SECOND QUARTER | 2021

REPORT TO SHAREHOLDERS FOR THE
PERIOD ENDED JUNE 30, 2021

# Report to Shareholders for the period ended June 30, 2021

(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 second quarter 2021 operational and financial results on July 22, 2021.

MEG continues to proactively respond to the safety challenges associated with the COVID-19 pandemic and remains committed to ensuring the health and safety of all of its personnel and the safe and reliable operation of the Christina Lake facility.

“The second quarter was another strong operational quarter for MEG, giving us the confidence to increase our full year 2021 production guidance and begin the work to bring our Christina Lake facility back up to full operational utilization and re-initiate debt reduction” said Derek Evans, President and Chief Executive Officer. “Today we announced the redemption of approximately $125 million of debt and are committed to applying all free cash flow generated in the second half of 2021 to debt reduction.”

Second quarter financial and operating highlights include:

- Adjusted funds flow of $166 million ($0.53 per share), impacted by a realized commodity price risk management loss in the quarter of $87 million ($0.28 per share);
- Quarterly production volumes of 91,803 barrels per day (bbls/d) at a steam-oil ratio (SOR) of 2.39. Based on strong operational performance, annual average production guidance has been upwardly revised from 88,000 – 90,000 bbls/d to 91,000 – 93,000 bbls/d;
- Net operating costs of $5.54 per barrel, including non-energy operating costs of $3.84 per barrel. Power revenue offset energy operating costs by 60%, resulting in a net impact of $1.70 per barrel;
- Sale of non-core industrial lands near Edmonton for cash proceeds of approximately $44 million;
- Total capital investment of $70 million in the quarter was directed to sustaining and maintenance capital, resulting in $96 million of free cash flow in the quarter and $153 million of free cash flow in the first half of 2021;
- In June 2021 MEG along with four other oil sands operators who collectively represent 90% of Canada’s oil sands production formed the Oil Sands Pathway to Net Zero Alliance to work collectively with the federal and Alberta governments to achieve net zero GHG emissions from oil sands operations by 2050; and
- Subsequent to the quarter, MEG issued a notice to redeem US$100 million (approximately C$125 million) of MEG’s 6.50% senior secured second lien notes due January 2025.

## Blend Sales Pricing

MEG realized an average AWB blend sales price of US$56.41 per barrel during the second quarter of 2021 compared to US$48.39 per barrel in the first quarter of 2021. The increase in average AWB blend sales price quarter over quarter was primarily a result of the average WTI price increasing by US$8.23 per barrel. MEG sold 45% of its sales volumes at the premium-priced U.S. Gulf Coast ("USGC") in the second quarter of 2021 compared to 38% in the first quarter of 2021.

As sales volumes were consistent quarter over quarter, transportation and storage costs were also consistent averaging US$6.17 per barrel of AWB blend sales in the second quarter of 2021 compared to US$6.13 per barrel of AWB blend sales in the first quarter of 2021.

## Operational Performance

Bitumen production averaged 91,803 bbls/d in the second quarter of 2021, consistent with average bitumen production of 90,842 bbls/d in the first quarter of 2021.

Non-energy operating costs averaged $3.84 per barrel of bitumen sales in the second quarter of 2021 compared to $4.05 per barrel in the first quarter of 2021 primarily due to a 3% increase in bitumen sales volumes quarter over quarter. Energy operating costs, net of power revenue, averaged $1.70 per barrel in the second quarter of 2021 compared to $1.20 per barrel in the first quarter of 2021. MEG benefited from strong power prices on power sales from its cogeneration facilities whereby power revenue offset energy operating costs by 60% during the second quarter of 2021.

General & administrative expense ("G&A") was $13 million, or $1.56 per barrel of production, in the second quarter of 2021 compared to $14 million, or $1.77 per barrel of production, in the first quarter of 2021. The difference in per barrel G&A expense was due to higher production in the second quarter of 2021 compared to the first quarter of 2021.

## Adjusted Funds Flow and Net Earnings (Loss)

MEG's bitumen realization averaged $60.09 per barrel in the second quarter of 2021 compared to $52.34 per barrel in the first quarter of 2021. The increase in average bitumen realization was due to the higher WTI price quarter over quarter. Partially offsetting the increase in bitumen realization during the second quarter of 2021, compared to the first quarter of 2021, was a realized commodity price risk management loss of $10.63 per barrel in the second quarter of 2021 compared to $8.80 per barrel in the first quarter of 2021. This reflects stronger WTI settlement prices compared to WTI fixed price contracts in place.

The Corporation's cash operating netback averaged $31.30 per barrel in the second quarter of 2021 compared to $26.03 per barrel in the first quarter of 2021. The increased cash operating netback drove the increase in the Corporation's adjusted funds flow from $127 million in the first quarter of 2021 to $166 million in the second quarter of 2021.

The Corporation recognized net earnings of $68 million in the second quarter of 2021 compared to a net loss of $17 million in the first quarter of 2021. This change was primarily the result of increased cash operating netback and a smaller unrealized loss on commodity price risk management.

## Capital Expenditures

MEG invested $70 million in the second quarter of 2021 compared to $70 million in the first quarter of 2021, which was primarily directed towards sustaining and maintenance activities during both periods.

## COVID-19 Global Pandemic

MEG continues to proactively respond to the safety challenges associated with COVID-19 and remains committed to ensuring that the health and safety of all its personnel and business partners and the safe and reliable operation of the Christina Lake facility remain a top priority. MEG continues to apply screening procedures, including antigen screening and other protocols, ensuring the health and safety of its people.

### Non-Core Asset Sale

During the quarter, MEG completed the sale of non-core industrial lands near Edmonton for cash proceeds of approximately $44 million, with proceeds received in July. The lands were purchased in 2013 at a cost of $39 million.

### Optimization of Christina Lake Production Capacity

Inclusive of the non-core asset sale, MEG generated approximately $200 million of cash in excess of invested capital in the first half of 2021. Of this amount, the Corporation will direct $75 million to MEG’s 2021 capital investment program.

This $75 million of capital investment represents the majority of the estimated $125 million incremental well capital necessary to allow the Corporation to fully utilize the Christina Lake central plant facility’s oil processing capacity of approximately 100,000 bbls/d, prior to any impact from scheduled maintenance activity or outages.

The estimated $125 million total cost is less than MEG’s previous estimate of $150 million due to year-to-date field-wide production outperformance resulting from increased steam utilization, improved field reliability and completed and ongoing well optimization and recompletion work. This year-to-date outperformance provides the confidence for the Corporation to increase full year 2021 average production guidance from 88,000 – 90,000 bbls/d to 91,000 – 93,000 bbls/d.

MEG expects to invest the estimated $50 million of remaining incremental well capital required to return the Christina Lake facility to full utilization in the first half of 2022. Based on this level of incremental capital investment the Corporation expects to be able to fully utilize the oil processing capacity at its Christina Lake facility in the second half of 2022 post the planned turnaround at MEG’s Phase 2B facility in the second quarter of 2022. The turnaround, which is scheduled for the month of May 2022, is currently expected to impact full year 2022 production by approximately 5,000 bbls/d.

### Debt Repayment

MEG announced today that the Corporation has issued a notice to redeem US$100 million (approximately C$125 million) of MEG’s 6.50% senior secured second lien notes due January 2025 at a redemption price of 103.25%, plus accrued and unpaid interest to, but not including, the redemption date. The redemption is expected to be completed on or about August 23, 2021.

Based on the current commodity price environment, MEG anticipates generating approximately $275 million of free cash flow in the second half of 2021, which will be directed to further debt repayment.

### Outlook

Based on better than expected production performance in the first half of 2021, MEG is revising its full year 2021 average production to 91,000 – 93,000 bpd.

G&A expense is now targeted to be in the range of $1.65 - $1.75 per barrel and non-energy operating costs are now expected to be in the range of $4.40 - $4.60 per barrel.

| Summary of 2021 Guidance | Revised Guidance (July 22, 2021) | Revised Guidance (May 3, 2021) | Original Guidance (December 7, 2020) |
|---|---|---|---|
| Bitumen production - annual average | 91,000 - 93,000 bbls/d | 88,000 - 90,000 bbls/d | 86,000 - 90,000 bbls/d |
| Non-energy operating costs | $4.40 - $4.60 per bbl | $4.60 - $5.00 per bbl | $4.60 - $5.00 per bbl |
| G&A expense | $1.65 - $1.75 per bbl | $1.70 - $1.80 per bbl | $1.70 - $1.80 per bbl |
| Capital expenditures | $335 million | $260 million | $260 million |

MEG is revising downward its expected sales into the USGC via Flanagan South and Seaway Pipeline systems ("FSP") from 50% to approximately 40% of total AWB blend sales. This is lower than previous estimates due to continued higher than forecast apportionment on the Enbridge mainline system. As a result, MEG is revising downward its estimate of full year 2021 total transportation costs from a range of US$6.75 to US$7.25 per barrel of AWB blend sales to a range of US$6.00 to US$6.50 per barrel of AWB blend sales.

### 2021 Commodity Price Risk Management

In the second half of 2020, MEG entered into enhanced WTI fixed price hedges with sold put options for approximately 30% of forecast second half of 2021 bitumen production at an average price of US$46.18 per barrel. MEG has also hedged approximately 15% of its forecast Edmonton WTI:WCS differential exposure for the third quarter of 2021 at an average differential of US$11.05 per barrel. In addition, MEG has hedged approximately 35% of its expected condensate requirements at a landed-at-Edmonton price of 97% of WTI, approximately 30% of expected natural gas requirements at an average price of C$2.61 per GJ and fixed the sales price on approximately 30% of expected power available for sale at an average price of C$62.75 per MWh, each for the second half of 2021. The table below reflects MEG's outstanding 2021 hedge positions.

| | Forecast Period | |
|---|---|---|
| | **Q3 2021** | **Q4 2021** |
| **WTI Hedges** | | |
| Enhanced WTI Fixed Price Hedges with Sold Put Options(1) | | |
| Volume (bbls/d) | 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 |
| **WTI:WCS Differential Hedges** | | |
| Volume (bbls/d) | 10,000 | — |
| Weighted average fixed WTI:WCS differential (US$/bbl) | $ (11.05) | $ — |
| **Condensate Hedges** | | |
| Volume(2) (bbls/d) | 14,028 | 14,028 |
| Weighted average % of WTI landed in Edmonton (%)(3) | 97 % | 97 % |
| **Natural Gas Hedges** | | |
| Volume(4) (GJ/d) | 42,500 | 42,500 |
| Weighted average fixed AECO price (C$/GJ) | $ 2.61 | $ 2.61 |
| **Power Hedges** | | |
| Quantity(5) (MW) | 35 | 35 |
| Weighted average fixed price (C$/MWh) | $ 62.75 | $ 62.75 |

(1) *If in any month the 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 the 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 approximately 3,000 bbls/d of physical forward condensate purchases for the second half of 2021 at a fixed discount to WTI.*
(3) *The average % of WTI landed in Edmonton includes estimated net transportation costs to Edmonton.*
(4) *Includes 5,000 GJ/d of physical forward natural gas purchases for the second half of 2021 at a fixed AECO price.*
(5) *Represents physical forward power sales at a fixed power price.*

## ADVISORY

### Forward-Looking Information

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

## Non-GAAP Measures

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

## Free Cash Flow

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

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2021** | **2020** | **2021** | **2020** |
| Net cash provided by (used in) operating activities | **$ 180** | $ 117 | **$ 192** | $ 216 |
| Net change in non-cash operating working capital items | **(20)** | (48) | **89** | (78) |
| Funds flow from operations | **160** | 69 | **281** | 138 |
| Adjustments: | | | | |
| Payments on onerous contracts | **6** | — | **12** | — |
| Contract cancellation | **—** | 20 | **—** | 26 |
| Adjusted funds flow | **$ 166** | $ 89 | **$ 293** | $ 164 |
| Capital expenditures | **(70)** | (20) | **(140)** | (74) |
| Free cash flow | **$ 96** | $ 69 | **$ 153** | $ 90 |

## Cash Operating Netback

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

# MANAGEMENT'S DISCUSSION AND ANALYSIS

*This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three and six months ended June 30, 2021 was approved by the Corporation's Audit Committee on July 22, 2021. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three and six months ended June 30, 2021, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2020, the 2020 annual MD&A and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in millions of Canadian dollars, except where otherwise indicated.*

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

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## 1. BUSINESS DESCRIPTION

MEG is an energy company focused on sustainable in situ thermal oil production in the southern Athabasca 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 400 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.

## 2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The Corporation generated adjusted funds flow of $166 million in the second quarter of 2021 compared to $89 million in the second quarter of 2020, an 87% increase, supported largely by stronger global crude oil prices and structural improvements in WTI:AWB differentials. The Corporation's blend sales price averaged $69.27 per barrel in the second quarter of 2021 compared to $20.96 per barrel in the second quarter of 2020 resulting primarily from a 137% increase in the WTI benchmark price. This was partially offset by the Corporation's losses on commodity price risk management contracts which were in place to protect the internal funding of the Corporation's 2021 capital program.

Production volumes averaged 91,803 barrels per day in the second quarter of 2021. Increased steam utilization, improved field reliability, completed and ongoing well optimization and recompletion work all contributed to strong field-wide production performance in the first half of 2021. As a result, annual production guidance for 2021 increased to 91,000 to 93,000 barrels per day from 88,000 to 90,000 barrels per day.

Total capital spending of $70 million during the second quarter of 2021 compared to $20 million during the second quarter of 2020 was primarily focused on sustaining and maintenance capital. The increase in capital spending reflects the increased annual capital budget compared to 2020, as some capital was shifted to 2021 from 2020 in response to the economic environment associated with the COVID-19 global pandemic ("COVID-19").

The Corporation recognized net earnings of $68 million in the second quarter of 2021 compared to a net loss of $80 million in the second quarter of 2020. Increased earnings were mainly due to stronger global crude oil prices partially offset by a higher commodity price risk management loss as a result of stronger forward commodity prices.

During the second quarter of 2021, the Corporation completed the sale of non-core industrial lands near Edmonton for proceeds of approximately $44 million.

On July 22, 2021, the Corporation announced that it had issued a notice to redeem US$100 million (approximately C$125 million) of the Corporation's 6.50% senior secured second lien notes due January 2025 at a redemption price of 103.25%, plus accrued and unpaid interest to, but not including, the redemption date. The redemption is expected to be completed on or about August 23, 2021.

### COVID-19 Response

The Corporation continues to proactively respond to the safety challenges associated with COVID-19 and remains committed to ensuring that the health and safety of all its personnel and business partners and the safe and reliable operation of the Christina Lake facility remain a top priority. The Corporation continues to apply screening procedures, including antigen screening and other protocols, ensuring the health and safety of its people.

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

| | Six months ended June 30 | | 2021 | | 2020 | | | | 2019 | |
|---|---|---|---|---|---|---|---|---|---|---|
| *($millions, except as indicated)* | **2021** | **2020** | **Q2** | **Q1** | **Q4** | **Q3** | **Q2** | **Q1** | **Q4** | **Q3** |
| Bitumen production - bbls/d | **91,326** | **83,622** | **91,803** | 90,842 | 91,030 | 71,516 | 75,687 | 91,557 | 94,566 | 93,278 |
| Steam-oil ratio | **2.38** | **2.31** | **2.39** | 2.37 | 2.31 | 2.36 | 2.32 | 2.31 | 2.27 | 2.26 |
| Bitumen sales - bbls/d | **88,646** | **83,806** | **89,980** | 87,298 | 95,731 | 67,569 | 70,397 | 97,214 | 94,347 | 94,992 |
| Bitumen realization - $/bbl | **56.30** | **15.56** | **60.09** | 52.34 | 38.64 | 39.68 | 10.18 | 19.45 | 46.86 | 53.37 |
| Net operating costs - $/bbl(1) | **5.39** | **5.78** | **5.54** | 5.25 | 6.98 | 6.05 | 6.14 | 5.51 | 5.87 | 4.30 |
| Non-energy operating costs - $/bbl | **3.94** | **4.37** | **3.84** | 4.05 | 4.70 | 3.96 | 4.09 | 4.57 | 4.49 | 4.22 |
| Cash operating netback - $/bbl(2) | **28.73** | **20.62** | **31.30** | 26.03 | 18.66 | 16.58 | 25.84 | 16.83 | 28.33 | 32.44 |
| General & administrative expense $/bbl(3) | **1.66** | **1.66** | **1.56** | 1.77 | 1.65 | 1.50 | 1.29 | 1.96 | 2.25 | 1.66 |
| Adjusted funds flow(4) | **293** | **164** | **166** | 127 | 84 | 26 | 89 | 76 | 155 | 191 |
| Per share, diluted | **0.95** | **0.54** | **0.53** | 0.41 | 0.27 | 0.09 | 0.29 | 0.25 | 0.51 | 0.63 |
| Revenue | **1,923** | **972** | **1,009** | 914 | 786 | 533 | 307 | 665 | 992 | 958 |
| Net earnings (loss) | **51** | **(364)** | **68** | (17) | 16 | (9) | (80) | (284) | 26 | 24 |
| Per share, diluted | **0.17** | **(1.21)** | **0.22** | (0.06) | 0.05 | (0.03) | (0.26) | (0.95) | 0.09 | 0.08 |
| Capital expenditures | **140** | **74** | **70** | 70 | 40 | 36 | 20 | 54 | 72 | 40 |
| Cash and cash equivalents | **159** | **120** | **159** | 54 | 114 | 49 | 120 | 62 | 206 | 154 |
| Long-term debt - C$ | **2,820** | **3,096** | **2,820** | 2,852 | 2,912 | 3,030 | 3,096 | 3,212 | 3,123 | 3,257 |
| Long-term debt - US$ | **2,273** | **2,274** | **2,273** | 2,268 | 2,283 | 2,274 | 2,274 | 2,275 | 2,409 | 2,459 |

(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) *General and administrative expense ("G&A") per barrel is based on bitumen production volumes.*
(4) *Refer to Note 19 of the interim consolidated financial statements for further details.*

## 3. SUSTAINABILITY

The Corporation's approach to environmental, social and governance ("ESG") matters and 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, the Corporation'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, the Corporation is focused on enhancing its position as a sustainable low-cost producer and achieving net zero carbon emissions.

During the second quarter of 2021, the Corporation, along with four oil sands operators that collectively represent 90% of Canada's oil sands production, formed the Oil Sands Pathway to Net Zero Alliance to work collectively with the federal and Alberta governments to achieve net zero GHG emissions from oil sands operations by 2050. This collective action to create strategies and economically invest in infrastructures and technologies demonstrates the Canadian oil sands' commitment to reduce GHG emissions to net zero and drive solutions for environmentally responsible energy production.

The Corporation plans to publish its 2020 ESG report during the third quarter of 2021.

For further details on the Corporation’s approach, please refer to the 2020 annual MD&A and most recently filed Annual Information Form on www.sedar.com.

## 4. RESULTS OF OPERATIONS

### Bitumen Production and Steam-Oil Ratio

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Bitumen production – bbls/d | **91,803** | 75,687 | **91,326** | 83,622 |
| Steam-oil ratio (SOR) | **2.39** | 2.32 | **2.38** | 2.31 |

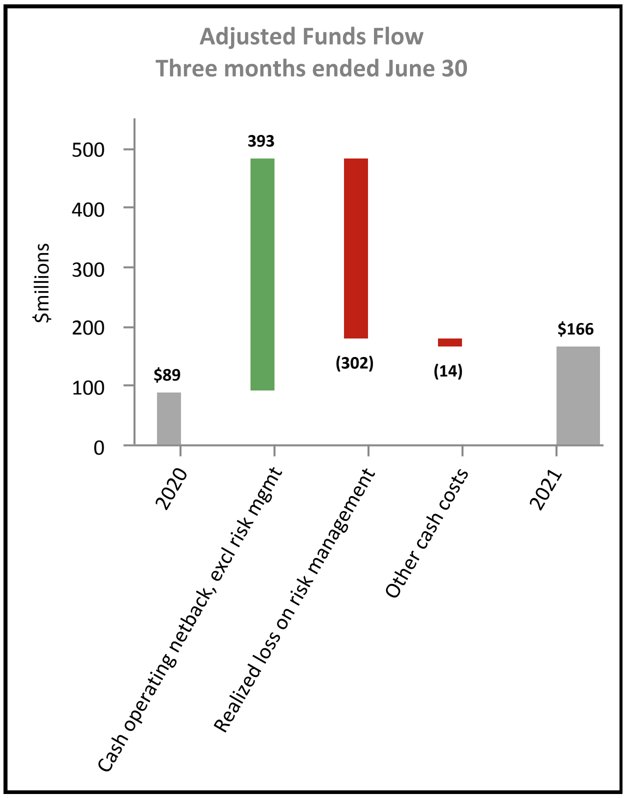
### Bitumen Production

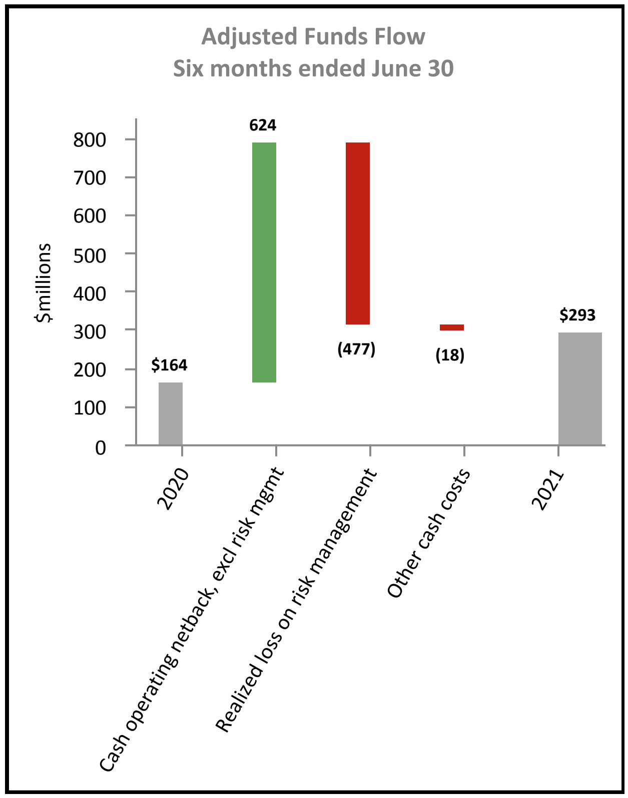
Bitumen production increased 21% and 9% during the three and six months ended June 30, 2021 compared to the same periods of 2020. Increased steam utilization, improved field reliability, completed and ongoing well optimization and recompletion work all contributed to strong field-wide production performance in the first half of 2021. This compares to reduced bitumen production in 2020 due to the major planned turnaround at the Phase 1 and 2 facilities, which began in June 2020, as well as voluntary price-related production curtailments in April and May 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 three and six months ended June 30, 2021, compared to the same periods of 2020, due to the timing of new well pairs and wells being brought into steam circulation and production.

### Adjusted Funds Flow




During the three and six months ended June 30, 2021, adjusted funds flow increased compared to the same periods of 2020, driven by the Corporation's increased cash operating netback which was impacted by an increase in global crude oil prices partially offset by realized losses on commodity price risk management contracts. The commodity price risk management contracts were put in place to protect funding of the Corporation's 2021 capital program which is expected to be fully funded with internally generated cash flow.

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

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2021** | **2020** | **2021** | **2020** |
| Net cash provided by (used in) operating activities | **$ 180** | $ 117 | **$ 192** | $ 216 |
| Net change in non-cash operating working capital items | **(20)** | (48) | **89** | (78) |
| Funds flow from operations | **160** | 69 | **281** | 138 |
| Adjustments: | | | | |
| Payments on onerous contracts | **6** | — | **12** | — |
| Contract cancellation | **—** | 20 | **—** | 26 |
| Adjusted funds flow | **$ 166** | $ 89 | **$ 293** | $ 164 |

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

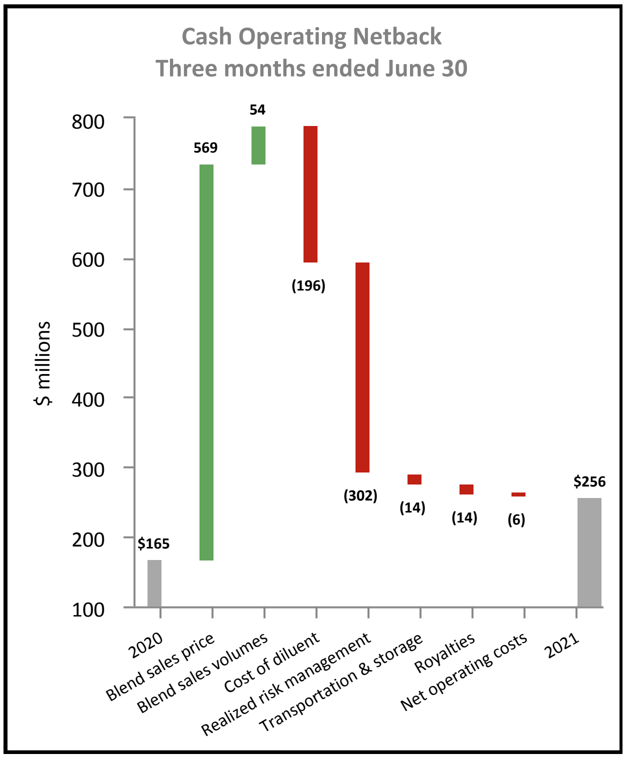
### Cash Operating Netback

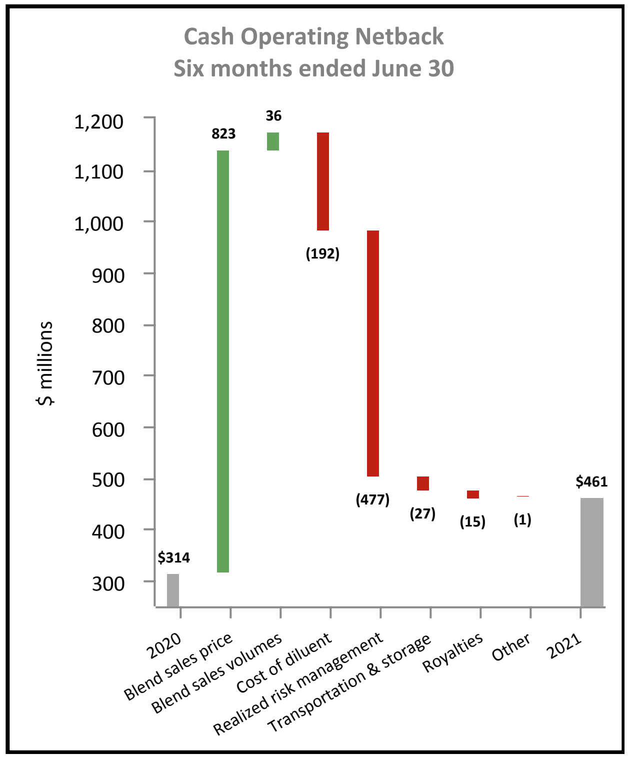
The following table summarizes the Corporation's cash operating netback. Unless otherwise indicated, the per barrel calculation for the periods indicated below are based on bitumen sales volume.

| | Three months ended June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | **2021** | | 2020 | | **2021** | | 2020 | |
| *($millions, except as indicated)* | | **$/bbl** | | **$/bbl** | | **$/bbl** | | **$/bbl** |
| Sales from production | **$ 813** | | $ 181 | | **$ 1,508** | | $ 650 | |
| Sales from purchased product[1] | **187** | | 118 | | **385** | | 297 | |
| Petroleum revenue | **1,000** | | 299 | | **1,893** | | 947 | |
| Purchased product[1] | **(184)** | | (106) | | **(369)** | | (282) | |
| Blend sales[2] | **$ 816** | **$ 69.27** | $ 193 | $ 20.96 | **$ 1,524** | **$ 65.32** | $ 665 | $ 30.03 |
| Cost of diluent | **(324)** | **(9.18)** | (128) | (10.78) | **(620)** | **(9.02)** | (428) | (14.47) |
| Bitumen realization | **492** | **60.09** | 65 | 10.18 | **904** | **56.30** | 237 | 15.56 |
| Transportation and storage[3] | **(89)** | **(10.91)** | (75) | (11.77) | **(179)** | **(11.15)** | (152) | (9.96) |
| Third-party curtailment credits[4] | **—** | **—** | — | — | **—** | **—** | 2 | 0.11 |
| Royalties | **(14)** | **(1.71)** | — | (0.05) | **(21)** | **(1.29)** | (6) | (0.37) |
| Net operating costs | **(46)** | **(5.54)** | (40) | (6.14) | **(87)** | **(5.39)** | (88) | (5.78) |
| Cash operating netback - excluding realized commodity risk management | **343** | **41.93** | (50) | (7.78) | **617** | **38.47** | (7) | (0.44) |
| Realized gain (loss) on commodity risk management | **(87)** | **(10.63)** | 215 | 33.62 | **(156)** | **(9.74)** | 321 | 21.06 |
| Cash operating netback[5] | **$ 256** | **$ 31.30** | $ 165 | $ 25.84 | **$ 461** | **$ 28.73** | $ 314 | $ 20.62 |
| Bitumen sales volumes - bbls/d | | **89,980** | | 70,397 | | **88,646** | | 83,806 |

*(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) During 2020, the Corporation had the ability to 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 asset optimization activities undertaken in the period. Marketing asset optimization is 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 to facilitate asset optimization activities 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 U.S. Gulf Coast ("USGC") markets, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar. The cost of diluent purchased is partially offset by the sales of such diluent in AWB volumes. Bitumen realization per barrel fluctuates primarily based on average benchmark prices and light:heavy oil differentials.

| | Three months ended June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2021 | | 2020 | | 2021 | | 2020 | |
| *($millions, except as indicated)* | | $/bbl | | $/bbl | | $/bbl | | $/bbl |
| Sales from production | **$ 813** | | $ 181 | | **$ 1,508** | | $ 650 | |
| Sales from purchased product[1] | **187** | | 118 | | **385** | | 297 | |
| Petroleum revenue | **$ 1,000** | | $ 299 | | **$ 1,893** | | $ 947 | |
| Purchased product[1] | **(184)** | | (106) | | **(369)** | | (282) | |
| Blend sales[2] | **$ 816** | **$ 69.27** | $ 193 | $ 20.96 | **$ 1,524** | **$ 65.32** | $ 665 | $ 30.03 |
| Cost of diluent | **(324)** | **(9.18)** | (128) | (10.78) | **(620)** | **(9.02)** | (428) | (14.47) |
| Bitumen realization | **$ 492** | **$ 60.09** | $ 65 | $ 10.18 | **$ 904** | **$ 56.30** | $ 237 | $ 15.56 |

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

Blend sales price increased by $48.31 per barrel and $35.29 per barrel during the three and six months ended June 30, 2021, respectively, compared to the same periods of 2020. The increase in blend sales price during the three and six months ended June 30, 2021 is due to a higher WTI price and a narrower WTI:AWB differential.

During the three and six months ended June 30, 2021, the cost of diluent per barrel decreased 15% and 38%, respectively, compared to the same periods of 2020. The decrease reflects narrower WTI:AWB differentials resulting in a higher recovery of the cost of diluent through blend sales.

The total cost of diluent was $324 million and $620 million during the three and six months ended June 30, 2021, respectively, compared to $128 million and $428 million during the same periods of 2020. This translates to a cost per barrel of diluent during the three and six months ended June 30, 2021 of $90.18 and $85.20, respectively, compared to $45.76 and $62.05 for the same periods of 2020. The cost per barrel is impacted by the benchmark condensate price, transportation costs to move diluent to the Christina Lake production site and the timing of use of inventory. The cost of diluent recognized is determined on a weighted-average cost basis and diluent volumes are typically held in inventory for 30 to 60 days. Approximately half of the diluent is sourced from each of Edmonton and Mont Belvieu, Texas. Refer to condensate prices within the "BUSINESS ENVIRONMENT" section of this MD&A for further details.

### Transportation and Storage

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

| | **Three months ended June 30** | | | | **Six months ended June 30** | | | |
|---|---|---|---|---|---|---|---|---|
| | **2021** | | **2020** | | **2021** | | **2020** | |
| *($millions, except as indicated)* | | **$/bbl** | | **$/bbl** | | **$/bbl** | | **$/bbl** |
| Transportation and storage | **$ (89)** | **$ (10.91)** | $ (75) | $ (11.77) | **$ (179)** | **$ (11.15)** | $ (152) | $ (9.96) |
| Bitumen sales volumes - bbls/d | | **89,980** | | 70,397 | | **88,646** | | 83,806 |

Transportation and storage costs on a per barrel basis decreased during the three months ended June 30, 2021, compared to the same period of 2020, as fixed costs were allocated over higher sales volumes. During the three months ended June 30, 2021, total transportation and storage costs increased by 18% compared to the same period of 2020. The increase is primarily the result of additional transportation costs associated with the increased capacity on Flanagan South and Seaway Pipeline systems ("FSP") beginning in July 2020, partially offset by the absence of rail activity during the three months ended June 30, 2021.

During the six months ended June 30, 2021, total transportation and storage costs and per barrel costs increased compared to the same period of 2020 primarily due to additional transportation costs associated with the increased capacity on FSP beginning in July 2020, partially offset by the absence of rail activity during the six months ended June 30, 2021.

The Corporation partially mitigated the cost of unutilized transportation and storage assets through the purchase and sale of non-proprietary product. These asset optimization activities added $3 million, or $0.25 per barrel, to blend sales during the three months ended June 30, 2021 compared to $12 million, or $1.24 per barrel, during the same period of 2020. These asset optimization activities added $16 million, or $0.66 per barrel, to blend sales during the six months ended June 30, 2021 compared to $15 million, or $0.65 per barrel, during the same period of 2020. The Corporation does not engage in speculative trading. The purchase and sale of third-party products to facilitate asset optimization activities 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.

| | Three months ended June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2021 | | 2020 | | 2021 | | 2020 | |
| *($millions, except as indicated)* | | $/bbl | | $/bbl | | $/bbl | | $/bbl |
| Royalties | **$ (14)** | **$ (1.71)** | $ — | $ (0.05) | **$ (21)** | **$ (1.29)** | $ (6) | $ (0.37) |

The increase in royalties for the three and six months ended June 30, 2021, compared to the same periods of 2020, is the result of the increase 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 overall carbon footprint.

| | Three months ended June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2021 | | 2020 | | 2021 | | 2020 | |
| *($millions, except as indicated)* | | $/bbl | | $/bbl | | $/bbl | | $/bbl |
| Non-energy operating costs | **$ (31)** | **$ (3.84)** | $ (27) | $ (4.09) | **$ (63)** | **$ (3.94)** | $ (67) | $ (4.37) |
| Energy operating costs | **(36)** | **(4.27)** | (19) | (3.00) | **(70)** | **(4.30)** | (47) | (3.09) |
| Power revenue | **21** | **2.57** | 6 | 0.95 | **46** | **2.85** | 26 | 1.68 |
| Net operating costs | **$ (46)** | **$ (5.54)** | $ (40) | $ (6.14) | **$ (87)** | **$ (5.39)** | $ (88) | $ (5.78) |
| Bitumen sales volumes - bbls/d | | **89,980** | | 70,397 | | **88,646** | | 83,806 |
| Average natural gas purchase price (C$/mcf) | | **$ 3.55** | | $ 2.11 | | **$ 3.58** | | $ 2.39 |
| Average realized power sales price (C$/Mwh) | | **$ 88.40** | | $ 28.34 | | **$ 90.96** | | $ 51.67 |

Non-energy operating costs increased for the three months ended June 30, 2021, compared to the same period of 2020. In the second quarter of 2020, the Corporation benefited more from various government led initiatives to assist the industry through unprecedented market volatility associated with COVID-19, which resulted in the collapse of oil prices in 2020. Also during the second quarter of 2020, the Corporation stored more production volumes in inventory to be sold when prices recovered, reducing the production costs recognized in that period.

Non-energy operating costs decreased for the six months ended June 30, 2021, compared to the same period of 2020 mainly as a result of reduced site costs allocated to operations as capital activities increased.

On a per barrel basis, non-energy operating costs decreased for the three and six months ended June 30, 2021, compared to the same periods of 2020 due to the increase in sales volume.

Power revenue offset energy operating costs by 59% and 66% during the three and six months ended June 30, 2021, respectively, compared to 32% and 55% during the same periods of 2020, respectively. Energy operating costs increased predominantly due to the AECO natural gas market strengthening. This was partially offset by the Alberta power market strengthening.

### Realized Gain or Loss on Commodity Risk Management

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

| | Three months ended June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2021 | | 2020 | | 2021 | | 2020 | |
| *($millions, except as indicated)* | | $/bbl | | $/bbl | | $/bbl | | $/bbl |
| Realized gain (loss) on commodity risk management | **$ (87)** | **$ (10.63)** | $ 215 | $ 33.62 | **$ (156)** | **$ (9.74)** | $ 321 | $ 21.06 |

Realized losses recognized on commodity risk management contracts were recognized during the three and six months ended June 30, 2021 primarily due to the increase in the WTI prices during the first half of 2021 compared to the WTI fixed price contracts in place. Conversely, realized gains were recognized during the three and six months ended June 30, 2020 due to the significant weakening in the WTI prices compared to the WTI fixed price contracts in place at that time. Refer to the commodity risk management discussion within the "OTHER OPERATING RESULTS" section of this MD&A for further details.

### Marketing Activity

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

| **Blend sales distribution by sales market** | **Three months ended June 30, 2021** | | |
|---|---|---|---|
| | **Edmonton (US$/bbl)** | **USGC (US$/bbl)** | **TOTAL (US$/bbl)** |
| *(US$ per barrel of blend sales, unless otherwise indicated)* | **Pipeline** | **Pipeline**[3] | |
| WTI - benchmark | $ 66.07 | $ 66.07 | $ 66.07 |
| Differential - WTI:AWB at sales point | (14.70) | (3.86) | (9.87) |
| Asset optimization | — | 0.46 | 0.21 |
| Blend sales price | 51.37 | 62.67 | 56.41 |
| Transportation and storage[1] | (2.14) | (11.15) | (6.17) |
| Transportation and storage from Christina Lake to Edmonton[2] | 2.14 | 2.14 | 2.14 |
| Blend sales price, net of transportation & storage at Edmonton | $ 51.37 | $ 53.66 | $ 52.38 |
| Total blend sales - bbls/d | 71,693 | 57,781 | 129,474 |
| % of total sales | 55 % | 45 % | 100 % |

| | **Edmonton (US$/bbl)** | **USGC (US$/bbl)** | **USGC premium (US$/bbl)** |
|---|---|---|---|
| Average blend sales price by location | $ 51.37 | $ 62.67 | $ 11.30 |
| Transportation and storage[1] | (2.14) | (11.15) | (9.01) |
| Transportation and storage from Christina Lake to Edmonton[2] | 2.14 | 2.14 | — |
| Blend sales price, net of transportation & storage at Edmonton | $ 51.37 | $ 53.66 | $ 2.29 |

| **Blend sales distribution by sales market** | **Three months ended June 30, 2020** | | | |
|---|---|---|---|---|
| | **Edmonton (US$/bbl)** | | **USGC (US$/bbl)** | **TOTAL (US$/bbl)** |
| *(US$ per barrel of blend sales, unless otherwise indicated)* | **Pipeline** | **Rail** | **Pipeline**[3] | |
| WTI - benchmark | $ 27.85 | $ 27.85 | $ 27.85 | $ 27.85 |
| Differential - WTI:AWB at sales point | (17.15) | (26.01) | (5.93) | (13.62) |
| Asset optimization | — | — | 2.56 | 0.89 |
| Blend sales price | 10.70 | 1.84 | 24.48 | 15.12 |
| Transportation and storage[1] | (2.08) | (13.53) | (11.66) | (5.92) |
| Transportation and storage from Christina Lake to Edmonton[2] | 2.08 | 2.08 | 2.08 | 2.08 |
| Blend sales price, net of transportation & storage at Edmonton | $ 10.70 | $ (9.61) | $ 14.90 | $ 11.28 |
| Total blend sales - bbls/d | 61,344 | 4,391 | 35,245 | 100,980 |
| % of total sales | 61 % | 4 % | 35 % | 100 % |

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

(1) *Defined as transportation and storage expenses less transportation revenue, per barrel of blend sales volumes. For reference, total transportation and storage costs per barrel, based on bitumen sales volumes, were C$10.91 per barrel for the three months ended June 30, 2021 compared to C$11.77 per barrel for the three months ended June 30, 2020.*

(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 three months ended June 30, 2021 these activities contributed US$0.46 per barrel to the blend sales price at the USGC (pipeline) compared to US$2.56 per barrel during the same period of 2020. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC (pipeline) during the three months ended June 30, 2021 would be US$10.69 per barrel compared to US$11.15 per barrel. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC (pipeline) during the three months ended June 30, 2020 would be US$9.10 per barrel compared to US$11.66 per barrel.*

(4) *Results are translated at the average foreign exchange rate of 1.2280 for the three months ended June 30, 2021 and 1.3860 for the three months ended June 30, 2020.*

| **Blend sales distribution by sales market** | **Six months ended June 30, 2021** | | |
|---|---|---|---|
| | **Edmonton (US$/bbl)** | **USGC (US$/bbl)** | |
| *(US$ per barrel of blend sales, unless otherwise indicated)* | **Pipeline** | **Pipeline[3]** | **TOTAL (US$/bbl)** |
| WTI - benchmark | $ 61.96 | $ 61.96 | $ 61.96 |
| Differential - WTI:AWB at sales point | (14.98) | (3.20) | (10.12) |
| Asset optimization | — | 1.28 | 0.53 |
| Blend sales price | 46.98 | 60.04 | 52.37 |
| Transportation and storage[1] | (2.08) | (11.92) | (6.15) |
| Transportation and storage from Christina Lake to Edmonton[2] | 2.08 | 2.08 | 2.08 |
| Blend sales price, net of transportation & storage at Edmonton | $ 46.98 | $ 50.20 | $ 48.30 |
| Total blend sales - bbls/d | 75,679 | 53,180 | 128,859 |
| % of total sales | 59 % | 41 % | 100 % |

| | **Edmonton (US$/bbl)** | **USGC (US$/bbl)** | **USGC premium (US$/bbl)** |
|---|---|---|---|
| Average blend sales price by location | $ 46.98 | $ 60.04 | $ 13.06 |
| Transportation and storage[1] | (2.08) | (11.92) | (9.84) |
| Transportation and storage from Christina Lake to Edmonton[2] | 2.08 | 2.08 | — |
| Blend sales price, net of transportation & storage at Edmonton | $ 46.98 | $ 50.20 | $ 3.22 |

| **Blend sales distribution by sales market** | **Six months ended June 30, 2020** | | | | |
|---|---|---|---|---|---|
| | **Edmonton (US$/bbl)** | | **USGC (US$/bbl)** | | |
| *(US$ per barrel of blend sales, unless otherwise indicated)* | **Pipeline** | **Rail** | **Pipeline[3]** | **Rail** | **TOTAL (US$/bbl)** |
| WTI - benchmark | $ 37.01 | $ 37.01 | $ 37.01 | $ 37.01 | $ 37.01 |
| Differential - WTI:AWB at sales point | (19.84) | (15.81) | (6.58) | 12.65 | (15.50) |
| Asset optimization | — | — | 1.80 | — | 0.48 |
| Blend sales price | 17.17 | 21.20 | 32.23 | 49.66 | 21.99 |
| Transportation and storage[1] | (1.93) | (4.90) | (11.34) | (24.73) | (5.02) |
| Transportation and storage from Christina Lake to Edmonton[2] | 1.93 | 1.93 | 1.93 | 1.82 | 1.93 |
| Blend sales price, net of transportation & storage at Edmonton | $ 17.17 | $ 18.23 | $ 22.82 | $ 26.75 | $ 18.90 |
| Total blend sales - bbls/d | 72,150 | 16,129 | 32,258 | 1,143 | 121,680 |
| % of total sales | 59 % | 13 % | 27 % | 1 % | 100 % |

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

(1) *Defined as transportation and storage expenses less transportation revenue, per barrel of blend sales volumes. For reference, total transportation and storage costs per barrel, based on bitumen sales volumes, were C$11.15 per barrel for the six months ended June 30, 2021 compared to C$9.96 per barrel for the six months ended June 30, 2020.*

(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 six months ended June 30, 2021 these activities contributed US$1.28 per barrel to the blend sales price at the USGC (pipeline) compared to US$1.80 per barrel during the same period of 2020. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC (pipeline) during the six months ended June 30, 2021 would be US$10.64 per barrel compared to US$11.92 per barrel. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC (pipeline) during the six months ended June 30, 2020 would be US$9.54 per barrel compared to US$11.34 per barrel.*

(4) *Results are translated at the average foreign exchange rate of 1.2471 for the six months ended June 30, 2021 and 1.3653 for the six months ended June 30, 2020.*

On a transportation adjusted basis, the Corporation's USGC blend sales received a premium over the Edmonton blend sales of US$2.29 per barrel and US$3.22 per barrel for the three and six months ended June 30, 2021. This compares to premiums of US$5.55 per barrel and US$5.59 per barrel at the USGC compared to the Edmonton market during the same periods of 2020. The lower premiums compared to the same periods of 2020 are primarily the result of narrower realized differentials at Edmonton due to improved pipeline egress capacity and increased storage capacity in Alberta.

The Corporation's realized blend sales price at Edmonton was US$51.37 per barrel and US$46.98 per barrel for the three and six months ended June 30, 2021, respectively. This compares to the posted AWB benchmark prices of US$52.96 per barrel and US$48.29 per barrel for same periods. The realized blend sales price at Edmonton was below the benchmark price mainly due to physical commodity risk management contracts that were entered into in December 2020 when expected 2021 differentials were much wider. These sales contracts expired at June 30, 2021.

### Revenue

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

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2021** | **2020** | **2021** | **2020** |
| Sales from: | | | | |
| Production | **$ 813** | $ 181 | **$ 1,508** | $ 650 |
| Purchased product[1] | **187** | 118 | **385** | 297 |
| Petroleum revenue | **$ 1,000** | $ 299 | **$ 1,893** | $ 947 |
| Royalties | **(14)** | — | **(21)** | (6) |
| Petroleum revenue, net of royalties | **$ 986** | $ 299 | **$ 1,872** | $ 941 |
| Power revenue | **$ 21** | $ 6 | **$ 46** | $ 26 |
| Transportation revenue | **2** | 2 | **5** | 5 |
| Other revenue | **$ 23** | $ 8 | **$ 51** | $ 31 |
| Total revenues | **$ 1,009** | $ 307 | **$ 1,923** | $ 972 |

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

During the three and six months ended June 30, 2021, total revenues increased 229% and 98%, respectively, from the same periods of 2020 primarily as a result of the increase in the average blend sales price by $48.31 per barrel and $35.29 per barrel, respectively, which was mostly driven by the increase in WTI prices. The increase in total revenues was also impacted by a 28% and 6% increase in blend sales volumes, respectively.

### Net Earnings (Loss)

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions, except per share amounts)* | **2021** | **2020** | **2021** | **2020** |
| Net earnings (loss) | **$ 68** | $ (80) | **$ 51** | $ (364) |
| Per share, diluted | **$ 0.22** | $ (0.26) | **$ 0.17** | $ (1.21) |

The Corporation recognized net earnings of $68 million and $51 million for the three and six months ended June 30, 2021, respectively, compared to a net loss of $80 million and $364 million during the same periods of 2020, respectively. Increased net earnings was primarily due to stronger global crude oil prices partially offset by commodity price risk management losses as a result of stronger forward commodity prices. Also impacting the net loss during the six months ended June 30, 2020 was the recognition of a $366 million exploration expense.

### Capital Expenditures

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| ($millions) | 2021 | 2020[(1)] | 2021 | 2020[(1)] |
| Sustaining and maintenance | **$ 59** | $ 10 | **$ 124** | $ 50 |
| Phase 2B brownfield expansion | **7** | — | **11** | 14 |
| Field infrastructure, corporate and other | **4** | — | **5** | — |
| Turnaround | **—** | 10 | **—** | 10 |
| eMVAPEX | **—** | 4 | **—** | 6 |
| | **$ 70** | $ 24 | **$ 140** | $ 80 |
| eMVAPEX government grant | **—** | (4) | **—** | (6) |
| | **$ 70** | $ 20 | **$ 140** | $ 74 |

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

The increase in capital spending for the three and six months ended June 30, 2021, compared to the same periods of 2020, reflects the Corporation's decision to reduce capital spending in 2020 due to the unprecedented negative oil price environment experienced in the first half 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. Capital expenditures during the three and six months ended June 30, 2021 primarily consisted of sustaining and maintenance activities.

The Corporation's eMVAPEX pilot has achieved most of its preliminary goals and is in the process of recovering previously injected solvent. The Corporation continues to evaluate the process.

The Phase 2B brownfield expansion was operational in the second quarter of 2021 and will increase steam capacity to enable production increases concurrent with increased investment in additional wells. The total estimated cost of the expansion is approximately $260 million, which is less than the original budget of $275 million.

## 5. OUTLOOK

On December 7, 2020 the Corporation released its original 2021 capital and operating budget. On July 22, 2021, the Corporation revised its 2021 annual guidance. Based on better than expected production performance in the first half of 2021, the Corporation revised its full year 2021 average production from 86,000 – 90,000 bbls/d on December 7, 2020 to 88,000 – 90,000 bbls/d on May 3, 2021 and to 91,000 – 93,000 bbls/d on July 22, 2021.

The Corporation has increased its capital expenditure guidance by $75 million, the majority of which will be funded by proceeds on the sale of non-core industrial lands near Edmonton. The $75 million of additional capital investment represents the majority of the estimated $125 million incremental well capital necessary to allow the Corporation to fully utilize the Christina Lake central plant facility’s oil processing capacity of approximately 100,000 bbls/d, prior to any impact from scheduled maintenance activity or outages.

Non-energy operating costs are now expected to be in the range of $4.40 - $4.60 per barrel. Lower costs in the first half of 2021 were the result of on-going government support and high capitalization rates associated with capital activity. Costs are forecast to increase in the second half of 2021 due to the operation of the completed Phase 2B brownfield expansion project and the timing of planned maintenance activities.

General and administrative expense ("G&A") expense is now targeted to be in the range of $1.65 - $1.75 per barrel.

| Summary of 2021 Guidance | Revised Guidance (July 22, 2021) | Revised Guidance (May 3, 2021) | Original Guidance (December 7, 2020) |
|---|---|---|---|
| Bitumen production - annual average | 91,000 - 93,000 bbls/d | 88,000 - 90,000 bbls/d | 86,000 - 90,000 bbls/d |
| Non-energy operating costs | $4.40 - $4.60 per bbl | $4.60 - $5.00 per bbl | $4.60 - $5.00 per bbl |
| G&A expense | $1.65 - $1.75 per bbl | $1.70 - $1.80 per bbl | $1.70 - $1.80 per bbl |
| Capital expenditures | $335 million | $260 million | $260 million |

MEG is revising downward its expected sales into the USGC via FSP from 50% to approximately 40% of total AWB blend sales. This is lower than previous estimates due to continued higher than forecast apportionment on the Enbridge mainline system. As a result, MEG is revising downward its estimate of full year 2021 total transportation costs from a range of US$6.75 to US$7.25 per barrel of AWB blend sales to a range of US$6.00 to US$6.50 per barrel of AWB blend sales.

## 6. 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:

| | Six months ended June 30 | | 2021 | | 2020 | | | | 2019 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2021 | 2020 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 |
| **Average Benchmark Commodity Prices** | | | | | | | | | | |
| **Crude oil prices** | | | | | | | | | | |
| Brent (US$/bbl) | **65.02** | 42.13 | **68.98** | 61.06 | 45.25 | 43.39 | 33.30 | 50.95 | 62.50 | 61.97 |
| WTI (US$/bbl) | **61.96** | 37.01 | **66.07** | 57.84 | 42.66 | 40.93 | 27.85 | 46.17 | 56.96 | 56.45 |
| Differential – WTI:WCS – Edmonton (US$/bbl) | **(11.98)** | (16.00) | **(11.49)** | (12.47) | (9.30) | (9.09) | (11.47) | (20.53) | (15.83) | (12.24) |
| Differential – WTI:AWB – Edmonton (US$/bbl) | **(13.67)** | (18.11) | **(13.11)** | (14.22) | (10.56) | (10.48) | (13.44) | (22.78) | (18.44) | (14.52) |
| AWB – Edmonton (US$/bbl) | **48.29** | 18.90 | **52.96** | 43.62 | 32.10 | 30.45 | 14.41 | 23.39 | 38.52 | 41.93 |
| Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl) | **(3.22)** | (6.52) | **(3.92)** | (2.52) | (2.83) | (3.20) | (7.29) | (5.74) | (5.25) | (2.50) |
| AWB – U.S. Gulf Coast (US$/bbl) | **58.74** | 30.49 | **62.15** | 55.32 | 39.83 | 37.73 | 20.56 | 40.43 | 51.71 | 53.95 |
| **Condensate prices** | | | | | | | | | | |
| Condensate at Edmonton (C$/bbl) | **77.53** | 46.24 | **81.55** | 73.51 | 55.39 | 50.03 | 30.72 | 61.76 | 70.01 | 68.73 |
| Condensate at Edmonton as % of WTI | **100.3%** | 91.5% | **100.5%** | 100.4% | 99.6% | 91.8% | 79.6% | 99.5% | 93.1% | 92.2% |
| Condensate at Mont Belvieu, Texas (US$/bbl) | **58.59** | 28.35 | **61.18** | 56.00 | 38.52 | 33.52 | 17.43 | 39.27 | 50.08 | 44.34 |
| Condensate at Mont Belvieu, Texas as % of WTI | **94.6%** | 76.6% | **92.6%** | 96.8% | 90.3% | 81.9% | 62.6% | 85.1% | 87.9% | 78.5% |
| **Natural gas prices** | | | | | | | | | | |
| AECO (C$/mcf) | **3.40** | 2.23 | **3.37** | 3.43 | 2.88 | 2.48 | 2.21 | 2.26 | 2.70 | 0.95 |
| **Electric power prices** | | | | | | | | | | |
| Alberta power pool (C$/MWh) | **100.99** | 48.16 | **104.73** | 97.25 | 46.05 | 43.75 | 29.94 | 66.38 | 47.07 | 46.95 |
| **Foreign exchange rates** | | | | | | | | | | |
| C$ equivalent of 1 US$ – average | **1.2471** | 1.3653 | **1.2280** | 1.2663 | 1.3031 | 1.3316 | 1.3860 | 1.3445 | 1.3201 | 1.3207 |
| C$ equivalent of 1 US$ – period end | **1.2405** | 1.3616 | **1.2405** | 1.2572 | 1.2755 | 1.3324 | 1.3616 | 1.4120 | 1.2965 | 1.3244 |

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 crude oil demand. At the same time, overall global crude oil supply increased as efforts between the Organization of Petroleum Exporting Countries ("OPEC") and non-OPEC members to manage global crude oil production levels broke down and each party increased their daily crude production. 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. However, during the second quarter of 2020, the agreement between OPEC and a group of 10 non-OPEC members (collectively, “OPEC+”) to cut crude oil output, and several other countries announcing similar production cuts, decreased the global crude oil supply. At the same time, governments began to ease off on some of the measures taken to contain COVID-19 increasing demand for crude oil, which helped increase global crude oil prices during the second half of 2020 and thus far in 2021. Improving vaccination rates are expected to continue to influence government restrictions impacting demand for crude oil. Price volatility remains largely due to market sensitivity to COVID-19 related news including vaccine breakthroughs and rollouts, the resurgence of COVID-19 cases and developing variants of concern as well as OPEC+ related news.

### 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.

### Condensate Prices

In order to facilitate pipeline transportation of bitumen, the Corporation uses condensate as diluent for blending with the Corporation’s bitumen. The price of condensate generally correlates with the price of WTI. 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. Condensate pricing was impacted by market conditions precipitated by COVID-19 when condensate pricing fell sharply in the second quarter of 2020 which was in line with reduced thermal oil production and lower demand for diluent. During the second half of 2020, condensate pricing steadily increased as pricing came back in line with WTI. Condensate pricing has subsequently strengthened beyond levels seen prior to COVID-19 as supply has not responded as quickly as demand in both the Edmonton area and USGC. Refer to bitumen realization within the "CASH OPERATING NETBACK" section of this MD&A for further details.

### Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, used as fuel to generate steam for the thermal production process and to create steam and electricity from the Corporation's cogeneration facilities. The AECO natural gas price increased during the three and six months ended June 30, 2021 compared to the same periods of 2020 due to market uncertainty surrounding possible gas supply constraints in 2021, coupled with extreme weather conditions in the first quarter of 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 increased during the three and six months ended June 30, 2021 compared to the same periods of 2020 primarily as a result of extreme weather conditions in February and June 2021.

## 7. OTHER OPERATING RESULTS

### General and Administrative

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions, except as indicated)* | **2021** | **2020** | **2021** | **2020** |
| General and administrative expense | **$ 13** | $ 9 | **$ 27** | $ 25 |
| General and administrative expense per barrel of production | **$ 1.56** | $ 1.29 | **$ 1.66** | $ 1.66 |

G&A expense increased 46% and 9% during the three and six months ended June 30, 2021 compared to the same periods of 2020. Throughout 2020, the Corporation drove efficiencies into its cost structure through various efforts 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 which offset G&A costs by approximately $3 million.

### Depletion and Depreciation

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions, except as indicated)* | **2021** | **2020** | **2021** | **2020** |
| Depletion and depreciation expense | **$ 108** | $ 93 | **$ 216** | $ 217 |
| Depletion and depreciation expense per barrel of production | **$ 12.99** | $ 13.55 | **$ 13.07** | $ 14.25 |

Depletion and depreciation expense was $12.99 per barrel and $13.07 per barrel for the three and six months ended June 30, 2021, respectively, compared to $13.55 per barrel and $14.25 per barrel for the same periods of 2020, respectively. Depletion and depreciation expense per barrel has decreased during the three and six months ended June 30, 2021, compared to the same periods in 2020, primarily due to the increase in production.

### Exploration Expense

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2021** | **2020** | **2021** | **2020** |
| Exploration expense | **$ —** | $ — | **$ —** | **$ 366** |

Exploration expense is recognized when facts and circumstances suggest that the carrying amount exceeds the recoverable amount and the Corporation decides to discontinue exploration and evaluation activities which are pending the determination of proved or probable reserves. During the three and six months ended June 30, 2021 there was no exploration expense recognized. During the first quarter of 2020, the Corporation discontinued exploration and evaluation activities in certain non-core growth properties as it narrowed the development focus to core assets at Christina Lake. The associated land lease and evaluation costs totaling $366 million were charged to exploration expense.

### Commodity Risk Management Gain (Loss)

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

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2021** | **2020** | **2021** | **2020** |
| **Realized:** | | | | |
| Crude oil contracts(1) | **$ (94)** | $ 226 | **$ (175)** | $ 335 |
| Condensate contracts(2) | **6** | (11) | **17** | (14) |
| Natural gas contracts(3) | **1** | — | **2** | — |
| **Realized commodity risk management gain (loss)** | **$ (87)** | $ 215 | **$ (156)** | $ 321 |
| **Unrealized:** | | | | |
| Crude oil contracts(1) | **$ (21)** | $ (323) | **$ (107)** | $ 117 |
| Condensate contracts(2) | **(14)** | 56 | **(19)** | 44 |
| Natural gas contracts(3) | **8** | — | **11** | — |
| **Unrealized commodity risk management gain (loss)** | **$ (27)** | $ (267) | **$ (115)** | $ 161 |
| **Commodity risk management gain (loss)** | **$ (114)** | $ (52) | **$ (271)** | $ 482 |

*(1) Includes WTI fixed price contracts, WTI enhanced fixed price contracts with sold put options and WTI:WCS fixed differential contracts.*

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

*(3) Relates to contracts which fix the AECO price on natural gas purchases.*

For the three and six months ended June 30, 2021, the Corporation recognized a $114 million net loss and a $271 million net loss, respectively, from commodity risk management primarily due to losses on both settlement and the change in mark-to-market value of WTI fixed price contracts and WTI enhanced fixed price contracts with sold put options, as both actual and forward WTI prices were stronger and actual WTI:WCS differentials were narrower compared to contracted prices during these periods.

During the three months ended June 30, 2020, a $52 million commodity risk management loss was recognized which reflected a modest recovery in WTI prices through the second quarter of 2020. During the six months ended June 30, 2020, a commodity risk management gain of $482 million was recognized which reflected the significant decline in WTI prices due to the demand shock on global markets driven by COVID-19.

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

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **(US$/bbl)** | **2021** | **2020** | **2021** | **2020** |
| **WTI fixed price contracts[1][2]:** | | | | |
| Average fixed price | **$ 46.22** | $ 56.75 | **$ 46.92** | $ 57.74 |
| Average settlement price | **66.06** | 27.85 | **60.96** | 37.01 |
| Gain (loss) on WTI fixed price contracts | **$ (19.84)** | $ 28.90 | **$ (14.04)** | $ 20.73 |
| **WTI:WCS fixed differential contracts:** | | | | |
| Average fixed differential | **$ (12.26)** | $ (18.67) | **$ (12.46)** | $ (19.85) |
| Average settlement differential | **(11.40)** | (11.47) | **(11.41)** | (16.00) |
| Gain (loss) on WTI:WCS fixed differential contracts | **$ (0.86)** | $ (7.20) | **$ (1.05)** | $ (3.85) |
| **Condensate purchase contracts:** | | | | |
| Average fixed differential[3] | **$ (9.74)** | $ (5.81) | **$ (10.03)** | $ (5.59) |
| Average settlement differential | **(5.08)** | (10.47) | **(3.55)** | (8.69) |
| Gain (loss) on condensate purchase contracts | **$ 4.66** | $ (4.66) | **$ 6.48** | $ (3.10) |
| **Natural gas purchase contracts:** | | | | |
| Average fixed price | **$ 2.60** | $ — | **$ 2.61** | $ — |
| Average settlement price | **2.93** | — | **2.94** | — |
| Gain (loss) on natural gas purchase contracts | **$ 0.33** | $ — | **$ 0.33** | $ — |

(1) *Includes enhanced fixed price with sold put option contracts.*
(2) *Incremental to these WTI fixed price contracts, the Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months, the gains and losses on which are not reflected in this table.*
(3) *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.*

### Stock-based Compensation

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2021** | **2020** | **2021** | **2020** |
| Cash-settled expense (recovery) | **$ 17** | $ 9 | **$ 36** | $ (9) |
| Equity-settled expense | **5** | 2 | **7** | 7 |
| Equity price risk management (gain) loss[1] | **$ (18)** | $ (19) | **$ (37)** | $ (20) |
| Stock-based compensation | **$ 4** | $ (8) | **$ 6** | $ (22) |

(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 cash-settled expense recognized during the three and six months ended June 30, 2021 was due to the increase in the Corporation's share price. The Corporation's common share price increased to $8.97 per share as at June 30, 2021, from its value of $6.53 per share as at March 31, 2021 and $4.45 per share as at December 31, 2020.

The cash-settled expense during the three months ended June 30, 2020 was due to the increase in the Corporation's share price to $3.77 per share as at June 30, 2020 from its value of $1.67 per share as at March 31, 2020. Conversely, the cash-settled recovery during the six months ended June 30, 2020 was primarily due to the decrease in the Corporation's share price to $3.77 per share as at June 30, 2020 from its value of $7.39 per share as at December 31, 2019.

Equity-settled stock based compensation expense increased for the three months ended June 30, 2021, compared to the same period of 2020, primarily due to an increase in the value of awards granted which were temporarily reduced in 2020 in response to the challenging low oil price environment.

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 three and six months ended June 30, 2021, an equity price risk management gain of $18 million and $37 million, respectively, was recognized on the increase in share price during the periods.

### Foreign Exchange Gain (Loss), Net

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2021** | **2020** | **2021** | **2020** |
| Unrealized foreign exchange gain (loss) on: | | | | |
| Long-term debt | **$ 38** | $ 116 | **$ 86** | $ (162) |
| US$ denominated cash and cash equivalents | **3** | (2) | **(2)** | 9 |
| Unrealized net gain (loss) on foreign exchange | **41** | 114 | **84** | (153) |
| Realized gain (loss) on foreign exchange | **—** | 2 | **—** | (1) |
| Foreign exchange gain (loss), net | **$ 41** | $ 116 | **$ 84** | $ (154) |

| | | | | |
|---|---|---|---|---|
| C$ equivalent of 1 US$ | | | | |
| Beginning of period | **1.2572** | 1.4120 | **1.2755** | 1.2965 |
| End of period | **1.2405** | 1.3616 | **1.2405** | 1.3616 |

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.

During the three and six months ended June 30, 2021, the Canadian dollar strengthened relative to the U.S. dollar by 1% and 3%, respectively, resulting in unrealized foreign exchange gains of $41 million and $84 million, respectively.

During the three months ended June 30, 2020, the Canadian dollar strengthened by 4%, resulting in an unrealized foreign exchange gain of $114 million. During the six months ended June 30, 2020, the Canadian dollar weakened relative to the U.S. dollar by 5%, resulting in an unrealized foreign exchange loss of $153 million.

### Net Finance Expense

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2021** | **2020** | **2021** | **2020** |
| Interest expense on long-term debt | **$ 53** | $ 60 | **$ 111** | $ 124 |
| Interest expense on lease liabilities | **7** | 7 | **13** | 13 |
| Interest income | **—** | — | **—** | (2) |
| Net interest expense | **60** | 67 | **124** | 135 |
| Debt extinguishment expense | **5** | — | **5** | — |
| Accretion on provisions | **2** | 2 | **4** | 4 |
| Net finance expense | **$ 67** | $ 69 | **$ 133** | $ 139 |

| | | | | |
|---|---|---|---|---|
| Average effective interest rate | **6.7%** | 7.0% | **6.7%** | 6.9% |

Interest expense on long-term debt decreased during the three and six months ended June 30, 2021 compared to the same periods of 2020 mainly as a result of the strengthening Canadian dollar as all of the Corporation's long-term debt is denominated in US dollars. Also contributing to the decrease was the refinancing of US$600 million of senior unsecured notes on February 2, 2021 at a rate of 5.875% compared to the previous rate of 7.0%.

For the three and six months ended June 30, 2021, debt extinguishment expense was recognized in association with the July 22, 2021 announced debt redemption and included a cumulative debt redemption premium of $4 million and associated unamortized deferred debt issue costs of $1 million. Refer to Note 6 of the interim consolidated financial statements for further details.

### Income Tax

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2021** | **2020** | **2021** | **2020** |
| Current income tax expense (recovery) | **$ (2)** | $ (1) | **$ (2)** | $ (1) |
| Deferred income tax expense (recovery) | **17** | (61) | **(2)** | (63) |
| Income tax expense (recovery) | **$ 15** | $ (62) | **$ (4)** | $ (64) |
| Effective tax rate | **18 %** | 43 % | **(8)%** | 15 % |

For the three and six months ended June 30, 2021, the Corporation recognized a $12 million deferred tax expense associated with the tax treatment of a prior year investment in pipeline access. The Corporation disputes the current Canada Revenue Agency assessment and is considering its alternatives.

As at June 30, 2021, the Corporation had approximately $7.4 billion of available Canadian tax pools and recognized a deferred income tax asset of $384 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

The effective tax rates differ from the Canadian statutory rate of 23% primarily due to the tax effect of realized and unrealized foreign exchange gains and losses on the Corporation's debt which is denominated in U.S. dollars.

## 8. LIQUIDITY AND CAPITAL RESOURCES

| *($millions)* | **June 30, 2021** | **December 31, 2020** |
|---|---|---|
| **Second Lien:** | | |
| 6.5% senior secured second lien notes (June 30, 2021 - US$496 million; December 31, 2020 - US$496 million; due 2025) | **$ 615** | $ 633 |
| **Unsecured:** | | |
| 7.125% senior unsecured notes (June 30, 2021 - US$1.2 billion; December 31, 2020 - US$1.2 billion; due 2027) | **1,489** | 1,531 |
| 5.875% senior unsecured notes (June 30, 2021 - US$600 million; December 31, 2020 - US$nil; due 2029) | **744** | — |
| 7.0% senior unsecured notes (June 30, 2021 - US$nil; December 31, 2020 - US$600 million; due 2024) | **—** | 765 |
| Debt redemption premium | **4** | 9 |
| Unamortized deferred debt discount and debt issue costs | **(32)** | (26) |
| Long-term debt | **2,820** | 2,912 |
| Cash and cash equivalents | **(159)** | (114) |
| Net debt[1] | **$ 2,661** | $ 2,798 |

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

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 7.0% senior unsecured notes due March 2024 at a redemption price of 101.167% and to pay fees and expenses related to the offering.

The Corporation's cash and cash equivalents balance was $159 million as at June 30, 2021 compared to $114 million as at December 31, 2020. Refer to the "Cash Flow Summary" section for further details.

Subsequent to June 30, 2021, on July 22, 2021, the Corporation announced that it had issued a notice to redeem US$100 million (approximately C$125 million) of the Corporation's 6.50% senior secured second lien notes due January 2025 at a redemption price of 103.25%, plus accrued and unpaid interest to, but not including, the redemption date. The redemption is expected to be completed on or about August 23, 2021.

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.

Meeting current and future obligations while navigating the uncertainty associated with commodity market volatility continues to be supported by the Corporation's financial framework, including a commodity risk management program securing cash flow through 2021, and credit risk management policies minimizing credit exposure on sales to primarily investment grade customers in the energy industry. The Corporation's earliest maturing long-term debt is three and a half 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 June 30, 2021, the Corporation had $785 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $112 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 three months ended March 31, 2020 that remains outstanding. Letters of credit issued under the revolving credit facility are not included in first lien net debt for purposes of calculating the first lien net leverage ratio.

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

### Cash Flow Summary

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2021** | **2020** | **2021** | **2020** |
| Net cash provided by (used in): | | | | |
| Operating activities | **$ 180** | $ 117 | **$ 192** | $ 216 |
| Investing activities | **(73)** | (50) | **(122)** | (109) |
| Financing activities | **(5)** | (7) | **(22)** | (203) |
| Effect of exchange rate changes on cash and cash equivalents held in foreign currency | **3** | (2) | **(3)** | 10 |
| Change in cash and cash equivalents | **$ 105** | $ 58 | **$ 45** | $ (86) |

### Cash Flow – Operating Activities

Net cash provided by operating activities for the three months ended June 30, 2021 increased compared to the same period of 2020, primarily due to higher benchmark crude oil prices.

Net cash provided by operating activities for the six months ended June 30, 2021 decreased compared to the same period of 2020, primarily due to a change in working capital requirements. Before non-cash working capital, funds flow from operating activities increased mainly due to higher benchmark crude oil prices.

### Cash Flow – Investing Activities

Net cash used in investing activities increased during the three and six months ended June 30, 2021 compared to the same periods of 2020 reflecting increased capital spending over these periods.

### Cash Flow – Financing Activities

Net cash used in financing activities for the three months ended June 30, 2021 decreased compared to the same period of 2020, primarily due to the receipt of proceeds from shares issued during the three months ended June 30, 2021.

Net cash used in financing activities for the six months ended June 30, 2021 decreased compared to the same period of 2020, primarily due to larger debt repayment and associated higher debt redemption and refinancing costs incurred during the six months ended June 30, 2020.

## 9. 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 June 30, 2021:

| **As at June 30, 2021** | | | |
|---|---|---|---|
| **Crude Oil Sales Contracts**[1] | **Volumes (bbls/d)**[2] | **Term** | **Average Price (US$/bbl)**[2] |
| WTI:WCS Fixed Differential | 10,000 | Jul 1, 2021 - Sep 30, 2021 | $(11.05) |
| **Enhanced Fixed Price with Sold Put Option** | | | |
| WTI Fixed Price/Sold Put Option Strike Price | 29,000 | Jul 1, 2021 - Dec 31, 2021 | $46.18/$38.79 |
| **Condensate Purchase Contracts** | | | |
| WTI:Mont Belvieu Fixed Differential | 10,950 | Jul 1, 2021 - Dec 31, 2021 | $(10.37) |
| WTI:Mont Belvieu Fixed Differential | 200 | Jan 1, 2022 - Dec 31, 2022 | $(11.30) |
| **Natural Gas Purchase Contracts** | **Volumes (GJ/d)**[2] | **Term** | **Average Price (C$/GJ)**[2] |
| AECO Fixed Price | 37,500 | Jul 1, 2021 - Dec 31, 2021 | $2.60 |
| AECO Fixed Price | 5,000 | Jan 1, 2022 - Dec 31, 2023 | $2.50 |

*(1) Incremental to these crude oil sales contracts, the Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months.*

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

Except for contracts to fix the spread between July and August 2021 WTI prices, the Corporation did not enter into financial commodity risk management contracts between June 30, 2021 and July 22, 2021.

The following table summarizes the sensitivity of cash operating netback, adjusted funds flow and earnings (loss) before income tax of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place as at June 30, 2021:

| Commodity | Sensitivity Range | Increase | Decrease |
|---|---|---|---|
| Crude oil commodity price | ± US$5.00 per bbl applied to WTI contracts | **$ (33)** | **$ 32** |
| Crude oil differential price | ± US$5.00 per bbl applied to WTI:WCS differential contracts | **$ 6** | **$ (6)** |
| Condensate purchase price | ± 5% in condensate price as a percentage of WTI | **$ 9** | **$ (9)** |
| Natural gas purchase price | ± C$0.50 per GJ applied to natural gas contracts | **$ 5** | **$ (5)** |

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 June 30, 2021:

| **Condensate Purchase Contracts** | **Volumes (bbls/d)**[1] | **Term** | **Average Price (US$/bbl)**[1] |
|---|---|---|---|
| WTI:Condensate Fixed Differential | 3,078 | Jul 1, 2021 - Dec 31, 2021 | $(1.80) |
| **Natural Gas Purchase Contracts** | **Volumes (GJ/d)**[1] | **Term** | **Average Price (C$/GJ)**[1] |
| AECO Fixed Price | 5,000 | Jul 1, 2021 - Dec 31, 2021 | $2.70 |
| **Power Sales Contracts** | **Quantity (MW)**[1] | **Term** | **Average Price (C$/MWh)**[1] |
| Fixed Price | 35 | Jul 1, 2021 - Dec 31, 2021 | $62.75 |

*(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 and the revaluation is recognized in stock-based compensation expense. 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 cash-settled RSUs and PSUs vesting between 2021 and 2023.

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2021** | **2020** | **2021** | **2020** |
| Unrealized equity price risk management (gain) loss | **$ (18)** | $ (19) | **$ (29)** | $ (20) |
| Realized equity price risk management (gain) loss | **—** | — | **(8)** | — |
| Equity price risk management (gain) loss | **$ (18)** | $ (19) | **$ (37)** | $ (20) |

## 10. SHARES OUTSTANDING

As at June 30, 2021, the Corporation had the following share capital instruments outstanding or exercisable:

| *(millions)* | **Units** |
|---|---|
| Common shares | **306.7** |
| Convertible securities | |
| Stock options(1) | **2.7** |
| Equity-settled RSUs and PSUs | **6.4** |

*(1) 2.5 million stock options were exercisable as at June 30, 2021.*

As at July 21, 2021, the Corporation had 306.7 million common shares, 2.7 million stock options and 6.4 million equity-settled RSUs and equity-settled PSUs outstanding, and 2.5 million stock options exercisable.

## 11. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

### Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations as at June 30, 2021. 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) | $ 197 | $ 399 | $ 440 | $ 435 | $ 411 | $ 5,657 | $ 7,539 |
| Diluent purchases | 100 | 20 | 17 | — | — | — | 137 |
| Other operating commitments | 11 | 16 | 16 | 13 | 12 | 36 | 104 |
| Variable office lease costs | 2 | 4 | 4 | 4 | 5 | 27 | 46 |
| Capital commitments | 35 | — | — | — | — | — | 35 |
| **Total Commitments** | 345 | 439 | 477 | 452 | 428 | 5,720 | 7,861 |
| **Other Obligations:** | | | | | | | |
| Lease obligations | 40 | 46 | 40 | 39 | 30 | 499 | 694 |
| Long-term debt(2) | — | — | — | — | 615 | 2,233 | 2,848 |
| Interest on long-term debt(2) | 94 | 190 | 190 | 190 | 153 | 256 | 1,073 |
| Decommissioning obligation(3) | 2 | 4 | 5 | 4 | 4 | 775 | 794 |
| **Obligations** | **$ 481** | **$ 679** | **$ 712** | **$ 685** | **$ 1,230** | **$ 9,483** | **$ 13,270** |

(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 June 30, 2021.*

(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.

## 12. 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.

## 13. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

## 14. 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.

## 15. 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.

## 16. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

## 17. 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 |

## 18. 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: the Corporation's 2021 guidance, including full year 2021 production, non-energy operating costs, general and administrative costs, capital expenditures and total transportation costs; the Corporation's intention to redeem US$100 million of the Corporation's 6.50% second lien notes due January 2025; the Corporation's actions taken to ensure the health and safety of its personnel and business partners and the safe and reliable operation of the Christina Lake facility; the Corporation's climate-related goals, including achieving net zero carbon emissions by 2050; the increased steam capacity of the Phase 2B brownfield expansion to enable production increases concurrent with increased investment in additional wells; the expectation that $125 million incremental well capital will allow the Corporation to fully utilize the Christina Lake central plant's oil processing capacity of approximately 100,000 bbs/d; expected sales into the USGC via FSP; future production, revenues, expenses, cash flow, operating costs, steam-oil ratios, pricing differentials, reliability, profitability and capital expenditures; actions taken to respond to the impact of reduced use of fossil fuels and addressing risks arising out of climate change concerns; commodity prices; estimates of reserves and resources; anticipated sources of funding for operations and capital expenditures; the Corporation's liquidity and ability to meet its current and future obligations; and the Corporation's hedge book. 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; 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.

## 19. 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.

## 20. QUARTERLY SUMMARIES

| | 2021 | | 2020 | | | | 2019 | |
|---|---|---|---|---|---|---|---|---|
| **Unaudited** | **Q2** | **Q1** | **Q4** | **Q3** | **Q2** | **Q1** | **Q4** | **Q3** |
| **FINANCIAL** *($millions unless specified)* | | | | | | | | |
| Net earnings (loss) | **68** | (17) | 16 | (9) | (80) | (284) | 26 | 24 |
| Per share, diluted | **0.22** | (0.06) | 0.05 | (0.03) | (0.26) | (0.95) | 0.09 | 0.08 |
| Adjusted funds flow | **166** | 127 | 84 | 26 | 89 | 76 | 156 | 191 |
| Per share, diluted | **0.53** | 0.41 | 0.27 | 0.09 | 0.29 | 0.25 | 0.51 | 0.63 |
| Capital expenditures | **70** | 70 | 40 | 36 | 20 | 54 | 72 | 40 |
| Cash and cash equivalents | **159** | 54 | 114 | 49 | 120 | 62 | 206 | 154 |
| Working capital | **127** | 8 | 55 | 131 | 173 | 371 | 123 | 204 |
| Long-term debt | **2,820** | 2,852 | 2,912 | 3,030 | 3,096 | 3,212 | 3,123 | 3,257 |
| Shareholders' equity | **3,564** | 3,491 | 3,506 | 3,495 | 3,507 | 3,593 | 3,853 | 3,828 |
| **BUSINESS ENVIRONMENT** | | | | | | | | |
| **Average Benchmark Commodity Prices:** | | | | | | | | |
| WTI (US$/bbl) | **66.07** | 57.84 | 42.66 | 40.93 | 27.85 | 46.17 | 56.96 | 56.45 |
| Differential – WTI:WCS – Edmonton (US$/bbl) | **(11.49)** | (12.47) | (9.30) | (9.09) | (11.47) | (20.53) | (15.83) | (12.24) |
| Differential – WTI:AWB – Edmonton (US$/bbl) | **(13.11)** | (14.22) | (10.56) | (10.48) | (13.44) | (22.78) | (18.44) | (14.52) |
| AWB – Edmonton (US$/bbl) | **52.96** | 43.62 | 32.10 | 30.45 | 14.41 | 23.39 | 38.52 | 41.93 |
| Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl) | **(3.92)** | (2.52) | (2.83) | (3.20) | (7.29) | (5.74) | (5.25) | (2.50) |
| AWB – U.S. Gulf Coast (US$/bbl) | **62.15** | 55.32 | 39.83 | 37.73 | 20.56 | 40.43 | 51.71 | 53.95 |
| C$ equivalent of 1US$ – average | **1.2280** | 1.2663 | 1.3031 | 1.3316 | 1.3860 | 1.3445 | 1.3201 | 1.3207 |
| Natural gas – AECO ($/mcf) | **3.37** | 3.43 | 2.88 | 2.48 | 2.21 | 2.26 | 2.70 | 0.95 |
| **OPERATIONAL** **($/bbl unless specified)** | | | | | | | | |
| Blend sales, net of purchased product – bbls/d | **129,474** | 128,236 | 136,623 | 93,479 | 100,980 | 142,380 | 134,932 | 132,455 |
| Diluent usage – bbls/d | **(39,494)** | (40,938) | (40,892) | (25,910) | (30,583) | (45,166) | (40,585) | (37,463) |
| Bitumen sales – bbls/d | **89,980** | 87,298 | 95,731 | 67,569 | 70,397 | 97,214 | 94,347 | 94,992 |
| Bitumen production – bbls/d | **91,803** | 90,842 | 91,030 | 71,516 | 75,687 | 91,557 | 94,566 | 93,278 |
| Steam-oil ratio (SOR) | **2.39** | 2.37 | 2.31 | 2.36 | 2.32 | 2.31 | 2.27 | 2.26 |
| Blend sales | **69.27** | 61.28 | 45.75 | 45.44 | 20.96 | 36.46 | 56.55 | 60.26 |
| Cost of diluent | **(9.18)** | (8.94) | (7.11) | (5.76) | (10.78) | (17.01) | (9.69) | (6.89) |
| Bitumen realization | **60.09** | 52.34 | 38.64 | 39.68 | 10.18 | 19.45 | 46.86 | 53.37 |
| Transportation and storage – net | **(10.91)** | (11.41) | (14.11) | (18.55) | (11.77) | (8.63) | (10.75) | (10.57) |
| Third-party curtailment credits | **—** | — | 0.03 | — | — | 0.18 | (0.21) | (0.37) |
| Royalties | **(1.71)** | (0.85) | (0.23) | (0.21) | (0.05) | (0.63) | (1.18) | (1.54) |
| Non-energy operating costs | **(3.84)** | (4.05) | (4.70) | (3.96) | (4.09) | (4.57) | (4.49) | (4.22) |
| Energy operating costs | **(4.27)** | (4.34) | (3.73) | (3.17) | (3.00) | (3.15) | (2.95) | (1.51) |
| Power revenue | **2.57** | 3.14 | 1.45 | 1.08 | 0.95 | 2.21 | 1.57 | 1.43 |
| Realized gain (loss) on commodity risk management | **(10.63)** | (8.80) | 1.31 | 1.71 | 33.62 | 11.97 | (0.52) | (4.15) |
| Cash operating netback | **31.30** | 26.03 | 18.66 | 16.58 | 25.84 | 16.83 | 28.33 | 32.44 |
| Power sales price (C$/MWh) | **88.40** | 93.27 | 46.34 | 39.03 | 28.34 | 69.39 | 49.61 | 50.30 |
| Power sales (MW/h) | **113** | 128 | 125 | 78 | 98 | 129 | 124 | 112 |
| Average cost of diluent ($/bbl of diluent) | **90.18** | 80.34 | 62.37 | 60.48 | 45.76 | 73.09 | 79.07 | 77.71 |
| Average cost of diluent as a % of WTI | **111 %** | 110 % | 112 % | 111 % | 119 % | 118 % | 105 % | 104 % |
| Depletion and depreciation rate per bbl of production | **12.99** | 13.15 | 12.64 | 13.33 | 13.55 | 14.83 | 13.18 | 13.43 |
| General and administrative expense per bbl of production | **1.56** | 1.77 | 1.65 | 1.50 | 1.29 | 1.96 | 2.25 | 1.66 |
| **COMMON SHARES** | | | | | | | | |
| Shares outstanding, end of period (000) | **306,716** | 303,137 | 302,681 | 302,657 | 302,645 | 299,547 | 299,508 | 299,288 |
| Common share price ($) - close (end of period) | **8.97** | 6.53 | 4.45 | 2.77 | 3.77 | 1.67 | 7.39 | 5.80 |

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$66.07/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 first half of 2021, 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 and 2021;
- 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.

## 21. ANNUAL SUMMARIES

| | 2020 | 2019 | 2018[1] | 2017[1] | 2016[1] | 2015[1] | 2014[1] |
|---|---|---|---|---|---|---|---|
| **FINANCIAL** *($millions unless specified)* | | | | | | | |
| Net earnings (loss) | (357) | (62) | (119) | 166 | (429) | (1,170) | (106) |
| Per share, diluted | (1.18) | (0.21) | (0.40) | 0.57 | (1.90) | (5.21) | (0.47) |
| Adjusted funds flow | 275 | 724 | 175 | 371 | (63) | 49 | 790 |
| Per share, diluted | 0.90 | 2.41 | 0.58 | 1.28 | (0.28) | 0.22 | 3.51 |
| Capital expenditures | 149 | 198 | 622 | 502 | 140 | 314 | 1,314 |
| Cash and cash equivalents | 114 | 206 | 318 | 464 | 156 | 408 | 656 |
| Working capital | 55 | 123 | 290 | 313 | 96 | 363 | 526 |
| Long-term debt | 2,912 | 3,123 | 3,740 | 4,668 | 5,053 | 5,190 | 4,350 |
| Shareholders' equity | 3,506 | 3,853 | 3,886 | 3,964 | 3,287 | 3,678 | 4,768 |
| **BUSINESS ENVIRONMENT** | | | | | | | |
| **Average Benchmark Commodity Prices:** | | | | | | | |
| WTI (US$/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) |
| Non-energy operating costs | (4.38) | (4.61) | (4.62) | (4.62) | (5.62) | (6.54) | (8.02) |
| Energy operating costs | (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.*

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

| As at | Note | June 30, 2021 | December 31, 2020 |
|---|---|---|---|
| **Assets** | | | |
| Current assets | | | |
| Cash and cash equivalents | 16 | **$ 159** | $ 114 |
| Trade receivables and other | | **452** | 281 |
| Inventories | | **136** | 96 |
| Risk management | 18 | **25** | 6 |
| | | **772** | 497 |
| Non-current assets | | | |
| Property, plant and equipment | 3 | **5,893** | 5,993 |
| Exploration and evaluation assets | 4 | **126** | 125 |
| Other assets | 5 | **195** | 206 |
| Risk management | 18 | **31** | 21 |
| Deferred income tax asset | | **384** | 382 |
| **Total assets** | | **$ 7,401** | $ 7,224 |
| **Liabilities** | | | |
| Current liabilities | | | |
| Accounts payable and accrued liabilities | | **$ 375** | $ 279 |
| Interest payable | | **82** | 78 |
| Current portion of provisions and other liabilities | 7 | **44** | 56 |
| Risk management | 18 | **144** | 29 |
| | | **645** | 442 |
| Non-current liabilities | | | |
| Long-term debt | 6 | **2,820** | 2,912 |
| Provisions and other liabilities | 7 | **372** | 364 |
| Total liabilities | | **3,837** | 3,718 |
| **Shareholders' equity** | | | |
| Share capital | 8 | **5,485** | 5,460 |
| Contributed surplus | | **164** | 177 |
| Deficit | | **(2,107)** | (2,158) |
| Accumulated other comprehensive income | | **22** | 27 |
| Total shareholders' equity | | **3,564** | 3,506 |
| **Total liabilities and shareholders' equity** | | **$ 7,401** | $ 7,224 |

*Commitments and contingencies (Note 20)*

*Subsequent event (Note 21)*

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

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

| | | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|---|
| | **Note** | **2021** | **2020** | **2021** | **2020** |
| **Revenues** | | | | | |
| Petroleum revenue, net of royalties | 10 | **$ 986** | $ 299 | **$ 1,872** | $ 941 |
| Other revenue | 10 | **23** | 8 | **51** | 31 |
| Total revenues | | **1,009** | 307 | **1,923** | 972 |
| **Expenses** | | | | | |
| Diluent and transportation | 11 | **415** | 205 | **804** | 585 |
| Operating expenses | | **67** | 46 | **133** | 114 |
| Inventory impairment | 5 | **(1)** | (29) | **5** | — |
| Purchased product | | **184** | 106 | **369** | 282 |
| Curtailment | | **—** | — | **—** | (2) |
| Depletion and depreciation | 3, 5 | **108** | 93 | **216** | 217 |
| Exploration expense | 4 | **—** | — | **—** | 366 |
| General and administrative | | **13** | 9 | **27** | 25 |
| Stock-based compensation | 9 | **4** | (8) | **6** | (22) |
| Net finance expense | 13 | **67** | 69 | **133** | 139 |
| Other expenses | 14 | **—** | 22 | **—** | 30 |
| Other income | | **(4)** | — | **(4)** | (6) |
| Commodity risk management (gain) loss, net | 18 | **114** | 52 | **271** | (482) |
| Foreign exchange (gain) loss, net | 12 | **(41)** | (116) | **(84)** | 154 |
| Earnings (loss) before income taxes | | **83** | (142) | **47** | (428) |
| Income tax expense (recovery) | 15 | **15** | (62) | **(4)** | (64) |
| Net earnings (loss) | | **68** | (80) | **51** | (364) |
| Other comprehensive income (loss), net of tax | | | | | |
| Items that may be reclassified to profit or loss: | | | | | |
| Foreign currency translation adjustment | | **(2)** | (8) | **(5)** | 10 |
| Comprehensive income (loss) | | **$ 66** | $ (88) | **$ 46** | $ (354) |
| | | | | | |
| Net earnings (loss) per common share | | | | | |
| Basic | 17 | **$ 0.22** | $ (0.26) | **$ 0.17** | $ (1.21) |
| Diluted | 17 | **$ 0.22** | $ (0.26) | **$ 0.17** | $ (1.21) |

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

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

| | Share Capital | Contributed Surplus | Deficit | Accumulated Other Comprehensive Income | Total Shareholders' Equity |
|---|---|---|---|---|---|
| Balance as at December 31, 2020 | **$ 5,460** | **$ 177** | **$ (2,158)** | **$ 27** | **$ 3,506** |
| Stock-based compensation | **—** | **8** | **—** | **—** | **8** |
| Stock options exercised | **6** | **(2)** | **—** | **—** | **4** |
| RSU vested and released | **19** | **(19)** | **—** | **—** | **—** |
| Comprehensive income (loss) | **—** | **—** | **51** | **(5)** | **46** |
| **Balance as at June 30, 2021** | **$ 5,485** | **$ 164** | **$ (2,107)** | **$ 22** | **$ 3,564** |
| | | | | | |
| Balance as at December 31, 2019 | $ 5,443 | $ 182 | $ (1,801) | $ 29 | $ 3,853 |
| Stock-based compensation | — | 8 | — | — | 8 |
| RSUs vested and released | 17 | (17) | — | — | — |
| Comprehensive income (loss) | — | — | (364) | 10 | (354) |
| **Balance as at June 30, 2020** | $ 5,460 | $ 173 | $ (2,165) | $ 39 | $ 3,507 |

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

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

| | | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|---|
| | Note | 2021 | 2020 | 2021 | 2020 |
| **Cash provided by (used in):** | | | | | |
| Operating activities | | | | | |
| Net earnings (loss) | | **$ 68** | $ (80) | **$ 51** | $ (364) |
| Adjustments for: | | | | | |
| Deferred income tax expense (recovery) | 15 | **17** | (61) | **(2)** | (63) |
| Inventory Impairment | 5 | **(1)** | (29) | **5** | — |
| Depletion and depreciation | 3, 5 | **108** | 93 | **216** | 217 |
| Exploration expense | 4 | **—** | — | **—** | 366 |
| Stock-based compensation | 9 | **(13)** | (17) | **(21)** | (13) |
| Unrealized net (gain) loss on foreign exchange | 12 | **(41)** | (114) | **(84)** | 153 |
| Unrealized net (gain) loss on commodity risk management | 18 | **27** | 267 | **115** | (161) |
| Amortization of debt discount and debt issue costs | 6 | **2** | 2 | **4** | 4 |
| Gain on asset dispositions | 3, 5 | **(4)** | — | **(4)** | (6) |
| Debt extinguishment expense | 13 | **5** | — | **5** | — |
| Other | | **2** | 2 | **3** | 4 |
| Decommissioning expenditures | 7 | **—** | — | **(2)** | (2) |
| Payments on onerous contracts | 7 | **(6)** | — | **(12)** | — |
| Net change in other liabilities | | **(4)** | 6 | **7** | 3 |
| Funds flow from operating activities | | **160** | 69 | **281** | 138 |
| Net change in non-cash working capital items | 16 | **20** | 48 | **(89)** | 78 |
| **Net cash provided by (used in) operating activities** | | **180** | 117 | **192** | 216 |
| Investing activities | | | | | |
| Capital expenditures | 3 | **(71)** | (20) | **(141)** | (74) |
| Net proceeds on dispositions | 3 | **44** | — | **44** | 6 |
| Net change in non-cash working capital items | 16 | **(46)** | (30) | **(25)** | (41) |
| **Net cash provided by (used in) investing activities** | | **(73)** | (50) | **(122)** | (109) |
| Financing activities | | | | | |
| Issuance of senior unsecured notes | 6 | **—** | — | **769** | 1,581 |
| Repayment and redemption of long-term debt | 6 | **—** | — | **(763)** | (1,723) |
| Debt redemption premium and refinancing costs | 6 | **—** | (1) | **(19)** | (49) |
| Issue of shares, net of issue costs | | **2** | — | **4** | — |
| Receipts on leased assets | 16 | **—** | 1 | **1** | 1 |
| Payments on leased liabilities | 16 | **(7)** | (7) | **(14)** | (13) |
| **Net cash provided by (used in) financing activities** | | **(5)** | (7) | **(22)** | (203) |
| **Effect of exchange rate changes on cash and cash equivalents held in foreign currency** | | **3** | (2) | **(3)** | 10 |
| Change in cash and cash equivalents | | **105** | 58 | **45** | (86) |
| Cash and cash equivalents, beginning of period | | **54** | 62 | **114** | 206 |
| Cash and cash equivalents, end of period | | **$ 159** | **$ 120** | **$ 159** | **$ 120** |

*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 400 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

The unaudited interim consolidated financial statements ("interim consolidated financial statements") were prepared using the same accounting policies and methods as those used in the Corporation's audited consolidated financial statements for the year ended December 31, 2020. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting ("IAS 34"). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board ("IASB"), has been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 4 of the Corporation's audited consolidated financial statements for the year ended December 31, 2020. These interim consolidated financial statements should be read in conjunction with the Corporation's audited 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 a novel strain of coronavirus ("COVID-19"). COVID-19 continues to impact worldwide demand for crude oil and therefore global commodity markets. Price volatility remains largely due to market sensitivity to COVID-19 related news including vaccine breakthroughs and rollouts, and the resurgence of COVID-19 cases and developing variants of concern.

The continued impact on capital and financial markets on a macro-scale present uncertainty and risk with respect to the Corporation's performance, and estimates and assumptions used in the preparation of its financial results.

These interim consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation's functional currency and were approved by the Corporation's Audit Committee on July 22, 2021.

## 3. PROPERTY, PLANT AND EQUIPMENT

| | Crude oil | Transportation and storage | Right-of-use assets | Corporate assets | Total |
|---|---|---|---|---|---|
| **Cost** | | | | | |
| Balance as at December 31, 2020 | $ 9,245 | $ 88 | $ 296 | $ 78 | $ 9,707 |
| Additions | 142 | — | 8 | — | 150 |
| Dispositions | — | (39) | — | — | (39) |
| Change in decommissioning liabilities | 7 | (2) | — | — | 5 |
| **Balance as at June 30, 2021** | **$ 9,394** | **$ 47** | **$ 304** | **$ 78** | **$ 9,823** |
| **Accumulated depletion and depreciation** | | | | | |
| Balance as at December 31, 2020 | $ 3,580 | $ 32 | $ 53 | $ 49 | $ 3,714 |
| Depletion and depreciation | 201 | — | 13 | 2 | 216 |
| **Balance as at June 30, 2021** | **$ 3,781** | **$ 32** | **$ 66** | **$ 51** | **$ 3,930** |
| **Carrying amounts** | | | | | |
| Balance as at December 31, 2020 | $ 5,665 | $ 56 | $ 243 | $ 29 | $ 5,993 |
| **Balance as at June 30, 2021** | **$ 5,613** | **$ 15** | **$ 238** | **$ 27** | **$ 5,893** |

During the quarter, the Corporation completed the sale of non-core industrial lands near Edmonton for cash proceeds of approximately $44 million, and a gain on sale of $4 million was recognized.

As at June 30, 2021, property, plant and equipment was assessed for impairment and no impairment was recognized. Included in the cost of property, plant and equipment is $254 million of assets that were under construction (December 31, 2020 – $244 million) and became available for use and will be depreciated subsequent to June 30, 2021.

## 4. EXPLORATION AND EVALUATION ASSETS

As at June 30, 2021, exploration and evaluation assets consist of $126 million in exploration projects which are pending the determination of proved or probable reserves. These assets were assessed for impairment and no impairment has been recognized on exploration and evaluation assets.

## 5. OTHER ASSETS

| As at | June 30, 2021 | December 31, 2020 |
|---|---|---|
| Non-current pipeline linefill[(a)] | **$ 168** | $ 176 |
| Finance sublease receivables | **16** | 17 |
| Intangible assets[(b)] | **6** | 7 |
| Deferred financing costs | **1** | 3 |
| Prepaid transportation costs[(c)] | **8** | 8 |
| | **199** | 211 |
| Less current portion, included in trade receivables and other | **(4)** | (5) |
| | **$ 195** | $ 206 |

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. During the six months ended June 30, 2021, an impairment of $5 million was recognized on long-term linefill.

b. As at June 30, 2021, intangible assets consist of software that is not an integral component of the related computer hardware. Depreciation of $1 million was recognized for the six months ended June 30, 2021 (year ended December 31, 2020 – $2 million). In 2020, the Corporation sold patents that were recorded at a nominal amount, and recognized a gain on asset disposition of $6 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.

## 6. LONG-TERM DEBT

| As at | June 30, 2021 | December 31, 2020 |
|---|---|---|
| **Second Lien:** | | |
| 6.5% senior secured second lien notes (June 30, 2021 - US$496 million; December 31, 2020 - US$496 million; due 2025) | **$ 615** | $ 633 |
| **Unsecured:** | | |
| 7.125% senior unsecured notes (June 30, 2021 - US$1.2 billion; December 31, 2020 - US$1.2 billion; due 2027) | **1,489** | 1,531 |
| 5.875% senior unsecured notes (June 30, 2021 - US$600 million; December 31, 2020 - US$nil; due 2029) | **744** | — |
| 7.0% senior unsecured notes (June 30, 2021 - US$nil; December 31, 2020 - US$600 million; due 2024) | **—** | 765 |
| | **2,848** | 2,929 |
| Debt redemption premium | **4** | 9 |
| Unamortized deferred debt discount and debt issue costs | **(32)** | (26) |
| | **$ 2,820** | $ 2,912 |

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2405 (December 31, 2020 – US$1 = C$1.2755).

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 included a prepayment option, recognized as at December 31, 2020, whereby the Corporation was required to make an estimate at the reporting date of the likelihood of the prepayment option being exercised.

As at June 30, 2021, the Corporation had $785 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $112 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 that remains outstanding.

Subsequent to the second quarter of 2021, on July 22, 2021, the Corporation announced that it had issued a notice to redeem US$100 million (approximately C$125 million) of the Corporation's 6.50% senior secured second lien notes due January 2025 at a redemption price of 103.25%, plus accrued and unpaid interest to, but not including, the redemption date. The redemption is expected to be completed on or about August 23, 2021. 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 under *IAS 10, Events After the Reporting Period*, as an adjusting subsequent event. Given the announced redemption, an expense was recognized as at June 30, 2021 to reflect the known likelihood of the prepayment option, with the expense reflecting the 103.25% redemption price. For the three and six months ended June 30, 2021, the Corporation recognized a debt redemption premium of

$4 million and an additional $1 million expense reflecting a portion of the remaining unamortized deferred debt issue costs on the announced redemption (Note 13).

## 7. PROVISIONS AND OTHER LIABILITIES

| As at | June 30, 2021 | December 31, 2020 |
|---|---|---|
| Lease liabilities[(a)] | $ 280 | $ 286 |
| Decommissioning provision[(b)] | 104 | 96 |
| Onerous contract provision[(c)] | 12 | 25 |
| Long-term incentive compensation liability[(d)] | 20 | 13 |
| Provisions and other liabilities | 416 | 420 |
| Less current portion | (44) | (56) |
| Non-current portion | $ 372 | $ 364 |

a. Lease liabilities:

| As at | June 30, 2021 | December 31, 2020 |
|---|---|---|
| Balance, beginning of period | $ 286 | $ 281 |
| Additions | 8 | 19 |
| Modifications | — | 7 |
| Payments | (27) | (47) |
| Interest expense | 13 | 26 |
| Balance, end of period | 280 | 286 |
| Less current portion | (27) | (28) |
| Non-current portion | $ 253 | $ 258 |

The Corporation's minimum lease payments are as follows:

| As at June 30 | 2021 |
|---|---|
| Within one year | $ 51 |
| Later than one year but not later than five years | 147 |
| Later than five years | 484 |
| Minimum lease payments | 682 |
| Amounts representing finance charges | (402) |
| Net minimum lease payments | $ 280 |

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 | June 30, 2021 | December 31, 2020 |
|---|---|---|
| Balance, beginning of period | **$ 96** | $ 71 |
| Changes in estimated life and estimated future cash flows | **1** | 4 |
| Changes in discount rates | **5** | 16 |
| Liabilities settled | **(2)** | (3) |
| Accretion | **4** | 8 |
| Balance, end of period | **104** | 96 |
| Less current portion | **(5)** | (3) |
| Non-current portion | **$ 99** | $ 93 |

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 $794 million (December 31, 2020 – $802 million). As at June 30, 2021, the Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 11.2% (December 31, 2020 – 11.7%) and an inflation rate of 2.1% (December 31, 2020 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2020 - periods up to the year 2066).

c. Onerous contract provision:

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. Liabilities settled during the six months ended June 30, 2021 were $12 million.

d. Long-term incentive compensation liability:

An $36 million cash-settled expense was recognized in the six months ended June 30, 2021 due to the increase in the Corporation's share price, and associated increase in value of cash-settled RSUs, PSUs and DSUs compared to December 31, 2020, which translates to an increased liability and expense at June 30, 2021.

## 8. 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:

| | Six months ended June 30, 2021 | | Year ended December 31, 2020 | |
|---|---|---|---|---|
| | Number of shares (thousands) | Amount | Number of shares (thousands) | Amount |
| Balance, beginning of year | **302,681** | **$ 5,460** | 299,508 | $ 5,443 |
| Issued upon exercise of stock options | **790** | **6** | 39 | — |
| Issued upon vesting and release of RSUs and PSUs | **3,245** | **19** | 3,134 | 17 |
| Balance, end of period | **306,716** | **$ 5,485** | 302,681 | $ 5,460 |

## 9. STOCK-BASED COMPENSATION

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Cash-settled expense (recovery)[i] | **$ 17** | $ 9 | **$ 36** | $ (9) |
| Equity-settled expense | **5** | 2 | **7** | 7 |
| Equity price risk management (gain) loss[ii] | **(18)** | (19) | **(37)** | (20) |
| Stock-based compensation | **$ 4** | $ (8) | **$ 6** | $ (22) |

*(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 18(d) for further details.*

A $36 million cash-settled expense was recognized during the six months ended June 30, 2021 due to the increase in the Corporation's share price, and associated increase in value of cash-settled RSUs, PSUs and DSUs compared to December 31, 2020, which translates to an increased liability and expense at June 30, 2021. As at June 30, 2021, the Corporation recognized a liability of $49 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2020 – $23 million). The current portion of $29 million is included within accounts payable and accrued liabilities and $20 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards.

## 10. REVENUES

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Sales from: | | | | |
| Production | **$ 813** | $ 181 | **$ 1,508** | $ 650 |
| Purchased product[i] | **187** | 118 | **385** | 297 |
| Petroleum revenue | **$ 1,000** | $ 299 | **$ 1,893** | $ 947 |
| Royalties | **(14)** | — | **(21)** | (6) |
| Petroleum revenue, net of royalties | **$ 986** | $ 299 | **$ 1,872** | $ 941 |
| Power revenue | **$ 21** | $ 6 | **$ 46** | $ 26 |
| Transportation revenue | **2** | 2 | **5** | 5 |
| Other revenue | **$ 23** | $ 8 | **$ 51** | $ 31 |
| Total revenues | **$ 1,009** | $ 307 | **$ 1,923** | $ 972 |

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

a. Disaggregation of revenue from contracts with customers

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

| | Three months ended June 30 | | | | | |
|---|---|---|---|---|---|---|
| | 2021 | | | 2020 | | |
| | Petroleum Revenue | | | Petroleum Revenue | | |
| | Proprietary | Third-party | Total | Proprietary | Third-party | Total |
| Country: | | | | | | |
| Canada | **$ 411** | **$ —** | **$ 411** | $ 84 | $ 3 | $ 87 |
| United States | **402** | **187** | **589** | 97 | 115 | 212 |
| | **$ 813** | **$ 187** | **$ 1,000** | $ 181 | $ 118 | $ 299 |

| | Six months ended June 30 | | | | | |
|---|---|---|---|---|---|---|
| | 2021 | | | 2020 | | |
| | Petroleum Revenue | | | Petroleum Revenue | | |
| | Proprietary | Third-party | Total | Proprietary | Third-party | Total |
| Country: | | | | | | |
| Canada | **$ 802** | **$ —** | **$ 802** | $ 392 | $ 34 | $ 426 |
| United States | **706** | **385** | **1,091** | 258 | 263 | 521 |
| | **$ 1,508** | **$ 385** | **$ 1,893** | $ 650 | $ 297 | $ 947 |

Other revenue recognized during the three and six months ended June 30, 2021 and 2020 is attributed to Canada.

b. Revenue-related assets

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

| As at | June 30, 2021 | December 31, 2020 |
|---|---|---|
| Petroleum revenue | **$ 369** | $ 249 |
| Other revenue | **8** | 4 |
| Total revenue-related assets | **$ 377** | $ 253 |

Revenue-related receivables are typically settled within 30 days. As at June 30, 2021 and December 31, 2020, there was no material expected credit loss required against revenue-related receivables.

## 11. DILUENT AND TRANSPORTATION

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2021 | 2020 | 2021 | 2020 |
| Diluent expense | **$ 324** | $ 128 | **$ 620** | $ 428 |
| Transportation and storage | **91** | 77 | **184** | 157 |
| Diluent and transportation | **$ 415** | $ 205 | **$ 804** | $ 585 |

## 12. FOREIGN EXCHANGE (GAIN) LOSS, NET

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Unrealized foreign exchange (gain) loss on: | | | | |
| Long-term debt | **$ (38)** | $ (116) | **$ (86)** | $ 162 |
| US$ denominated cash and cash equivalents | **(3)** | 2 | **2** | (9) |
| Unrealized net (gain) loss on foreign exchange | **(41)** | (114) | **(84)** | 153 |
| Realized (gain) loss on foreign exchange | **—** | (2) | **—** | 1 |
| Foreign exchange (gain) loss, net | **$ (41)** | $ (116) | **$ (84)** | $ 154 |

| | | | | |
|---|---|---|---|---|
| C$ equivalent of 1 US$ | | | | |
| Beginning of period | **1.2572** | 1.4120 | **1.2755** | 1.2965 |
| End of period | **1.2405** | 1.3616 | **1.2405** | 1.3616 |

## 13. NET FINANCE EXPENSE

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Interest expense on long-term debt | **$ 53** | $ 60 | **$ 111** | $ 124 |
| Interest expense on lease liabilities | **7** | 7 | **13** | 13 |
| Interest income | **—** | — | **—** | (2) |
| Net interest expense | **60** | 67 | **124** | 135 |
| Debt extinguishment expense | **5** | — | **5** | — |
| Accretion on provisions | **2** | 2 | **4** | 4 |
| Net finance expense | **$ 67** | $ 69 | **$ 133** | $ 139 |

For the three and six months ended June 30, 2021, debt extinguishment expense was recognized in association with the July 22, 2021 announced debt redemption and included a cumulative debt redemption premium of $4 million and associated unamortized deferred debt issue costs of $1 million. Refer to Note 6 for further details.

## 14. OTHER EXPENSES

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Contract cancellation[(i)] | **$ —** | $ 20 | **$ —** | $ 26 |
| Severance and restructuring | **—** | 2 | **—** | 4 |
| Other expenses | **$ —** | $ 22 | **$ —** | $ 30 |

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

## 15. INCOME TAX EXPENSE (RECOVERY)

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Current income tax expense (recovery) | **$ (2)** | $ (1) | **$ (2)** | $ (1) |
| Deferred income tax expense (recovery) | **17** | (61) | **(2)** | (63) |
| Income tax expense (recovery) | **$ 15** | $ (62) | **$ (4)** | $ (64) |

For the three and six months ended June 30, 2021, the Corporation recognized a $12 million deferred tax expense associated with the tax treatment of a prior year investment in pipeline access. The Corporation disputes the current Canada Revenue Agency assessment and is considering its alternatives.

## 16. SUPPLEMENTAL CASH FLOW DISCLOSURES

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Cash provided by (used in): | | | | |
| Trade receivables and other | **$ (57)** | $ (7) | **$ (174)** | $ 157 |
| Inventories | **(2)** | (7) | **(36)** | 27 |
| Accounts payable and accrued liabilities | **(14)** | (21) | **92** | (156) |
| Interest payable | **47** | 53 | **4** | 9 |
| | **$ (26)** | $ 18 | **$ (114)** | $ 37 |
| Changes in non-cash working capital relating to: | | | | |
| Operating | **$ 20** | $ 48 | **$ (89)** | $ 78 |
| Investing | **(46)** | (30) | **(25)** | (41) |
| | **$ (26)** | $ 18 | **$ (114)** | $ 37 |
| Cash and cash equivalents:[(a)] | | | | |
| Cash | **$ 159** | $ 120 | **$ 159** | $ 120 |
| Cash equivalents | **—** | — | **—** | — |
| | **$ 159** | $ 120 | **$ 159** | $ 120 |
| Cash interest paid | **$ —** | $ — | **$ 96** | $ 105 |

a. As at June 30, 2021, $6 million of the Corporation’s total cash and cash equivalents balance was held in U.S. dollars (June 30, 2020 – $90 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$1.2405 (June 30, 2020 – US$1=C$1.3616).

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, 2020 | $ 17 | $ 286 | $ 2,912 |
| Financing cash flow changes: | | | |
| Receipts on leased assets | (1) | — | — |
| Payments on leased liabilities | — | (14) | — |
| Issuance of senior unsecured notes | — | — | 769 |
| Repayment and redemption of long-term debt | — | — | (763) |
| Debt redemption premium and refinancing costs | — | — | (19) |
| Other cash and non-cash changes: | | | |
| Lease liabilities settled | — | (13) | — |
| Lease liabilities incurred | — | 8 | — |
| Interest expense on lease liabilities | — | 13 | — |
| Unrealized (gain) loss on foreign exchange | — | — | (86) |
| Debt redemption premium | — | — | 5 |
| Amortization of deferred debt discount and debt issue costs | — | — | 2 |
| **Balance as at June 30, 2021** | **$ 16** | **$ 280** | **$ 2,820** |

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

## 17. NET EARNINGS (LOSS) PER COMMON SHARE

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Net earnings (loss) | **$ 68** | $ (80) | **$ 51** | $ (364) |
| Weighted average common shares outstanding (millions)[(a)] | **307** | 303 | **305** | 302 |
| Dilutive effect of stock options, RSUs and PSUs (millions)[(b)] | **4** | — | **5** | — |
| Weighted average common shares outstanding – diluted (millions) | **311** | 303 | **310** | 302 |
| Net earnings (loss) per share, basic | **$ 0.22** | $ (0.26) | **$ 0.17** | $ (1.21) |
| Net earnings (loss) per share, diluted | **$ 0.22** | $ (0.26) | **$ 0.17** | $ (1.21) |

a. Weighted average common shares outstanding for the three months ended June 30, 2021 did not include any PSUs vested but not yet released (three months ended June 30, 2020 - 571,529 PSUs). Weighted average common shares outstanding for the six months ended June 30, 2021 includes 272,259 PSUs vested but not yet released (six months ended June 30, 2020 - 476,272 PSUs).

b. For the three and six months ended June 30, 2020, the Corporation incurred a net loss and therefore there was no dilutive effect of stock options, RSUs and PSUs. If the Corporation had recognized net earnings for the three and six months ended June 30, 2020, the dilutive effect of stock options, RSUs and PSUs would have been 3.6 million weighted average common shares.

## 18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

a. Fair values:

The carrying 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 | June 30, 2021 | | December 31, 2020 | |
|---|---|---|---|---|
| | Carrying amount | Fair value | Carrying amount | Fair value |
| Recurring measurements: | | | | |
| Financial assets | | | | |
| Risk management contracts | $ 56 | $ 56 | $ 27 | $ 27 |
| Financial liabilities | | | | |
| Long-term debt (Note 6) | $ 2,848 | $ 3,010 | $ 2,929 | $ 3,019 |
| Risk management contracts | $ 144 | $ 144 | $ 29 | $ 29 |

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 June 30, 2021 and is expected to fluctuate given the volatility in the debt and commodity price markets.

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

b. Risk management:

The Corporation's risk management assets and liabilities consist of WTI and light-heavy differential swaps, and if entered into, options, plus condensate 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 | June 30, 2021 | | | December 31, 2020 | | |
|---|---|---|---|---|---|---|
| | **Asset** | **Liability** | **Net** | **Asset** | **Liability** | **Net** |
| Gross amount | **$ 56** | **$ (167)** | **$ (111)** | $ 27 | $ (62) | $ (35) |
| Amount offset | **—** | **23** | **23** | — | 33 | 33 |
| Net amount | **$ 56** | **$ (144)** | **$ (88)** | $ 27 | $ (29) | $ (2) |
| | | | | | | |
| Current portion | **$ 25** | **$ (144)** | **$ (119)** | $ 6 | $ (29) | $ (23) |
| Non-current portion | **31** | **—** | **31** | 21 | — | 21 |
| Net amount | **$ 56** | **$ (144)** | **$ (88)** | $ 27 | $ (29) | $ (2) |

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 June 30:

| As at June 30 | 2021 | 2020 |
|---|---|---|
| Fair value of contracts, beginning of year | $ (2) | $ (77) |
| Fair value of contracts realized | 156 | 321 |
| Change in fair value of contracts | (242) | (140) |
| Fair value of contracts, end of period | **$ (88)** | $ 104 |

c. Commodity risk management:

The Corporation had the following financial commodity risk management contracts relating to crude oil sales and condensate purchases outstanding as at June 30, 2021:

| As at June 30, 2021 | | | |
|---|---|---|---|
| **Crude Oil Sales Contracts**[(ii)] | **Volumes (bbls/d)**[(i)] | **Term** | **Average Price (US$/bbl)**[(i)] |
| WTI:WCS[(iii)(iv)] Fixed Differential | 10,000 | Jul 1, 2021 - Sep 30, 2021 | $(11.05) |
| **Enhanced Fixed Price with Sold Put Option** | | | |
| WTI Fixed Price/Sold Put Option Strike Price | 29,000 | Jul 1, 2021 - Dec 31, 2021 | $46.18/$38.79 |
| **Condensate Purchase Contracts** | | | |
| WTI:Mont Belvieu Fixed Differential | 10,950 | Jul 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 | 37,500 | Jul 1, 2021 - Dec 31, 2021 | $2.60 |
| AECO Fixed Price | 5,000 | Jan 1, 2022 - Dec 31, 2023 | $2.50 |

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

*(ii) Incremental to these crude oil sales contracts, the Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months within a quarter.*

*(iii) West Texas Intermediate ("WTI") crude oil*

*(iv) Western Canadian Select ("WCS") crude oil blend*

Except for contracts to fix the spread between July and August 2021 WTI prices, the Corporation did not enter into any financial commodity risk management contracts subsequent to June 30, 2021.

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

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Realized loss (gain) on commodity risk management | **$ 87** | $ (215) | **$ 156** | $ (321) |
| Unrealized loss (gain) on commodity risk management | **27** | 267 | **115** | (161) |
| Commodity risk management (gain) loss, net | **$ 114** | $ 52 | **$ 271** | $ (482) |

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 June 30, 2021:

| **Commodity** | **Sensitivity Range** | **Increase** | **Decrease** |
|---|---|---|---|
| Crude oil commodity price | ± US$5.00 per bbl applied to WTI contracts | **$ (33)** | **$ 32** |
| Crude oil differential price (i) | ± US$5.00 per bbl applied to WTI:WCS differential contracts | **$ 6** | **$ (6)** |
| Condensate purchase price | ± 5% in condensate price as a percentage of WTI | **$ 9** | **$ (9)** |
| Natural gas purchase price | ± C$0.50 per GJ applied to natural gas contracts | **$ 5** | **$ (5)** |

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

d. 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 and the revaluation is recognized in stock-based compensation expense. 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 cash-settled RSUs and PSUs vesting between 2021 and 2023.

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Unrealized equity price risk management (gain) loss | **$ (18)** | $ (19) | **$ (29)** | $ (20) |
| Realized equity price risk management (gain) loss | **—** | — | **(8)** | — |
| Equity price risk management (gain) loss | **$ (18)** | $ (19) | **$ (37)** | $ (20) |

e. Credit risk management:

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward looking information to determine the appropriate loss allowance provisions. Credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to each counterparty's credit quality. A substantial portion of accounts receivable are with investment grade customers in the energy industry and are subject to normal industry credit risk. The Corporation has experienced no material loss in relation to trade receivables. As at June 30, 2021, the Corporation’s estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $448 million. All amounts receivable from commodity risk management activities are due from large Canadian banks with strong investment grade credit ratings. Counterparty default risk associated with the Corporation’s commodity risk management activities is also partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in note 24 of the Corporation’s 2020 annual consolidated financial statements.

The Corporation’s cash balances are used to fund the development of its properties. As a result, the primary objectives of the investment portfolio are low risk capital preservation and high liquidity. The cash balances are held in high interest savings accounts or are invested in high grade, liquid, short-term instruments such as bankers’ acceptances, commercial paper, money market deposits or similar instruments. The cash and cash equivalents balance at June 30, 2021 was $159 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 $159 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 periods of volatility is supported by the Corporation's financial framework including a strong commodity risk management program securing cash flow through 2021 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 three and a half years out, represented by US$496 million of senior unsecured notes due January 2025, of which US$100 million will be redeemed on or about August 23, 2021 as per the announced notice of redemption. None of the Corporation’s outstanding long-term debt contain financial maintenance covenants. Additionally, the Corporation's modified covenant-lite $800 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $400 million. If drawn in excess of $400 million, the Corporation is required to maintain a quarterly first lien net leverage ratio (first lien net debt to last twelve-month EBITDA) of 3.5 or less. Under the Corporation's credit facility, first lien net debt is calculated as debt under the credit facility plus other debt that is secured on a *pari passu* basis with the credit facility, less cash on hand.

## 19. CAPITAL MANAGEMENT

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

On 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 Corporation's earliest maturity date on outstanding debt is January 2025. As at June 30, 2021, the Corporation had $785 million of unutilized capacity under the $800 million revolving credit facility and had $112 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 in the first quarter of 2020.

The following table summarizes the Corporation's net debt:

| As at | Note | June 30, 2021 | December 31, 2020 |
|---|---|---|---|
| Long-term debt | 6 | **$ 2,820** | $ 2,912 |
| Cash and cash equivalents | | **(159)** | (114) |
| Net debt | | **$ 2,661** | $ 2,798 |

Net debt is an important measure used by management to analyze leverage and liquidity.

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

| | | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|---|
| | Note | 2021 | 2020 | 2021 | 2020 |
| Net cash provided by (used in) operating activities | | **$ 180** | $ 117 | **$ 192** | $ 216 |
| Net change in non-cash operating working capital items | 16 | **(20)** | (48) | **89** | (78) |
| Funds flow from (used in) operations | | **160** | 69 | **281** | 138 |
| Adjustments: | | | | | |
| Payments on onerous contracts | | **6** | — | **12** | — |
| Contract cancellation | | **—** | 20 | **—** | 26 |
| Adjusted funds flow | | **$ 166** | $ 89 | **$ 293** | $ 164 |

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 and non-recurring items from cash flows, the funds flow from (used in) operations and adjusted funds flow measures provide meaningful metrics for management by establishing a clear link between the Corporation's cash flows and the operating netbacks from the Christina Lake Project. Funds flow from (used in) operations and adjusted funds flow are not intended to represent net cash provided by (used in) operating activities.

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

## 20. COMMITMENTS AND CONTINGENCIES

a. Commitments

The Corporation’s commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at June 30, 2021:

| | | 2021 | | 2022 | | 2023 | | 2024 | | 2025 | Thereafter | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Transportation and storage[(i)] | $ | 197 | $ | 399 | $ | 440 | $ | 435 | $ | 411 | $ 5,657 | $ | 7,539 |
| Diluent purchases | | 100 | | 20 | | 17 | | — | | — | — | | 137 |
| Other operating commitments | | 11 | | 16 | | 16 | | 13 | | 12 | 36 | | 104 |
| Variable office lease costs | | 2 | | 4 | | 4 | | 4 | | 5 | 27 | | 46 |
| Capital commitments | | 35 | | — | | — | | — | | — | — | | 35 |
| **Commitments** | **$** | **345** | **$** | **439** | **$** | **477** | **$** | **452** | **$** | **428** | **$ 5,720** | **$** | **7,861** |

*(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 7(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.

## 21. SUBSEQUENT EVENT

On July 22, 2021, the Corporation announced that it had issued a notice to redeem US$100 million (approximately C$125 million) of the Corporation's 6.50% senior secured second lien notes due January 2025 at a redemption price of 103.25%, plus accrued and unpaid interest to, but not including, the redemption date. The redemption is expected to be completed on or about August 23, 2021. 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 under *IAS 10, Events After the Reporting Period*, as an adjusting subsequent event. Given the announced redemption, an expense was recognized as at June 30, 2021 to reflect the known likelihood of the prepayment option, with the expense reflecting the 103.25% redemption price. For the three and six months ended June 30, 2021, the Corporation recognized a debt redemption premium of $4 million and an additional $1 million expense reflecting a portion of the remaining unamortized deferred debt issue costs on the announced redemption for a total debt extinguishment expense of $5 million.