, 2021 - Dec 31, 2021	$(1.29)
Natural Gas Purchase Contracts	**Volumes (GJ/d)(1)**	**Term**	**Average Price (C$/GJ)(1)**
AECO Fixed Price	7,500	Jan 1, 2021 - Dec 31, 2021	$2.71
Power Sales Contracts	**Quantity (MWh)(1)**	**Term**	**Average Price (C$/MW)(1)**
Fixed Price	34	Feb 1, 2021 - Dec 31, 2021	$62.80

(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 entered 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.

12. SHARES OUTSTANDING

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

(millions)	**Units**
Common shares	**302.7**
Convertible securities	
Stock options(1)	**4.7**
Equity-settled RSUs and PSUs	**6.5**

(1) 4.2 million stock options were exercisable as at December 31, 2020.

As at March 2, 2021, the Corporation had 302.7 million common shares, 4.6 million stock options and 6.5 million equity-settled RSUs and equity-settled PSUs outstanding, and 4.2 million stock options exercisable.

13. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations as at December 31, 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)	2021	2022	2023	2024	2025	Thereafter	Total
Commitments:							
Transportation and storage[1]	$ 397	$ 411	$ 454	$ 440	$ 413	$ 5,598	$ 7,713
Diluent purchases	152	21	17	—	—	—	190
Other operating commitments	24	16	16	13	13	36	118
Variable office lease costs	4	4	4	5	5	26	48
Capital commitments	12	—	—	—	—	—	12
Total Commitments	589	452	491	458	431	5,660	8,081
Other Obligations:							
Lease obligations	73	41	36	35	28	491	704
Long-term debt[2]	—	—	—	765	633	1,531	2,929
Interest on long-term debt[2]	204	204	204	164	112	122	1,010
Decommissioning obligation[3]	4	4	5	4	4	781	802
Obligations	**$ 870**	**$ 701**	**$ 736**	**$ 1,426**	**$ 1,208**	**$ 8,585**	**$ 13,526**

(1) *This represents transportation and storage commitments from 2021 to 2048, including pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet.*

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

14. 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 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.

15. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting policies and estimates are those estimates having a significant impact on the Corporation's financial position and operations and that require management to make judgments, assumptions and estimates in the application of IFRS. Judgments, assumptions and estimates are based on historical experience and other factors that management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgments, assumptions and estimates may be subject to change. Detailed disclosure of the significant accounting policies and the significant accounting estimates, assumptions and judgments used by the Corporation can be found in Note 3 and Note 4, respectively, of the Corporation's annual consolidated financial statements for the year ended December 31, 2020.

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of 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.

16. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the year ended December 31, 2020 and December 31, 2019, other than compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($millions)	**2020**	2019
Share-based compensation	**$ 6**	$ 19
Salaries and short-term employee benefits	**5**	4
Termination benefits	**—**	1
	$ 11	$ 24

The decrease in share-based compensation to key management personnel in 2020 is mainly due to the decline in the Corporation's share price and its impact on the value of the share-based awards.

17. RISK FACTORS

The Corporation's primary focus is on the ongoing development and operation of its thermal oil assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including among others, operational risks, risks related to economic conditions, environmental and regulatory risks, and financing risks. Many of these risks impact the oil and gas industry as a whole. 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.

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

Risks arising from operations

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

- a decline in oil prices or widening of differentials between various crude oil prices;
- increases in the price applied to carbon emissions;
- the negative impacts of the COVID-19 pandemic and the related global economic downturn;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher SORs, or the inability to recognize continued or increased efficiencies from the Corporation's

production enhancement program which uses a combination of proprietary reservoir technologies (including eMSAGP and eMVAPEX) and processing plant enhancements, debottlenecking and brownfield expansions;

- reduced access to or an increase in the cost of diluent;
- an increase in the cost of natural gas;
- the reliability and maintenance of MEG's facilities;
- the safety and reliability of the Access Pipeline, other pipelines, tankage, railways and railcars and barges that transport MEG's products;
- the need to replace significant portions of existing wells, referred to as "workovers", or the need to drill additional wells;
- the cost to transport bitumen, diluent and bitumen blend, and the cost to dispose of certain by-products;
- the availability and cost of insurance and the inability to insure against certain types of losses;
- severe weather or catastrophic events such as fires, lightning, earthquakes, extreme cold weather, storms or explosions;
- seasonal weather patterns and the corresponding effects of the spring thaw on accessibility to MEG's properties;
- the availability of water supplies and the ability to transmit power on the electrical transmission grid;
- changes in the political landscape and/or legal, tax and regulatory regimes in Canada, the United States and elsewhere;
- the ability to obtain further approvals and permits for MEG's future projects;
- the availability of pipeline capacity and other transportation and storage facilities for MEG's bitumen blend;
- refining markets for MEG's bitumen blend;
- increased royalty payments resulting from changes in regulatory regimes;
- the cost of chemicals used in MEG's operations, including, but not limited to, in connection with water and/or oil treatment facilities;
- the availability of and access to drilling equipment; and
- the cost of compliance with applicable regulatory regimes, including, but not limited to, environmental regulation and Government of Alberta production curtailments, if any.

Status and Stage of Development

While the first three phases of the Christina Lake Project are operational, additional phases and other projects may not be completed on time (or at all), and the costs associated with additional phases may be greater than expected. At a design steam oil ratio of 2.4, MEG has developed oil processing capacity of approximately 100,000 bbls/d at its Christina Lake central plant facility, prior to any impact of scheduled maintenance activity or outages, through the phased construction of the Christina Lake Project as well as several low-cost debottlenecking and expansion projects and the application of its proprietary reservoir technologies. While the investment in Phase 2B brownfield growth project central processing plant is near completion, ramp up in production from the brownfield project, subsequent production enhancement and other projects may not be completed on budget, on time or at all, and the costs associated with additional phases and other projects may be greater than the Corporation expects. In addition, in 2019, MEG opted to request a temporary pause in the regulatory approval process for the May River Regional Project, due to current economic conditions and constrained access to markets.

Additional phases of development of the Christina Lake Project or MEG's other projects may also suffer from delays, cancellations, interruptions or increased costs due to many factors, some of which may be beyond the Corporation's control, including (without limitation):

- future capital expenditures to be made by the Corporation and/or a determination by MEG not to devote capital expenditures to a given project;
- engineering and/or procurement performance falling below expected levels of output or efficiency;
- construction performance falling below expected levels of output or efficiency;
- denial or delays in receipt of regulatory approvals, additional requirements imposed by changes in laws or non-compliance with conditions imposed by regulatory approvals;
- a determination not to proceed with, or to delay, development of a given project;

- labour disputes or disruptions, declines in labour productivity or the unavailability of, or increased cost of, skilled labour;
- increases in the cost of materials;
- changes in project scope or errors in design;
- additional requirements imposed by changes in laws, including environmental laws and regulations;
- the availability of and access to drilling equipment; and
- severe weather or catastrophic events such as fire, earthquakes, extreme cold weather, storms or explosions.

If any of the above events occur, they could have a material adverse effect on the Corporation's ability to continue to develop the Christina Lake Project or other future projects, which would materially adversely affect its business, financial condition, results of operations and prospects. In addition, if any of the Corporation's future phases do not become operational after it has made significant investments therein, the Corporation's operations may not generate sufficient revenue to support its capital structure.

Concentration of Production in Single Project

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

Cybersecurity

The Corporation's operations may be negatively impacted by a cybersecurity incident. MEG uses forms of information technology in its operations and such use creates various cybersecurity threats including the possibility of security breaches, operational disruptions and the release of non-public information (such as financial data, supplier and customer information and employee information). Although MEG has taken various steps to protect itself against such risks, its efforts may not always be successful, especially because of the rapidly changing nature of such cybersecurity threats. Any increase in the number of personnel working remotely in response to the COVID-19 pandemic, may enhance the risks associated with cybersecurity threats. In the event of a cybersecurity incident, MEG's operations could be disrupted resulting in potential loss of customers, violation of laws and additional liabilities to the business.

Risks related to economic conditions

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

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

- the negative impacts of the COVID-19 pandemic and the related global economic downturn;
- global energy policy, including (without limitation) the ability of the Organization of the Petroleum Exporting Countries to set and maintain production levels and influence prices for crude oil;
- political instability and hostilities;
- domestic and foreign supplies of crude oil;
- the overall level of energy demand;
- weather conditions;
- government regulations including curtailment orders;
- taxes;
- currency exchange rates;

- the availability of refining capacity and transportation infrastructure, including pipelines;
- the effect of worldwide environmental and/or energy conservation measures;
- the price and availability of alternative energy supplies; and
- the overall economic environment.

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

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

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

COVID-19 Pandemic and Related Impacts

The COVID-19 pandemic has affected, and may materially and adversely affect, our business, operating and financial results and liquidity. The severity, magnitude and duration of the COVID-19 pandemic remains uncertain and continues to be rapidly changing and hard to predict. While the full impact of this virus and the long-term worldwide reaction to it and impact from it remains unknown at this time, governmental reaction to the pandemic and restrictions and limitations applied by the government as a result, continued widespread growth in infections, travel restrictions, quarantines, or site closures as a result of the virus could, among other things, impact the ability of our employees and contractors to perform their duties, cause increased technology and security risk due to extended and company-wide telecommuting, lead to disruptions in our supply chain (including necessary contractors), increase the risk that oil storage could reach capacity in Canada and the U.S. Gulf Coast as a result of decreased demand, lead to a disruption in our resource acquisition or permitting activities and cause disruption in our relationship with our customers.

Additionally, the COVID-19 pandemic has significantly impacted economic activity and markets around the world, and COVID-19 or another similar outbreak could negatively impact our business in numerous ways, including, but not limited to, the following:

- our revenue may be reduced if the pandemic results in an economic recession, as many experts predict, to the extent it leads to a prolonged decrease in the demand for crude oil, bitumen and bitumen blends;
- our operations may be disrupted or impaired, thus lowering our production level, if a significant portion of our employees or contractors are unable to work due to illness or if our operations are suspended or temporarily shut-down or restricted due to control measures designed to contain the pandemic; and
- our sole operating facility at Christina Lake is subject to risks relating to a temporary suspension or physical interruption of its operations in the event an employee or contractor at our Christina Lake site becomes infected with COVID-19, as it could place our entire site workforce at risk.

In addition, the COVID-19 pandemic has increased volatility and caused negative pressure in the capital and credit markets. As a result, we may experience difficulty accessing the capital or financing needed to fund our operations, which have substantial capital requirements, or refinance our upcoming debt maturities on satisfactory terms or at all. We anticipate funding capital expenditures with existing cash and cash generated by operations (which is subject to a number of variables, including many beyond our control) and, to the extent our capital expenditures exceed our cash resources, from borrowings under our Credit Facility and other external sources of capital, we could be required to curtail our operations and the development of our properties, which in turn could adversely affect our business, results of operations and financial position.

General Economic Conditions, Business Environment and Other Risks

The business of the Corporation is subject to general economic conditions. Adverse changes in general economic and market conditions could negatively impact demand for crude oil, bitumen and bitumen blends, revenue, operating costs, results of financing efforts, timing and extent of capital expenditures, credit risk and counterparty risk.

Volatility in crude oil, bitumen blend, natural gas and diluent prices, fluctuations in interest rates, product supply and demand fundamentals, market competition, labour market supplies, risks associated with technology, risks of a widespread pandemic, the Corporation's ability to generate sufficient cash flow to meet its current and future obligations, the Corporation's ability to access external sources of debt and equity capital, general economic and business conditions, the Corporation's ability to make capital investments and the amounts of capital investments, risks associated with potential future lawsuits and regulations, assessments and audits (including income tax) against the Corporation (and its subsidiaries), political and economic conditions in the geographic regions in which the Corporation and its subsidiaries operate, difficulty or delays in obtaining necessary regulatory approvals, a significant decline in the Corporation's reputation, and such other risks and uncertainties, could individually or in the aggregate have a material adverse impact on the Corporation's business, prospects, financial condition, results of operation or cash flows. Challenging market conditions and the health of the economy as a whole may have a material adverse effect on the Corporation's results of operations, financial condition and prospects. There can be no assurance that any risk management steps taken by the Corporation with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks.

Volatility of Commodity Inputs

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

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

Variations in Foreign Exchange Rates and Interest Rates

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

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

Hedging Strategies

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

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

Global Financial Markets

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

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

Climate Change Risks

Climate change may introduce new risks to the Corporation's business including both physical risks and transitional risks.

Transitional Risks

Transitional risks include a broader set of risks associated with a global transition to a less carbon-intensive economy. A negative impact from transitional risks could result in loss of customers, revenue loss, delays in obtaining regulatory approvals for pipelines and other projects, increased operating, capital, financing or regulatory costs, diminished shareholder confidence, continuing changes to laws and regulations affecting the Corporation’s business or erosion or loss of public support towards the hydrocarbon-based energy sector.

Policy and Legal Risks

Negative consequences which could arise as a result of changes to the current and emerging regulatory environment include, but are not limited to, changes in environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, potentially increasing the cost of construction, operation and abandonment. Policy and legal risks are further discussed under the heading Environmental Considerations below.

Marketing Risks

Negative impacts from transitional risks and physical risks could result in constrained egress out of western Canada which could impact the Corporation's operating results. In terms of reputational risk, negative public perception of the Alberta oil sands could result in delays in obtaining regulatory approvals for pipelines and other projects increasing competition for market access. Future legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil, reduce its price and may result in stranded assets or an inability to further develop oil resources. In terms of physical risk, potential increases in extreme weather events may impede operation of pipelines, storage infrastructure as well as refineries.

Reputational Risks

Reputational risks include numerous factors which could negatively affect the Corporation's reputation, including general public perceptions of the energy industry, negative publicity relating to pipeline incidents, unpopular expansion plans or new projects, opposition from organizations and populations opposed to fossil fuels development, specifically oil sands projects and pipeline projects, including expansions thereof.

Negative public perceptions of the Alberta oil sands, where our thermal oil productions operations are located, may impair the profitability of our current or future oil sands projects.

Development of the Alberta oil sands has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous engagement. The influence of anti-fossil fuels activists (with a focus on oil sands) targeting equity and debt investors, lenders and insurers may result in policies which reduce support for or investment in the Alberta oil sands sector. Concerns about oil sands may, directly or indirectly, impair the profitability of our current oil sands projects, and the viability of future oil sands projects, by creating significant regulatory uncertainty leading to uncertainty in economic modeling of current and future projects and delays relating to the sanctioning of future projects. In addition, evolving decarbonization policies of institutional investors, lenders and insurers could affect the Corporation's ability to access capital pools. Certain insurance companies have taken actions or announced policies to limit available coverage for companies which derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of the Corporation's insurance policies could increase substantially. In some instances, coverage may become unavailable or available only for reduced amounts of coverage. As a result, the Corporation may not be able to extend or renew existing policies, or procure other desirable insurance coverage, either on commercially reasonable terms, or at all.

Technology Risks

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

Technological advancements and innovations associated with the global transition to a less carbon-intensive economy may impact the demand for the Corporation's products. This may include the advancement of alternative energy supplies and carbon performance of petroleum competitors.

Physical Risks

Physical risks associated with climate change may include chronic physical risks such as severe changes to seasonal weather patterns and the corresponding effects of seasonal conditions and temperatures or acute physical risks which include catastrophic events such as fires, lightning, extreme cold weather, or storms, any of which may impact the Corporation's operations.

ESG Related Goals

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

Environmental and Regulatory Risks

Environmental considerations

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

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

All phases of the thermal oil business present environmental risks and hazards and are subject to environmental legislation and regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, permit requirements, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil sands operations and restrictions on water usage and land disruption. The legislation also requires that wells and facility sites be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge.

There has also been increased activism relating to climate change and public opposition to fossil fuels. The federal government and certain provincial governments in Canada have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy, field and emission standards, and alternative energy incentives and mandates. Concerns over climate change, fossil fuel extraction, GHG emissions, and water and land-use practices could lead governments to enact additional or more stringent laws and regulations applicable to the Corporation and other companies in the energy industry in general. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs, and both the federal government and the Government of Alberta imposed more stringent environmental legislation that affects the thermal oil production industry. In addition, there is a risk that the federal and/or provincial governments could pass legislation that would tax air emissions or require, directly or indirectly, reductions in air emissions produced by energy industry participants, which the Corporation may be unable to mitigate. Should there be changes to existing laws or regulations, the Corporation’s competitive position within the thermal oil production industry may be adversely affected.

No assurance can be given that future environmental approvals, laws or regulations will not adversely impact the Corporation's ability to develop and operate its thermal oil production projects or increase or maintain production or control its costs of production. Changes to environmental regulations, including regulation relating to climate change, could impact the demand or pricing for the Corporation's products, or could require increased capital expenditures, operating expenses, abandonment and reclamation obligations and distribution costs, which may not be recoverable in the marketplace and which may result in current operations or growth projects becoming less profitable or uneconomic. Equipment which can meet future environmental standards may not be available on an economic or timely basis and instituting measures to ensure environmental compliance in the future may significantly increase operating costs or reduce output.

Any requirement to develop or implement new technology in response to future environmental standards could require a significant investment of capital and resources, and any delay in or failure to identify, develop and implement such technologies could prevent the Corporation from being able to operate profitably or being able to successfully compete with other companies.

No assurance can be given that environmental laws and regulations will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's results of operations, financial condition and prospects. The Corporation believes that it is reasonably likely that the trend towards stricter standards in environmental legislation will continue and anticipates that capital and operating costs may increase as a result of more stringent environmental laws.

Greenhouse Gas Regulations

The direct and indirect costs of the various GHG regulations, current and emerging in both Canada and the United States, including any limits on oil sands emissions and the Canadian federal government's implementation of the Paris Agreement through the Greenhouse Gas Pollution Act, the Clean Fuel Standard, the Alberta Technology Innovation and Emissions Reduction ("TIER") regulation and any other federal or provincial carbon emission pricing system, may adversely affect MEG's business, operations and financial results. New or additional carbon taxes or similar costs could significantly increase operating costs or reduce output. Equipment that meets future GHG emission standards may not be available on an economic basis and other compliance methods to reduce emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economical basis. Any failure to meet GHG emission reduction compliance obligations may have a material adverse effect on the Corporation's business and result in fines, penalties and the suspension of operations.

Draft regulations for the Clean Fuel Standard (the "Clean Fuel Regulations") were released in December 2020 and will be open for public comment until March 3, 2021. As proposed, the Clean Fuel Regulations only apply to liquid fuels, not gaseous and solid fuels, and will apply to producers or importers of gasoline, diesel, kerosene and light and heavy fuel oils (referred to as "primary suppliers"). Although the Clean Fuel Regulations, as proposed, do not apply to the Corporation's production of thermal oil, it is possible that, as a result of public comment on the proposed Regulations or otherwise, the Clean Fuel Standard in its final form could impose additional costs to the Corporation's operations, which may have a material adverse effect on the Corporation's results of operations. On December 11, 2020 the Government of Canada released a document entitled A Healthy Environment and a Healthy Economy which outlined 64 new and updated polices and programs to achieve net zero by 2050. This includes a proposal to increase the carbon price by $15 per year, starting in 2023, up to $170 per tonne of carbon pollution in 2030. The intent of the price adjustment is to incent cleaner fuel choices and discourage pollution-intensive investments.

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

Risks related to financing and the Corporation's indebtedness

Restrictions Contained in Credit Facility, Notes and Debt Service Obligations

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

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

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

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

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

Additional Indebtedness

Despite MEG's current level of indebtedness, it may still be able to incur substantially more debt, which could further exacerbate the risks associated with MEG's substantial indebtedness.

18. DISCLOSURE CONTROLS AND PROCEDURES

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. The CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the Corporation and have concluded that the Corporation's disclosure controls and procedures were effective at December 31, 2020 for the foregoing purposes.

19. INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation’s financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The CEO’s and CFO’s evaluation concluded that internal controls over financial reporting were effective as of December 31, 2020.

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 from mid-March until mid-September and then again in mid-December. 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.

20. ABBREVIATIONS

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

Financial and Business Environment

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

Measurement

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

21. ADVISORY

Forward-Looking Information

This document may contain forward-looking information 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, differentials, the level of apportionment on the Enbridge mainline system, foreign exchange rates and interest rates; the recoverability of the Corporation's reserves and contingent resources; the Corporation's ability to produce and market production of bitumen blend successfully to customers; 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; the Corporation's ability to reduce or increase production to desired levels, 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; 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 the Corporation conducts and will conduct its business; the impact of the Corporation'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.

These risks and uncertainties include, but are not limited to, risks and uncertainties related to: the oil and gas industry, for example, the securing of adequate 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, including public health crises, such as the COVID-19 pandemic, and any related actions taken by governments and businesses; legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws and production curtailment; the cost of compliance with current and future environmental laws, including climate change laws; risks relating 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; 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, including without negative impacts to its assets; 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; and changes in general economic, market and business conditions.

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 oil 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 (known as AWB) to customers 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.

22. ADDITIONAL INFORMATION

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

23. QUARTERLY SUMMARIES

	2020				2019			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**16**	(9)	(80)	(284)	26	24	(64)	(48)
Per share, diluted	**0.05**	(0.03)	(0.26)	(0.95)	0.09	0.08	(0.21)	(0.16)
Adjusted funds flow	**84**	27	89	78	157	192	227	151
Per share, diluted	**0.27**	0.09	0.29	0.26	0.51	0.63	0.76	0.50
Capital expenditures	**40**	36	20	54	72	40	33	53
Cash and cash equivalents	**114**	49	120	62	206	154	399	154
Working capital	**55**	131	173	371	123	204	416	175
Long-term debt	**2,912**	3,030	3,096	3,212	3,123	3,257	3,582	3,660
Shareholders' equity	**3,506**	3,495	3,507	3,593	3,853	3,828	3,795	3,851
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**42.66**	40.93	27.85	46.17	56.96	56.45	59.82	54.90
Differential – WTI:WCS – Edmonton (US$/bbl)	**(9.30)**	(9.09)	(11.47)	(20.53)	(15.83)	(12.24)	(10.67)	(12.29)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(10.56)**	(10.48)	(13.44)	(22.78)	(18.44)	(14.52)	(12.32)	(14.50)
AWB – Edmonton (US$/bbl)	**32.10**	30.45	14.41	23.39	38.52	41.93	47.50	40.40
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(2.83)**	(3.20)	(7.29)	(5.74)	(5.25)	(2.50)	1.64	(0.89)
AWB – U.S. Gulf Coast (US$/bbl)	**39.83**	37.73	20.56	40.43	51.71	53.95	61.46	54.01
C$ equivalent of 1US$ – average	**1.3031**	1.3316	1.3860	1.3445	1.3201	1.3207	1.3376	1.3293
Natural gas – AECO ($/mcf)	**2.88**	2.48	2.21	2.26	2.70	0.95	1.12	2.86
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**136,623**	93,479	100,980	142,380	134,932	132,455	137,120	132,377
Diluent usage – bbls/d	**(40,892)**	(25,910)	(30,583)	(45,166)	(40,585)	(37,463)	(42,000)	(42,555)
Bitumen sales – bbls/d	**95,731**	67,569	70,397	97,214	94,347	94,992	95,120	89,822
Bitumen production – bbls/d	**91,030**	71,516	75,687	91,557	94,566	93,278	97,288	87,113
Steam-oil ratio (SOR)	**2.31**	2.36	2.32	2.31	2.27	2.26	2.16	2.20
Blend sales	**45.75**	45.44	20.96	36.46	56.55	60.26	69.19	59.02
Cost of diluent	**(7.11)**	(5.76)	(10.78)	(17.01)	(9.69)	(6.89)	(6.96)	(8.81)
Bitumen realization	**38.64**	39.68	10.18	19.45	46.86	53.37	62.23	50.21
Transportation and storage – net	**(14.11)**	(18.55)	(11.77)	(8.63)	(10.75)	(10.57)	(10.80)	(11.27)
Third-party curtailment credits	**0.03**	—	—	0.18	(0.21)	(0.37)	(0.89)	—
Royalties	**(0.23)**	(0.21)	(0.05)	(0.63)	(1.18)	(1.54)	(2.06)	(0.37)
Operating costs – non-energy	**(4.70)**	(3.96)	(4.09)	(4.57)	(4.49)	(4.22)	(4.53)	(5.22)
Operating costs – energy	**(3.73)**	(3.17)	(3.00)	(3.15)	(2.95)	(1.51)	(1.78)	(3.36)
Power revenue	**1.45**	1.08	0.95	2.21	1.57	1.43	1.65	2.41
Realized gain (loss) on commodity risk management	**1.31**	1.71	33.62	11.97	(0.52)	(4.15)	(5.94)	(2.60)
Cash operating netback	**18.66**	16.58	25.84	16.83	28.33	32.44	37.88	29.80
Power sales price (C$/MWh)	**46.34**	39.03	28.34	69.39	49.61	50.30	55.33	70.83
Power sales (MW/h)	**125**	78	98	129	124	112	118	128
Average cost of diluent ($/bbl of diluent)	**62.37**	60.48	45.76	73.09	79.07	77.71	84.95	77.61
Average cost of diluent as a % of WTI	**112 %**	111 %	119 %	118 %	105 %	104 %	106 %	106 %
Depletion and depreciation rate per bbl of production	**12.64**	13.33	13.55	14.83	13.18	13.43	41.22	14.68
General and administrative expense per bbl of production	**1.65**	1.50	1.29	1.96	2.25	1.66	1.81	2.27
COMMON SHARES								
Shares outstanding, end of period (000)	**302,681**	302,657	302,645	299,547	299,508	299,288	299,207	296,857
Common share price ($) - close (end of period)	**4.45**	2.77	3.77	1.67	7.39	5.80	5.02	5.10

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$59.82/bbl, and the differential between WTI and the Corporation's AWB at Edmonton, which has ranged from a quarterly average of US$10.48/bbl to US$22.78/bbl driven by supply/demand fundamentals;
- beginning in early March 2020, followed by a slow recovery through the second half of 2020 and continued uncertainty, global crude oil prices experienced multi-decade lows coupled with extreme levels of volatility driven primarily by an unprecedented reduction in global demand due to 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 and non-energy costs due to reduction in staffing levels, and various non-recurring cost reductions in 2020;
- 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.

24. ANNUAL SUMMARIES

	2020	2019	2018[1]	2017[1]	2016[1]	2015[1]	2014[1]
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	(357)	(62)	(119)	166	(429)	(1,170)	(106)
Per share, diluted	(1.18)	(0.21)	(0.40)	0.57	(1.90)	(5.21)	(0.47)
Adjusted funds flow	278	726	180	374	(62)	49	791
Per share, diluted	0.91	2.41	0.60	1.29	(0.27)	0.22	3.52
Capital expenditures	149	198	622	502	140	314	1,314
Cash and cash equivalents	114	206	318	464	156	408	656
Working capital	55	123	290	313	96	363	526
Long-term debt	2,912	3,123	3,740	4,668	5,053	5,190	4,350
Shareholders' equity	3,506	3,853	3,886	3,964	3,287	3,678	4,768
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/bbl)	39.40	57.03	64.77	50.95	43.33	48.80	93.00
Differential – WTI:WCS – Edmonton (US$/bbl)	(12.60)	(12.76)	(26.31)	(11.98)	(13.84)	(13.52)	(19.40)
Differential – WTI:AWB – Edmonton (US$/bbl)	(14.32)	(14.95)	(29.99)	(14.09)	(16.40)	(16.69)	(23.58)
AWB – Edmonton (US$/bbl)	25.08	42.08	34.78	36.86	26.93	32.11	69.42
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	(4.77)	(1.77)	(6.68)	(7.61)	(11.53)	(8.53)	(10.08)
AWB - U.S. Gulf Coast (US$/bbl)	34.63	55.26	58.09	43.34	31.80	40.27	82.92
C$ equivalent of 1US$ – average	1.3413	1.3269	1.2962	1.2980	1.3256	1.2788	1.1047
Natural gas – AECO ($/mcf)	2.43	1.92	1.62	2.29	2.25	2.71	4.50
OPERATIONAL **($/bbl unless specified)**							
Blend sales, net of purchased product – bbls/d	118,347	134,223	125,368	115,766	116,586	117,132	97,334
Diluent usage – bbls/d	(35,626)	(40,637)	(38,317)	(35,766)	(36,159)	(36,167)	(30,092)
Bitumen sales – bbls/d	82,721	93,586	87,051	80,000	80,427	80,965	67,242
Bitumen production – bbls/d	82,441	93,082	87,731	80,774	81,245	80,025	71,186
Steam-oil ratio (SOR)	2.32	2.22	2.19	2.31	2.29	2.47	2.48
Blend sales	37.65	61.29	53.47	51.39	38.19	42.14	76.11
Cost of diluent	(10.42)	(8.08)	(16.78)	(9.36)	(10.28)	(11.43)	(13.35)
Bitumen realization	27.23	53.21	36.69	42.03	27.91	30.71	62.76
Transportation and storage – net	(12.92)	(10.84)	(8.42)	(6.89)	(6.46)	(4.82)	(1.38)
Third-party curtailment credits	0.06	(0.37)	—	—	—	—	—
Royalties	(0.31)	(1.30)	(1.20)	(0.77)	(0.29)	(0.70)	(4.36)
Operating costs – non-energy	(4.38)	(4.61)	(4.62)	(4.62)	(5.62)	(6.54)	(8.02)
Operating costs – energy	(3.29)	(2.38)	(1.98)	(2.98)	(3.01)	(3.84)	(6.30)
Power revenue	1.49	1.75	1.51	0.76	0.64	0.99	2.26
Realized gain (loss) on commodity risk management	11.34	(3.31)	(4.37)	(0.39)	0.08	—	—
Cash operating netback	19.22	32.15	17.61	27.14	13.25	15.80	44.96
Power sales price (C$/MWh)	47.81	56.70	47.87	21.49	18.74	27.48	48.83
Power sales (MW/h)	108	121	114	118	115	121	129
Average cost of diluent ($/bbl of diluent)	61.86	79.89	91.60	72.32	61.06	67.72	105.94
Average cost of diluent as a % of WTI	117 %	106 %	109 %	109 %	106 %	109 %	103 %
Depletion and depreciation rate per bbl of production	13.60	20.90	14.12	16.13	16.81	16.00	14.57
General and administrative expense per bbl of production	1.62	1.99	2.58	2.94	3.24	4.06	4.29
COMMON SHARES							
Shares outstanding, end of period (000)	302,681	299,508	296,841	294,104	226,467	224,997	223,847
Common share price ($) - close (end of period)	4.45	7.39	7.71	5.14	9.23	8.02	19.55

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

REPORT OF MANAGEMENT

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

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

The Corporation maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Corporation’s assets are properly accounted for and adequately safeguarded. Management’s evaluation concluded that the Corporation’s internal controls over financial reporting were effective as of December 31, 2020.

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

PricewaterhouseCoopers LLP, an independent firm of auditors, has been engaged, as approved by a vote of the shareholders at the Corporation’s most recent Annual General Meeting, to audit and provide their independent audit opinion on the Corporation’s consolidated financial statements as at and for the year ended December 31, 2020. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

/s/ Derek Evans

Derek Evans
President and Chief Executive Officer

/s/ Eric L. Toews

Eric L. Toews, CPA, CA
Chief Financial Officer

March 3, 2021

Independent auditor's report

To the Shareholders of MEG Energy Corp.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of MEG Energy Corp. and its subsidiary (together, the Corporation) as at December 31, 2020 and 2019, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited

The Corporation's consolidated financial statements comprise:

- the consolidated balance sheets as at December 31, 2020 and 2019;
- the consolidated statements of earnings (loss) and comprehensive income (loss) for the years then ended;
- the consolidated statements of changes in shareholders' equity for the years then ended;
- the consolidated statements of cash flow for the years then ended; and
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

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

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

Independence

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

PricewaterhouseCoopers LLP
111-5th Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2020. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Key audit matter	How our audit addressed the key audit matter
The impact of bitumen reserves on crude oil assets *See note 3 – Significant accounting policies, note 4 – Significant accounting estimates, assumptions and judgments and note 7 – Property, plant and equipment to the consolidated financial statements.* The Corporation's crude oil asset balance was \$5.665 billion as of December 31, 2020 and the related depletion and depreciation (D&D) expense was \$384 million for the year then ended. Crude oil assets consist mainly of field production assets and major facilities and equipment. Field production assets are depleted using the unit-of-production method based on estimated proved reserves and major facilities and equipment are depreciated on a unit-of-production basis over the estimated total productive capacity of the asset. Property, plant and equipment (PP&E) assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated. For the purpose of estimating the asset's recoverable amount, PP&E assets are grouped into cash generating units (CGUs). The recoverable amount of a CGU is determined as the greater of its value in use and its fair value less costs of disposal. In determining fair value less costs of disposal, recent market transactions are taken into account if available. In the absence of such a transaction, an appropriate valuation model is used, such as a discounted cash flow model	Our approach to addressing the matter involved the following procedures, among others: • The work of management's expert was used in performing the procedures to evaluate the reasonableness of the proved and probable bitumen reserves used to determine D&D expense and the recoverable amount of the Corporation's CGU. As a basis for using this work, the expert's competence, capability and objectivity were evaluated, their work performed was understood and the appropriateness of the expert's work as audit evidence was evaluated by considering the relevance and reasonableness of the assumptions and methods. • Tested how management determined the recoverable amount of the Corporation's CGU and D&D expense, which included the following: – Evaluated the appropriateness of the methods and models used by management in making these estimates. – Evaluated the reasonableness of significant assumptions used in developing the underlying estimate, including: o future commodity prices by comparing those prices with other reputable third party industry forecasts; o expected production volumes, quantity of proved and probable bitumen reserves, future development and

Key audit matter	How our audit addressed the key audit matter
involving significant assumptions such as future commodity prices, expected production volumes, quantity of proved and probable reserves and discount rates as well as future development and operating costs. The Corporation's proved and probable bitumen reserves are also reviewed by the Corporation's independent reserve engineers (management's expert). An impairment loss is recognized in earnings or loss if the carrying amount of its CGU exceeds its estimated recoverable amount. We determined that this is a key audit matter due to (i) the significant judgment made by management, including the use of management's expert, when developing the expected future cash flows to determine the recoverable amount of the CGU and the proved and probable bitumen reserves; (ii) a high degree of auditor judgment, subjectivity and effort in performing audit procedures relating to the significant assumptions; and (iii) the audit effort that involved the use of professionals with specialized skill and knowledge in the field of valuation.	operating costs by considering the past performance of the Corporation's CGU, and whether these assumptions were consistent with evidence obtained in other areas of the audit; and o the discount rate, through the assistance of professionals with specialized skill and knowledge in the field of valuation. – Recalculated the unit-of-production rates used to calculate depletion expense related to field production assets. – Evaluated the reasonableness of the total productive capacity assumptions used for facilities and recalculated depreciation expense for major facilities and equipment.

Other information

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

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

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

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

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

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

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

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

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

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

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

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management’s use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation’s ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Corporation to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

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

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

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor’s report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

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

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
March 3, 2021

Consolidated Balance Sheet
(Expressed in millions of Canadian dollars)

As at December 31	Note		2020		2019
Assets					
Current assets					
Cash and cash equivalents	22	**$**	**114**	$	206
Trade receivables and other	5		**281**		382
Inventories	6		**96**		93
Risk management	24		**6**		—
			497		681
Non-current assets					
Property, plant and equipment	7		**5,993**		6,206
Exploration and evaluation assets	8		**125**		490
Other assets	9		**206**		227
Risk management	24		**21**		—
Deferred income tax asset	12		**382**		262
Total assets		**$**	**7,224**	$	7,866
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities		**$**	**279**	$	379
Interest payable			**78**		74
Current portion of provisions and other liabilities	11		**56**		28
Risk management	24		**29**		77
			442		558
Non-current liabilities					
Long-term debt	10		**2,912**		3,123
Provisions and other liabilities	11		**364**		332
Total liabilities			**3,718**		4,013
Shareholders' equity					
Share capital	13		**5,460**		5,443
Contributed surplus			**177**		182
Deficit			**(2,158)**		(1,801)
Accumulated other comprehensive income			**27**		29
Total shareholders' equity			**3,506**		3,853
Total liabilities and shareholders' equity		**$**	**7,224**	$	7,866

Commitments and contingencies (Note 27)

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

These Consolidated Financial Statements were approved by the Corporation's Board of Directors on March 3, 2021.

/s/ Derek Evans

Derek Evans, Director

/s/ Robert B. Hodgins

Robert B. Hodgins, Director

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

Year ended December 31	Note		2020		2019
Revenues					
Petroleum revenue, net of royalties	15	$	**2,235**	$	3,858
Other revenue	15		**57**		73
Total revenues			**2,292**		3,931
Expenses					
Diluent and transportation	16		**1,210**		1,568
Operating expenses			**232**		238
Purchased product			**613**		900
Production curtailment credits purchased (sold)			**(2)**		13
Depletion and depreciation	7, 9		**410**		710
Exploration expense	8		**366**		58
General and administrative			**49**		68
Stock-based compensation	14		**(14)**		31
Net finance expense	18		**284**		340
Other expenses	19		**68**		23
Other income	20		**(6)**		(34)
Commodity risk management (gain) loss, net	24		**(392)**		282
Foreign exchange (gain) loss, net	17		**(49)**		(175)
Loss before income taxes			**(477)**		(91)
Income tax expense (recovery)			**(120)**		(29)
Net loss			**(357)**		(62)
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment			**(2)**		(10)
Comprehensive loss		$	**(359)**	$	(72)
Net loss per common share					
Basic	23	$	**(1.18)**	$	(0.21)
Diluted	23	$	**(1.18)**	$	(0.21)

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

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

		Share Capital		Contributed Surplus		Deficit		Accumulated Other Comprehensive Income		Total Shareholders' Equity
Balance as at December 31, 2019	**$**	**5,443**	**$**	**182**	**$**	**(1,801)**	**$**	**29**	**$**	**3,853**
Stock-based compensation		**—**		**12**		**—**		**—**		**12**
RSUs vested and released		**17**		**(17)**		**—**		**—**		**—**
Comprehensive income (loss)		**—**		**—**		**(357)**		**(2)**		**(359)**
Balance as at December 31, 2020	**$**	**5,460**	**$**	**177**	**$**	**(2,158)**	**$**	**27**	**$**	**3,506**
Balance as at December 31, 2018	$	5,427	$	170	$	(1,751)	$	39	$	3,885
IFRS 16 opening deficit adjustment		—		—		12		—		12
Stock-based compensation		—		26		—		—		26
Stock options exercised		2		—		—		—		2
RSUs vested and released		14		(14)		—		—		—
Comprehensive income (loss)		—		—		(62)		(10)		(72)
Balance as at December 31, 2019	$	5,443	$	182	$	(1,801)	$	29	$	3,853

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

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

Year ended December 31	Note	2020	2019
Cash provided by (used in):			
Operating activities			
Net loss		**$ (357)**	$ (62)
Adjustments for:			
Deferred income tax expense (recovery)	12	**(120)**	(29)
Depletion and depreciation	7, 9	**410**	710
Exploration expense	8	**366**	58
Stock-based compensation	14	**(15)**	24
Unrealized net (gain) loss on foreign exchange	17	**(47)**	(172)
Unrealized net (gain) loss on commodity risk management	24	**(49)**	169
Amortization of debt discount and debt issue costs	10	**8**	15
Gain on asset dispositions	20	**(6)**	(14)
Debt extinguishment expense	18	**12**	46
Other		**9**	6
Decommissioning expenditures	11	**(3)**	(2)
Onerous contract expense	11	**25**	—
Net change in other liabilities		**6**	(8)
Funds flow from operating activities		**239**	741
Net change in non-cash working capital items	22	**63**	(110)
Net cash provided by (used in) operating activities		**302**	631
Investing activities			
Capital expenditures	7	**(149)**	(198)
Net proceeds on dispositions	9	**6**	18
Other		**—**	(1)
Net change in non-cash working capital items	22	**(46)**	(30)
Net cash provided by (used in) investing activities		**(189)**	(211)
Financing activities			
Issue of 7.125% senior unsecured notes	10	**1,581**	—
Repayment and redemption of long-term debt	10	**(1,723)**	(297)
Repurchase of senior secured second lien notes	10	**—**	(204)
Debt redemption premium and refinancing costs	10	**(49)**	(5)
Issue of shares, net of issue costs		**—**	1
Receipts on leased assets	22	**1**	1
Payments on leased liabilities	22	**(26)**	(19)
Net cash provided by (used in) financing activities		**(216)**	(523)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**11**	(9)
Change in cash and cash equivalents		**(92)**	(112)
Cash and cash equivalents, beginning of period		**206**	318
Cash and cash equivalents, end of period		**$ 114**	**$ 206**

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

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange under the symbol "MEG". The Corporation owns a 100% interest in over 450 square miles of mineral leases in the southern Athabasca oil region of Alberta, Canada and is primarily engaged in sustainable *in situ* thermal oil production at its Christina Lake Project.

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

2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board ("IASB"). The consolidated financial statements have been prepared on the historical cost basis, except as detailed in the significant accounting policies disclosed in Note 3. These audited consolidated financial statements were approved by the Corporation's Board of Directors on March 3, 2021.

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 contributed to significant declines and volatility in capital and financial markets, and adversely impacted global commodity markets, 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 global efforts to contain the spread and severity of the virus.

The full extent of the impact of COVID-19 on the Corporation’s operations and future financial performance is currently unknown. The continued impact on capital and financial markets on a macro-scale presents uncertainty and risk with respect to the Corporation's performance, and estimates and assumptions used in the preparation of its financial results.

3. SIGNIFICANT ACCOUNTING POLICIES

a. Principles of consolidation

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

b. Foreign currency translation

i. Functional and presentation currency

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

ii. Transactions and balances

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

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

c. Financial instruments

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

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

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

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

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

i. Financial assets

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

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

ii. Financial liabilities

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

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

d. Cash and cash equivalents

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

e. Trade receivables and other

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

f. Inventories

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

g. Exploration and evaluation assets

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

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

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

h. Property, plant and equipment

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

i. Crude oil

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

Field production assets are depleted using the unit-of-production method based on estimated proved reserves. Costs subject to depletion include estimated future development costs required to develop and produce the proved reserves. These estimates are reviewed by independent reserve engineers at least annually. Independent reserve engineers also review proved plus probable bitumen reserves used in calculating recoverable amounts used for impairment testing.

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

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

ii. Transportation and storage

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

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

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

iv. Corporate assets

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

v. Asset dispositions

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

i. Intangible assets

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

j. Leases

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

As Lessee

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

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

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

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

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

As Lessor

As a lessor, the Corporation assesses at inception whether a lease is a finance or operating lease. Leases where the Corporation transfers substantially all of the risk and rewards incidental to ownership of the underlying asset are classified as financing leases. Under a finance lease, the Corporation recognizes a receivable at an amount equal to the net investment in the lease which is the present value of the aggregate of lease payments receivable by the lessor. As an intermediate lessor, the Corporation accounts for its interest in head leases and subleases separately. If substantially all the risks and rewards of ownership of an asset are not transferred the lease is classified as an operating lease. The Corporation recognizes lease payments received under operating leases as income on a straight-line basis over the lease term as other income.

k. Impairments

i. Financial assets

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

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

ii. Non-financial assets

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

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

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

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

l. Provisions

i. General

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

ii. Decommissioning provision

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

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

iii. Onerous contracts

A provision for an onerous contract is recognized when the unavoidable cost of meeting the obligations under the contract exceed the economic benefits expected to be derived from the contract. The net amount of actual costs incurred are charged against the onerous contract provision.

iv. Emissions obligations

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

m. Deferred income taxes

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

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

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

n. Share capital

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

o. Share based payments

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

i. Equity-settled

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

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

ii. Cash-settled

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

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

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

p. Revenue recognition

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

i. Petroleum revenue and royalties

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

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

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

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

ii. Other revenue

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

q. Net earnings (loss) per share

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

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

r. Government grants

Government grants are recognized when there is reasonable assurance that the Corporation will receive the grant and comply with the conditions attached to the grant. When a grant relates to income, it is recognized in earnings or loss over the period in which the grant is intended to compensate. When a grant relates to an asset, it is recognized as a reduction of the carrying amount of the related asset.

4. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGMENTS

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

a. Property, plant and equipment

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

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

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

b. Exploration and evaluation assets

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

c. Bitumen reserves

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

d. Decommissioning provision

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

e. Impairments

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

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

f. Stock-based compensation

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

g. Deferred income taxes

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

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

A deferred tax asset is recognized to the extent that it is probable that future taxable earnings will be available against which the temporary difference can be utilized. The extent to which a deferred tax asset may be utilized involves a significant amount of estimation and judgment including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings and the availability of cash flow to offset the tax assets when the reversal occurs.

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

h. Derivative financial instruments

The estimated fair values of financial assets and liabilities are subject to measurement uncertainty due to their exposure to credit, liquidity and market risks. Furthermore, the Corporation may use derivative instruments to manage commodity price, foreign currency and interest rate exposures. The fair values of these derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows, and discount rates. Management's assumptions rely on external observable market data including quoted forward commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and as such are subject to measurement uncertainty.

i. Leases

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

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

A lease modification will be accounted for as a separate lease if the modification increases the scope of the lease and if the consideration for the lease increases by an amount commensurate with the stand-alone price for the increase in scope. For a modification that is not a separate lease or where the increase in consideration is not commensurate, at the effective date of the lease modification, the Company will remeasure the lease liability using the Company's incremental borrowing rate, when the rate implicit to the lease is not readily available, with a corresponding adjustment to the ROU asset. A modification that decreases the scope of the lease will be accounted for by decreasing the carrying amount of the ROU asset, and recognizing a gain or loss in net earnings that reflects the proportionate decrease in scope.

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

5. TRADE RECEIVABLES AND OTHER

As at December 31	2020	2019
Trade receivables	**$ 261**	$ 359
Deposits and advances	**15**	18
Current portion of deferred financing costs	**3**	3
Current portion of sublease receivable	**2**	2
	$ 281	$ 382

6. INVENTORIES

As at December 31	2020	2019
Bitumen blend	**$ 81**	$ 73
Diluent	**7**	13
Material and supplies	**8**	7
	$ 96	$ 93

During the year ended December 31, 2020, a total of $0.8 billion (2019 - $1.2 billion) in inventory product costs were charged to earnings through diluent and transportation expense.

7. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Right-of-use assets	Corporate assets	Total
Cost					
Balance as at December 31, 2018	$ 8,880	$ 159	$ 196	$ 77	$ 9,312
IFRS 16 opening balance sheet adjustment	—	—	58	—	58
Additions	199	—	13	1	213
Dispositions	(3)	—	(4)	—	(7)
Change in decommissioning liabilities	1	—	—	—	1
Balance as at December 31, 2019	$ 9,077	$ 159	$ 263	$ 78	$ 9,577
Additions	151	—	26	—	177
Dispositions	(3)	(71)	—	—	(74)
Lease modification	—	—	7	—	7
Change in decommissioning liabilities	20	—	—	—	20
Balance as at December 31, 2020	**$ 9,245**	**$ 88**	**$ 296**	**$ 78**	**$ 9,707**

Accumulated depletion and depreciation					
Balance as at December 31, 2018	2,610	12	5	39	2,666
Depletion and depreciation	592	90	20	6	708
Dispositions	(3)	—	—	—	(3)
Balance as at December 31, 2019	$ 3,199	$ 102	$ 25	$ 45	$ 3,371
Depletion and depreciation	384	—	23	4	411
Dispositions	(3)	(70)	—	—	(73)
Lease modification	—	—	5	—	5
Balance as at December 31, 2020	**$ 3,580**	**$ 32**	**$ 53**	**$ 49**	**$ 3,714**
Carrying amounts					
Balance as at December 31, 2019	$ 5,878	$ 57	$ 238	$ 33	$ 6,206
Balance as at December 31, 2020	**$ 5,665**	**$ 56**	**$ 243**	**$ 29**	**$ 5,993**

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

As at December 31, 2020, property, plant and equipment was assessed for impairment and no impairment was recognized. The appropriate discount rate requires a significant amount of judgment, and a sensitivity analysis was performed to ensure that a 1-2% change in the discount rate did not affect the conclusion reached that no impairment was required. Included in the cost of property, plant and equipment is $244 million of assets under construction as at December 31, 2020 (December 31, 2019 – $229 million).

8. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2018	$	550
Additions		1
Exploration expense		(58)
Dispositions		(3)
Balance as at December 31, 2019	$	490
Additions		1
Exploration expense		(366)
Dispositions		—
Balance as at December 31, 2020	**$**	**125**

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. The Corporation is focused on the development of its core assets as it continues to manage the business through an unpredictable global economic downturn arising from COVID-19. During the first quarter of 2020, the Corporation discontinued exploration and evaluation activities in certain non-core growth properties. Land lease and evaluation costs associated with these assets of $366 million were charged to exploration expense during the first quarter of 2020. The remaining assets were allocated to the related CGU for impairment testing and no impairment was required.

9. OTHER ASSETS

As at December 31		2020		2019
Non-current pipeline linefill[(a)]	**$**	**176**	$	190
Finance sublease receivables		**17**		18
Intangible assets[(b)]		**7**		9
Deferred financing costs		**3**		7
Prepaid transportation costs[(c)]		**8**		9
		211		233
Less current portion, included in trade receivables and other		**(5)**		(6)
	$	**206**	$	227

a. Non-current pipeline linefill on third-party owned pipelines is classified as a non-current asset as these transportation contracts expire between the years 2025 and 2048. As at December 31, 2020, no impairment has been recognized on these assets.

b. As at December 31, 2020, intangible assets consist of $7 million invested in software that is not an integral component of the related computer hardware (December 31, 2019 – $9 million). Depreciation of $2 million was recognized for the year ended December 31, 2020 (year ended December 31, 2019 – $2 million). At the beginning of 2020, the Corporation sold patents that were recorded at a nominal amount, and recognized a gain on asset disposition of $6 million. During the year ended December 31, 2019, the Corporation sold internally generated emission performance credits that were recorded at a nominal amount, and recognized a gain on asset dispositions of $12 million.

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

10. LONG-TERM DEBT

As at December 31		2020		2019
Second Lien:				
6.5% senior secured second lien notes[d] (December 31, 2020 - US$496 million; December 31, 2019 - US$596 million; due 2025)	**$**	**633**	$	773
Unsecured:				
7.0% senior unsecured notes[b] (December 31, 2020 - US$600 million; December 31, 2019 - US$1 billion; due 2024)		**765**		1,297
7.125% senior unsecured notes[a] (December 31, 2020 - US$1.2 billion; December 31, 2019 - US$nil; due 2027)		**1,531**		—
6.375% senior unsecured notes[c] (December 31, 2020 - US$nil; December 31, 2019 - US$800 million; due 2023)		**—**		1,037
		2,929		3,107
Less:				
Debt redemption premium		**9**		29
Unamortized deferred debt discount and debt issue costs		**(26)**		(13)
	$	**2,912**	$	3,123

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2755 (December 31, 2019 – US$1 = C$1.2965).

a. Effective 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 with a maturity of February 1, 2027. Interest is paid semi-annually in February and August. No principal payments are required until February 1, 2027. The Corporation has deferred the associated debt issue costs of $20 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

   On February 18, 2020, net proceeds from this January 31, 2020 private 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%[c];
   - Partially redeem $530 million (US$400 million) of the US$1.0 billion 7.00% senior unsecured notes due March 2024 at a redemption price of 102.333%[b]; and
   - Pay fees and expenses related to the offering.

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

   On February 18, 2020, net proceeds from the January 31, 2020 private offering, together with cash-on-hand, were used to partially redeem $530 million (US$400 million) of the US$1.0 billion 7.00% senior unsecured notes due March 2024 at a redemption price of 102.333%. As at December 31, 2020 $765 million (US$600 million) aggregate principal amount of 7.00% senior unsecured notes remain outstanding.

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

   On February 18, 2020, net proceeds from the January 31, 2020 private 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%. As at December 31, 2020 no balance remains outstanding.

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

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

   On February 18, 2020, the Corporation redeemed $132 million (US$100 million) in aggregate principal amount of its 6.5% senior secured second lien notes due January 2025 at a redemption price of 104.875%. Cash-on-hand was used to fund this senior secured second lien notes partial redemption. As at December 31, 2020 $633 million (US$496 million) aggregate principal amount of 6.5% senior secured second lien notes remain outstanding.

Each of the February 18, 2020 redemptions described above include prepayment options whereby the Corporation is required to make an estimate at each reporting date of the likelihood of the prepayment option being exercised. Given the January 31, 2020 closing date, prepayment options were recognized at December 31, 2019 under *IAS 10, Events After the Reporting Period*, as an adjusting subsequent event. For the year ended December 31, 2019, the Corporation recognized a cumulative debt redemption premium of $29 million and associated unamortized deferred debt issue costs of $10 million recognized in net finance expense (Note 18).

Throughout the second half of 2019, the Corporation repurchased and extinguished $204 million (US$154 million) aggregate principal amount of its senior secured second lien notes. Included in debt extinguishment expense during the year ended December 31, 2019 is a $4 million premium paid on the repurchase of the senior secured second lien notes and related unamortized deferred debt issue costs of $3 million recognized in net finance expense (Note 18).

Subsequent to December 31, 2020, on February 2, 2021, the Corporation successfully closed on a private offering of US$600 million in aggregate principal amount of 5.875% senior unsecured notes due February 2029. The net proceeds of the offering, together with cash-on-hand, were used to fully redeem US$600 million in aggregate principal amount of its 7.00% senior unsecured notes due March 2024 at a redemption price of 101.167% and to pay fees and expenses related to the offer. The redemption includes a prepayment option whereby the Corporation is required to make an estimate at the reporting date of the likelihood of the prepayment option being exercised. Given the February 2, 2021 closing date, a prepayment option was recognized at December 31, 2020 under *IAS 10, Events After the Reporting Period*, as an adjusting subsequent event. For the year ended December 31, 2020, the Corporation recognized a debt redemption premium of $9 million and associated unamortized deferred debt issue costs of $3 million recognized in net finance expense (Note 18).

The Corporation's total credit available under two facilities is $1.3 billion, comprised of $800 million under a revolving credit facility and $500 million under a letter of credit facility, guaranteed by Export Development Canada ("EDC"). Letters of credit under the EDC facility do not consume capacity of the revolving credit facility. The revolving credit facility and the EDC facility both have a maturity date of July 30, 2024. The revolving credit facility, EDC facility and senior secured second lien notes are secured by substantially all the assets of the Corporation.

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

As at December 31, 2020, the Corporation had $785 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $100 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 year ended December 31, 2020.

11. PROVISIONS AND OTHER LIABILITIES

As at December 31		2020		2019
Lease liabilities[a]	**$**	**286**	$	281
Decommissioning provision[b]		**96**		71
Onerous contract provision[c]		**25**		—
Other liabilities		**13**		8
Provisions and other liabilities		**420**		360
Less current portion		**(56)**		(28)
Non-current portion	**$**	**364**	$	332

a. Lease liabilities:

As at December 31		2020		2019
Balance, beginning of period	**$**	**281**	$	131
IFRS 16 opening balance sheet adjustment		**—**		160
Additions		**19**		13
Modifications		**7**		(4)
Payments		**(47)**		(45)
Interest expense		**26**		26
Balance, end of period		**286**		281
Less current portion		**(28)**		(22)
Non-current portion	**$**	**258**	$	259

The Corporation's minimum lease payments are as follows:

As at December 31		2020
Within one year	**$**	**52**
Later than one year but not later than five years		**148**
Later than five years		**499**
Minimum lease payments		**699**
Amounts representing finance charges		**(413)**
Net minimum lease payments	**$**	**286**

The Corporation has short-term leases with lease terms of twelve months or less as well as low-value leases. As these lease costs are incurred they are recognized as either general and administrative expense or operating expense depending on their nature. As at December 31, 2020, the present value of these arrangements is $1 million (December 31, 2019 - $2 million), using the Corporation's estimated incremental borrowing rate.

b. Decommissioning provision:

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

As at December 31	2020	2019
Balance, beginning of period	**$ 71**	$ 65
Changes in estimated life and estimated future cash flows	**4**	(2)
Changes in discount rates	**16**	2
Liabilities incurred and disposed, net	**—**	1
Liabilities settled	**(3)**	(2)
Accretion	**8**	7
Balance, end of period	**96**	71
Less current portion	**(3)**	(6)
Non-current portion	**$ 93**	$ 65

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The total undiscounted amount of the estimated future cash flows to settle the decommissioning obligations is $802 million (December 31, 2019 – $827 million). As at December 31, 2020, the Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 11.7% (December 31, 2019 – 13.7%) and an inflation rate of 2.1% (December 31, 2019 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2019 - periods up to the year 2066).

c. Onerous contract provision:

As at December 31, 2020, the Corporation recognized a provision of $25 million related to an onerous marketing contract with a remaining term of one year. The provision represents the present value of the minimum future payments that the Corporation is obligated to make under the non-cancelable onerous contract. There is no impact from discounting as the onerous contract will be settled by December 31, 2021.

12. INCOME TAX

Year ended December 31		2020		2019
	$	**(477)**	$	(91)
Statutory income tax rate		**24.0 %**		26.5 %
Expected income tax expense (recovery)		**(114)**		(24)
Add (deduct) the tax effect of:				
Stock-based compensation		**3**		6
Non-taxable loss (gain) on foreign exchange		**(4)**		(24)
Taxable capital loss (gain) not recognized		**(4)**		(23)
Tax benefit of vested RSUs		**(1)**		(3)
Alberta tax rate reduction		**—**		33
Other		**—**		6
Income tax expense (recovery)	**$**	**(120)**	$	(29)
Current income tax expense (recovery)	**$**	**—**	$	—
Deferred income tax expense (recovery)		**(120)**		(29)
Income tax expense (recovery)	**$**	**(120)**	$	(29)

As at December 31, 2020, the Corporation has recognized a deferred tax asset of $382 million (December 31, 2019 - $262 million). The deferred tax asset is reviewed at each balance sheet date to assess whether it is probable that the related tax benefit will be realized. Future taxable income is expected to be sufficient to realize the deferred tax asset.

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

On June 28, 2020, the Government of Alberta further announced a proposal to accelerate the previous corporate tax rate reduction and reduce the corporate tax rate in 2020 from 10% to 8%, effective July 1, 2020, which was enacted in the fourth quarter of 2020. As the Corporation had previously revalued its deferred tax asset at the reduced Alberta tax rate of 8%, the rate reduction had no further impact on the Corporation's deferred tax position.

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

		2020		2019
Balance as at January 1	**$**	**262**	$	237
Credited (charged) to earnings		**120**		29
Credited (charged) to equity		**—**		(4)
Balance as at December 31	**$**	**382**	$	262

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

Deferred tax assets	Tax losses	Commodity risk management	Decommissioning provision	Right-of-use assets	Other	Total
Balance as at December 31, 2018	$ 1,371	$ —	$ 18	$ 35	$ 56	$ 1,480
Credited (charged) to earnings	(205)	18	(1)	13	(6)	(181)
Credited (charged) to equity	—	—	—	12	(5)	7
Balance as at December 31, 2019	**1,166**	**18**	**17**	**60**	**45**	**1,306**
Credited (charged) to earnings	**10**	**(17)**	**5**	**(1)**	**4**	**1**
Balance as at December 31, 2020	**$ 1,176**	**$ 1**	**$ 22**	**$ 59**	**$ 49**	**$ 1,307**

Deferred tax liabilities	Property, plant and equipment	Commodity risk management	Total
Balance as at December 31, 2018	$ (1,218)	$ (25)	$ (1,243)
Credited (charged) to earnings	185	25	210
Credited (charged) to equity	(11)	—	**(11)**
Balance as at December 31, 2019	**(1,044)**	**—**	**(1,044)**
Credited (charged) to earnings	**119**	**—**	**119**
Balance as at December 31, 2020	**$ (925)**	**$ —**	**$ (925)**

As at December 31, 2020, the Corporation had approximately $7.4 billion in available tax pools (December 31, 2019 - $7.3 billion). Included in the tax pools are $5.1 billion of non-capital loss carry forward balances expiring as follows:

	2026	2027	2028	2029	2030	Thereafter	Total
Non-capital loss carry forward balances	$ 200	$ 250	$ 350	$ 500	$ 250	$ 3,550	$ 5,100

In addition, as at December 31, 2020, the Corporation had an additional $111 million (December 31, 2019 - $101 million) of capital investment in incomplete projects which will serve to increase available tax pools upon completion of the projects. As at December 31, 2020, the Corporation had not recognized the tax benefit related to $326 million of realized and unrealized taxable capital foreign exchange losses (December 31, 2019 - $343 million).

13. SHARE CAPITAL

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

Changes in issued common shares are as follows:

	2020		2019	
	Number of shares (thousands)	Amount	Number of shares (thousands)	Amount
Balance, beginning of year	**299,508**	**$ 5,443**	296,841	$ 5,427
Issued upon exercise of stock options	**39**	**—**	266	2
Issued upon vesting and release of RSUs and PSUs	**3,134**	**17**	2,401	14
Balance, end of period	**302,681**	**$ 5,460**	299,508	$ 5,443

14. STOCK-BASED COMPENSATION

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

a. Stock-based compensation

Year ended December 31	2020	2019
Cash-settled expense[(i)]	**$ 1**	$ 7
Equity-settled expense	**11**	24
Equity price risk management (gain) loss[(ii)]	**(26)**	—
Stock-based compensation	**$ (14)**	$ 31

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

(ii) 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 note 24(c) for further details.

b. Cash-settled plans

i. Restricted share units and performance share units:

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

Cash-settled RSUs and PSUs outstanding:

Year ended December 31 (expressed in thousands)	2020	2019
Outstanding, beginning of year	**3,254**	4,263
Granted	**8,328**	2,285
Vested and released	**(2,438)**	(2,808)
Forfeited	**(1,013)**	(486)
Outstanding, end of year	**8,131**	3,254

ii. Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of DSUs to directors of the Corporation. A DSU represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares purchased through a broker. DSUs vest immediately when granted and are redeemed on the earlier of (a) December 15 of the first calendar year starting after the date the holder ceases to be a member of the Corporation, and (b) the fifth business day following each of the redemption dates elected by such holder. As at December 31, 2020, there were 998,300 DSUs outstanding (December 31, 2019 – 734,347 DSUs outstanding).

As at December 31, 2020, the Corporation recognized a liability of $23 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2019 – $25 million). The current portion of $10 million is included within accounts payable and accrued liabilities and $13 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards.

c. Equity-settled plans

i. Stock options outstanding:

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

Year ended December 31	2020		2019	
	Stock options (thousands)	**Weighted average exercise price**	**Stock options (thousands)**	**Weighted average exercise price**
Outstanding, beginning of year	**6,761**	**$ 18.08**	8,517	$ 21.27
Granted	**—**	**—**	683	4.57
Exercised	**(39)**	**6.44**	(266)	5.20
Forfeited	**(1,158)**	**20.18**	(1,198)	21.60
Expired	**(888)**	**30.99**	(975)	35.69
Outstanding, end of year	**4,676**	**$ 15.21**	6,761	$ 18.08

As at December 31, 2020							
	Outstanding			Vested			
Range of exercise prices	Options (thousands)	Weighted average exercise price	Weighted average remaining life (in years)	Options (thousands)	Weighted average exercise price	Weighted average remaining life (in years)
$4.53 - $10.00	2,481	$ 6.00	3.90	2,025	$ 6.09	3.60
$10.01 - $30.00	1,396	18.59	1.44	1,396	18.59	1.44
$30.01 - $38.68	799	37.90	0.45	799	37.90	0.45
	4,676	**$ 15.21**	**2.58**	**4,220**	**$ 16.25**	**2.29**

There were no stock options granted during the year ended December 31, 2020. The fair value of each option granted during the year ended December 31, 2019 was estimated on the date of the grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

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

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

ii. Restricted share units and performance share units:

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

Equity-settled RSUs and PSUs outstanding:

Year ended December 31 (expressed in thousands)	2020	2019
Outstanding, beginning of year	**6,393**	6,534
Granted	**4,675**	3,342
Vested and released	**(3,134)**	(2,401)
Forfeited	**(1,403)**	(1,082)
Outstanding, end of year	**6,531**	6,393

15. REVENUES

Year ended December 31	2020	2019
Sales from:		
Production	$ 1,594	$ 2,996
Purchased product[(i)]	650	907
Petroleum revenue	$ 2,244	$ 3,903
Royalties	(9)	(45)
Petroleum revenue, net of royalties	$ 2,235	$ 3,858
Power revenue	$ 45	$ 60
Transportation revenue	12	13
Other revenue	$ 57	$ 73
Total revenues	$ 2,292	$ 3,931

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

a. Disaggregation of revenue from contracts with customers

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

	Year ended December 31					
	2020			2019		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	$ 754	$ 50	$ 804	$ 1,820	$ 261	$ 2,081
United States	840	600	1,440	1,176	646	1,822
	$ 1,594	$ 650	$ 2,244	$ 2,996	$ 907	$ 3,903

Other revenue recognized during the years ended December 31, 2020 and 2019 is attributed to Canada.

b. Revenue-related assets

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

As at December 31	2020	2019
Petroleum revenue	$ 249	$ 342
Other revenue	4	9
Total revenue-related assets	$ 253	$ 351

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

16. DILUENT AND TRANSPORTATION

Year ended December 31		2020		2019
Diluent expense	**$**	**807**	$	1,185
Transportation and storage		**403**		383
Diluent and transportation	**$**	**1,210**	$	1,568

17. FOREIGN EXCHANGE (GAIN) LOSS, NET

Year ended December 31		2020		2019
Unrealized foreign exchange (gain) loss on:				
Long-term debt	**$**	**(36)**	$	(180)
US$ denominated cash and cash equivalents		**(11)**		8
Unrealized net (gain) loss on foreign exchange		**(47)**		(172)
Realized (gain) loss on foreign exchange		**(2)**		(3)
Foreign exchange (gain) loss, net	**$**	**(49)**	$	(175)

C$ equivalent of 1 US$		
Beginning of period	**1.2965**	1.3646
End of period	**1.2755**	1.2965

18. NET FINANCE EXPENSE

Year ended December 31		2020		2019
Interest expense on long-term debt	**$**	**241**	$	267
Interest expense on lease liabilities		**26**		26
Interest income		**(3)**		(5)
Net interest expense		**264**		288
Debt extinguishment expense[(a)(b)]		**12**		46
Accretion on provisions		**8**		7
Unrealized loss on derivative financial liabilities		**—**		(1)
Net finance expense	**$**	**284**	$	340

a. For the year ended December 31, 2020, debt extinguishment expense related to the refinancing of the 7.00% senior unsecured notes due March 2024 included a cumulative debt redemption premium of $9 million and associated unamortized deferred debt issue costs of $3 million. Refer to Note 10 for further details.

b. For the year ended December 31, 2019, debt extinguishment expense included a cumulative debt redemption premium of $29 million and associated unamortized deferred debt issue costs of $10 million as well as a $4 million premium paid on the repurchase of the senior secured second lien notes and related unamortized deferred debt issue costs of $3 million. Refer to Note 10 for further details.

19. OTHER EXPENSES

Year ended December 31		2020		2019
Contract cancellation[(i)]	$	**33**		—
Onerous contract expense[(ii)]		**25**		—
Severance and restructuring		**10**		11
Research and development		**—**		12
Other expenses	$	**68**	$	23

(i) Costs incurred to mitigate rail sales contract exposure.

(ii) Onerous contract expense is the total future cash flows related to the Corporation's onerous marketing contract.

20. OTHER INCOME

Year ended December 31		2020		2019
Gain on asset disposition[(i)]	$	**(6)**	$	(14)
Contract cancellation[(ii)]		**—**		(20)
Other income	$	**(6)**	$	(34)

(i) As per Note 9, the Corporation sold patents during the year ended December 31, 2020 and sold internally generated emission performance credits during the year ended December 31, 2019.

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

21. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the years ended December 31, 2020 and 2019, other than compensation of key management personnel. The Corporation considers directors and officers of the Corporation as key management personnel.

Year ended December 31		2020		2019
Share-based compensation	$	**6**	$	19
Salaries and short-term employee benefits		**5**		4
Termination benefits		**—**		1
	$	**11**	$	24

The decrease in share-based compensation to key management personnel in 2020 is mainly due to the decline in the Corporation's share price and its impact on the value of the share-based awards.

22. SUPPLEMENTAL CASH FLOW DISCLOSURES

Year ended December 31		2020		2019
Cash provided by (used in):				
Trade receivables and other	**$**	**102**	$	(173)
Inventories		**13**		3
Accounts payable and accrued liabilities		**(101)**		40
Interest payable		**3**		(10)
	$	**17**	$	(140)
Changes in non-cash working capital relating to:				
Operating	**$**	**63**	$	(110)
Investing		**(46)**		(30)
	$	**17**	$	(140)
Cash and cash equivalents:[(a)]				
Cash	**$**	**114**	$	206
Cash equivalents		**—**		—
	$	**114**	$	206
Cash interest paid	**$**	**213**	$	239

a. As at December 31, 2020, $104 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (December 31, 2019 – $135 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2755 (December 31, 2019 – US$1=C$1.2965).

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

	Finance sublease receivables	Lease liabilities	Long-term debt
Balance as at December 31, 2019	$ 18	$ 281	$ 3,123
Cash changes:			
Receipts on leased assets	(1)	—	—
Payments on leased liabilities	—	(26)	—
Issue of 7.125% senior unsecured notes	—	—	1,581
Repayment and redemption of long-term debt	—	—	(1,723)
Debt redemption premium and refinancing costs	—	—	(49)
Non-cash changes:			
Lease liabilities settled		(21)	
Lease liabilities incurred	—	19	—
Lease liabilities modified	—	7	—
Interest expense on lease liabilities	—	26	—
Unrealized (gain) loss on foreign exchange	—	—	(36)
Debt redemption premium	—	—	12
Amortization of deferred debt discount and debt issue costs	—	—	4
Balance as at December 31, 2020	**$ 17**	**$ 286**	**$ 2,912**

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

23. NET EARNINGS (LOSS) PER COMMON SHARE

Year ended December 31	**2020**	**2019**
Net loss	**$ (357)**	$ (62)
Weighted average common shares outstanding (millions)[a]	**302**	299
Dilutive effect of stock options, RSUs and PSUs (millions)[b]	**—**	—
Weighted average common shares outstanding – diluted (millions)	**302**	299
Net earnings (loss) per share, basic	**$ (1.18)**	$ (0.21)
Net earnings (loss) per share, diluted	**$ (1.18)**	$ (0.21)

a. Weighted average common shares outstanding for the year ended December 31, 2020 includes 360,543 PSUs vested but not yet released (year ended December 31, 2019 - 381,014 PSUs).

b. For the year ended December 31, 2020, the Corporation incurred a net loss and therefore there was no dilutive effect of stock options, RSUs and PSUs. If the Corporation had recognized net earnings for the year ended December 31, 2020, the dilutive effect of stock options, RSUs and PSUs would have been 3.8 million weighted average common shares (year ended December 31, 2019 - 3.0 million weighted average common shares).

24. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

a. Fair values:

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

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

As at December 31	2020		2019	
	Carrying amount	Fair value	Carrying amount	Fair value
Recurring measurements:				
Financial assets				
Risk management contracts	**$ 27**	**$ 27**	$ —	$ —
Financial liabilities				
Long-term debt (Note 10)	**$ 2,929**	**$ 3,019**	$ 3,107	$ 3,160
Risk management contracts	**$ 29**	**$ 29**	$ 77	$ 77

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker. The fair value was determined based on estimates as at December 31, 2020 and is expected to fluctuate given the volatility in the debt and commodity price markets.

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

b. Commodity risk management:

The Corporation's risk management assets and liabilities consist of WTI swaps and put options, light-heavy crude oil differential swaps, condensate swaps, natural gas swaps and equity swaps. The use of the financial risk management contracts is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes. Financial risk management contracts are measured at fair value, with gains and losses on re-measurement included in the consolidated statement of earnings and comprehensive income in the period in which they arise.

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

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

As at December 31	2020			2019		
	Asset	Liability	Net	Asset	Liability	Net
Gross amount	**$ 27**	**$ (62)**	**$ (35)**	$ —	$ (77)	$ (77)
Amount offset	**—**	**33**	**33**	—	—	—
Net amount	**$ 27**	**$ (29)**	**$ (2)**	$ —	$ (77)	$ (77)
Current portion	**$ 6**	**$ (29)**	**$ (23)**	$ —	$ (77)	$ (77)
Non-current portion	**21**	**—**	**21**	—	—	—
Net amount	**$ 27**	**$ (29)**	**$ (2)**	$ —	$ (77)	$ (77)

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

As at December 31	2020	2019
Fair value of contracts, beginning of year	**$ (77)**	$ 93
(Gain) loss on fair value of contracts realized	**(343)**	113
Change in fair value of contracts(i)	**418**	(283)
Fair value of contracts, end of period	**$ (2)**	$ (77)

(i) As at December 31, 2020 this amount includes the change in the fair value of the equity price risk management contracts of $26 million.

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

As at December 31, 2020			
Crude Oil Sales (Purchase) Contracts	**Volumes (bbls/d)(i)**	**Term**	**Average Price (US$/bbl)(i)**
WTI(ii) Fixed Price	21,200	Jan 1, 2021 - Mar 31, 2021	$46.73
WTI Fixed Price	13,000	Apr 1, 2021 - Jun 30, 2021	$46.31
WTI:WCS(iii) Fixed Differential	968	Jan 1, 2021 - Jan 31, 2021	$(10.90)
WTI:WCS (USGC) Fixed Differential	(1,071)	Feb 1, 2021 - Feb 28, 2021	$(2.50)
Enhanced Fixed Price with Sold Put Option			
WTI Fixed Price/Sold Put Option Strike Price	29,000	Jan 1, 2021 - Dec 31, 2021	$46.18/$38.79
Condensate Purchase Contracts			
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	$(11.30)
Natural Gas Purchase Contracts	**Volumes (GJ/d)(i)**	**Term**	**Average Price (C$/GJ)(i)**
AECO Fixed Price	38,733	Jan 1, 2021 - Dec 31, 2021	$2.60

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

(ii) West Texas Intermediate ("WTI") crude oil

(iii) Western Canadian Select ("WCS") crude oil blend

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

Subsequent to December 31, 2020			
Crude Oil Sales Contracts	**Volumes (bbls/d)(i)**	**Term**	**Average Price (US$/bbl)(i)**
WTI Fixed Price	16,161	Jan 1, 2021 - Mar 31, 2021	$50.35
WTI:WCS Fixed Differential	15,000	Mar 1, 2021 - Mar 31, 2021	$(13.62)
WTI:WCS Fixed Differential	28,000	Apr 1, 2021 - Jun 30, 2021	$(12.26)
WTI:WCS Fixed Differential	4,000	Jul 1, 2021 - Sep 30, 2021	$(11.18)

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

The Corporation had the following physical commodity risk management contracts relating to crude oil sales, condensate purchases, natural gas purchases and power sales outstanding as at March 3, 2021:

Crude Oil Sales Contracts	**Volumes (bbls/d)(i)**	**Term**	**Average Price (US$/bbl)(i)**
WTI:AWB Fixed Differential	15,000	Feb 1, 2021 - Jun 30, 2021	$(17.65)
Condensate Purchase Contracts			
WTI:Condensate Fixed Differential	4,490	Jan 1, 2021 - Dec 31, 2021	$(1.29)
Natural Gas Purchase Contracts	**Volumes (GJ/d)(i)**	**Term**	**Average Price (C$/GJ)(i)**
AECO Fixed Price	7,500	Jan 1, 2021 - Dec 31, 2021	$2.71
Power Sales Contracts	**Quantity (MWh)(i)**	**Term**	**Average Price (C$/MW)(i)**
Fixed Price	34	Feb 1, 2021 - Dec 31, 2021	$62.80

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

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

Year ended December 31		**2020**		**2019**
Realized loss (gain) on commodity risk management	**$**	**(343)**	$	113
Unrealized loss (gain) on commodity risk management		**(49)**		169
Commodity risk management (gain) loss, net	**$**	**(392)**	$	282

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

Commodity	**Sensitivity Range**		**Increase**		**Decrease**
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	**$**	**(84)**	**$**	**80**
Condensate purchase price	± 5% in condensate price as a percentage of WTI	**$**	**13**	**$**	**(13)**
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	**$**	**11**	**$**	**(11)**

c. 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 entered 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.

The sensitivity of the earnings (loss) before income tax impact of changes in the Corporation's share price on equity price risk management contracts in place at December 31, 2020 is as follows:

	Sensitivity Range	Increase	Decrease
Equity price risk management contracts	± 10% applied to Corporation's share price	**$ 4**	**$ (4)**

d. Credit risk management:

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward looking information to determine the appropriate loss allowance provisions. Credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to each counterparty's credit quality. More than 95% of trade receivables are with investment grade customers in the energy industry and are subject to normal industry credit risk. The Corporation has experienced no material loss in relation to trade receivables. As at December 31, 2020, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $276 million. All amounts receivable from commodity risk management activities are due from large Canadian banks with strong investment grade credit ratings. Counterparty default risk associated with the Corporation's commodity risk management activities is also partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements.

The Corporation's cash balances are used to fund the development of its properties. As a result, the primary objectives of the investment portfolio are low risk capital preservation and high liquidity. The cash balances are held in high interest savings accounts or are invested in high grade, liquid, short-term instruments such as bankers' acceptances, commercial paper, money market deposits or similar instruments. The cash and cash equivalents balance at December 31, 2020 was $114 million. None of the investments are past their maturity or considered impaired. The Corporation's estimated maximum exposure to credit risk related to its cash and cash equivalents is $114 million.

e. Foreign currency risk management:

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the fair value or future cash flows of the Corporation's financial assets or liabilities. The Corporation has U.S. dollar denominated long-term debt as described in Note 10. As at December 31, 2020, a $0.01 change in the U.S. dollar to Canadian dollar exchange rate would have resulted in a change to the carrying value of long-term debt and a corresponding change to earnings (loss) before income tax of C$23 million (December 31, 2019 - C$24 million).

f. Liquidity risk management:

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

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

The Corporation's earliest maturing long-term debt is approximately four years out, represented by US$496 million of 6.5% senior secured second lien notes due January 2025. 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 ratio of 3.5 or less). Under the Corporation's revolving 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.

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

As at December 31, 2020	**Total**	**Less than 1 year**	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Long-term debt[(i)]	$ 2,929	$ —	$ —	$ 1,398	$ 1,531
Interest on long-term debt	$ 1,010	204	408	276	122
Commodity risk management contracts	$ 29	29	—	—	—
Accounts payable and accrued liabilities	$ 279	279	—	—	—
	$ 4,247	$ 512	$ 408	$ 1,674	$ 1,653

(i) *These debt maturities do not reflect the refinancing associated with the US$600 million private offering which closed on February 2, 2021. Please refer to Note 10 for further details.*

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

25. GEOGRAPHICAL DISCLOSURE

As at December 31, 2020, the Corporation had non-current assets related to operations in the United States of $106 million (December 31, 2019 – $102 million). For the year ended December 31, 2020, petroleum revenue related to operations in the United States was $1.4 billion (year ended December 31, 2019 – $1.8 billion).

26. CAPITAL MANAGEMENT

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

On January 31, 2020, the Corporation completed the refinancing and extension of the maturity profile of its debt portfolio. Following completion of the associated transactions, MEG's first debt maturity was extended to 2024. As at December 31, 2020, the Corporation had $785 million of unutilized capacity under the $800 million revolving credit facility and had $100 million of unutilized capacity under the $500 million letter of credit facility. A letter of credit of $15 million was issued under its revolving credit facility during the year ended December 31, 2020.

The following table summarizes the Corporation's net debt:

As at December 31	**Note**	**2020**	**2019**
Long-term debt	10	**$ 2,912**	$ 3,123
Cash and cash equivalents		**(114)**	(206)
Net debt		**$ 2,798**	$ 2,917

Net debt is an important measure used by management to analyze leverage and liquidity. During the year ended December 31, 2020, net debt decreased by $119 million due to the partial redemption of the Corporation's 6.5% senior secured second lien notes and the strengthening of the Canadian dollar relative to the U.S. dollar, partially offset by the decrease in cash and cash equivalents.

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

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

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

Subsequent to December 31, 2020, on February 2, 2021, the Corporation successfully closed on a private offering of US$600 million in aggregate principal amount of 5.875% senior unsecured notes due February 2029. The net proceeds of the offering, together with cash-on-hand, were used to fully redeem US$600 million in aggregate principal amount of the 7.00% senior unsecured notes due March 2024 at a redemption price of 101.167% and to pay fees and expenses related to the offer.

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

Year ended December 31	Note	2020	2019
Net cash provided by (used in) operating activities		**$ 302**	$ 631
Net change in non-cash operating working capital items		**(63)**	110
Funds flow from (used in) operations		**239**	741
Adjustments:			
Contract cancellation(i)	19,20	**33**	(20)
Decommissioning expenditures	11	**3**	2
Net change in other liabilities(ii)		**3**	3
Adjusted funds flow		**$ 278**	$ 726

(i) During 2020 these costs were incurred to mitigate rail sales contract exposure. The economic decision to divert sales volumes from rail contracts at Edmonton to the USGC more than recovered the cost of contract cancellations. During the fourth quarter of 2019, the Corporation agreed to relieve the Alberta Petroleum Marketing Commission of all obligations pursuant to a crude oil purchase and sale agreement in exchange for a payment of $20 million. Contract cancellation costs or recoveries are excluded from adjusted funds flow as they are not considered part of ordinary continuing operating results.

(ii) Includes the change in liability associated with the termination of a long-term transportation contract that was previously expensed.

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

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

27. COMMITMENTS AND CONTINGENCIES

a. Commitments

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

	2021	2022	2023	2024	2025	Thereafter	Total
Transportation and storage(i)	$ 397	$ 411	$ 454	$ 440	$ 413	$ 5,598	$ 7,713
Diluent purchases	152	21	17	—	—	—	190
Other operating commitments	24	16	16	13	13	36	118
Variable office lease costs	4	4	4	5	5	26	48
Capital commitments	12	—	—	—	—	—	12
Commitments	**$ 589**	**$ 452**	**$ 491**	**$ 458**	**$ 431**	**$ 5,660**	**$ 8,081**

(i) This represents transportation and storage commitments from 2021 to 2048, including the Access Pipeline TSA, and pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet (Note 11(a)).

b. Contingencies

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

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

MEG Energy

Sustainable. Innovative. Responsible.

megenergy.com