MEG ENERGY

Sustainable. Innovative. Responsible.

2021 Report to Shareholders, Management's Discussion and Analysis and Annual Financial Statements

For the year ended December 31, 2021

TSX | MEG

REPORT | 2021

REPORT TO SHAREHOLDERS FOR THE YEAR ENDED DECEMBER 31, 2021

Report to Shareholders for the year ended December 31, 2021

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

The Corporation's Non-GAAP and Other Financial Measures are detailed in the Advisory section of this report to shareholders. They include: cash operating netback, blend sales, bitumen realization, transportation and storage expense net of transportation revenue, operating expenses net of power revenue, non-energy operating costs, energy operating costs, adjusted funds flow, free cash flow and net debt.

MEG Energy Corp. reported full year 2021 operational and financial results on March 3, 2022.

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

“As we exit 2021, MEG is very well positioned from an operational and financial perspective to continue to deliver on its deleveraging and shareholder return strategy” said Derek Evans, President and Chief Executive Officer. “We expect to be in a position to initiate our share buyback program in the second quarter of 2022 which, combined with our ongoing debt reduction program, should drive continued shareholder value through 2022 and beyond.”

Highlights include:

- Adjusted funds flow of $799 million ($2.57 per share) and funds flow from operating activities of $753 million;
- Record bitumen production volumes for the fourth quarter and full year 2021 of 100,698 barrels per day (bbls/d) and 93,733 bbls/d, respectively;
- Operating expenses net of power revenue of $6.60 per barrel, including record low non-energy operating costs of $4.24 per barrel. Power revenue offset energy operating costs by 52%, resulting in energy operating costs net of power revenue of $2.36 per barrel;
- Total capital expenditures of $331 million in 2021, approximately 2% lower than budget, was primarily directed towards sustaining and maintenance activities, resulting in $468 million of free cash flow in 2021;
- Completed or announced the repayment of US$325 million (approximately $415 million) of outstanding indebtedness during 2021;
- Subsequent to year end, MEG issued a notice to redeem the remaining US$171 million (approximately $215 million) of MEG’s 6.50% senior secured second lien notes due January 2025. The redemption is expected to be completed on or about April 4, 2022; and
- Also subsequent to year end, MEG's Board of Directors approved the filing of an application with the Toronto Stock Exchange (“TSX”) for a normal course issuer bid (“NCIB”) which once approved would allow MEG to buy back up to 10% of its public float, as defined by the TSX, over a one-year period.

Blend Sales Pricing

MEG realized an average AWB blend sales price of US$57.59 per barrel during 2021 compared to US$28.07 per barrel in 2020. The increase in average AWB blend sales price year over year was primarily a result of the average WTI price increasing by US$28.51 per barrel. MEG sold 42% of its sales volumes at the premium-priced U.S. Gulf Coast ("USGC") in 2021 compared to 40% in 2020.

Transportation and storage expense net of transportation revenue averaged US$6.10 per barrel of AWB blend sales in 2021 compared to US$6.74 per barrel of AWB blend sales in 2020. The decrease was primarily due to the elimination of rail transportation in 2021 compared to 2020.

Operational Performance

Bitumen production averaged 93,733 bbls/d at a steam-oil ratio ("SOR") of 2.43 in 2021, compared to 82,441 bbls/d at a SOR of 2.32 in 2020. Increased steam utilization, improved field reliability, completed and ongoing well optimization and recompletion work all contributed to strong field-wide production performance in 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 and was completed mid-August 2020, as well as voluntary price-related production curtailments in April and May 2020.

Non-energy operating costs averaged $4.24 per barrel of bitumen sales in 2021 compared to $4.38 per barrel in 2020. Non-energy operating costs per barrel decreased slightly due to fixed costs being spread over increased sales volumes. Energy operating costs, net of power revenue, averaged $2.36 per barrel in 2021 compared to $1.80 per barrel in 2020. This increase year over year resulted from stronger natural gas prices and increased internal power consumption as production increased, partially offset by the strengthening of the Alberta power market. Power revenue, which includes the impact of physical risk management contracts on power sales, offset energy operating costs by 52% during 2021 compared to 45% in 2020.

General & administrative expense ("G&A") was relatively consistent year over year with $56 million, or $1.65 per barrel of production, in 2021 compared to $49 million, or $1.62 per barrel of production, in 2020.

Funds Flow from Operating Activities, Adjusted Funds Flow and Net Earnings (Loss)

The Corporation's cash operating netback averaged $33.37 per barrel in 2021 compared to $19.22 per barrel in 2020. This increase in cash operating netback was primarily driven by the increase in average bitumen realization due to the higher WTI price, partially offset by realized commodity price risk management losses in 2021 compared to realized commodity price risk management gains in 2020. The increased cash operating netback was the main driver for the increase in the Corporation's funds flow from operating activities and adjusted funds flow from $239 million and $275 million, respectively, in 2020 to $753 million and $799 million, respectively, in 2021.

The Corporation recognized net earnings of $283 million in 2021 compared to a net loss of $357 million in 2020. This increase in net earnings was primarily due to stronger global crude oil prices partially offset by a commodity price risk management loss. The net loss recognized during 2020 was impacted by the recognition of a $366 million exploration expense.

Capital Expenditures

Capital expenditures in 2021 totaled $331 million compared to $149 million in 2020. While capital invested in the year was primarily directed towards sustaining and maintenance activities, approximately 20% of total capital expenditures was directed toward 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. As previously disclosed, the total investment for this optimization initiative is approximately $125 million with approximately $50 million remaining to be invested in the first half of 2022.

Debt Repayment

MEG announced today that the Corporation has issued a notice to redeem the remaining US$171 million (approximately $215 million) of MEG's outstanding 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625%, plus accrued and unpaid interest to, but not including, the redemption date. The redemption is expected to be completed on or about April 4, 2022. Inclusive of the redemption, MEG will have redeemed in full the original US$750 million aggregate principal amount of the second lien notes.

Debt reduction over the last four years now totals approximately US$2 billion. Continued debt reduction remains a core focus of the Corporation.

Ongoing Debt Repayment and Intention to Initiate Capital Return to Shareholders

As MEG expects to soon reach its previously announced near-term net debt target of US$1.7 billion, MEG's Board of Directors approved today the filing of an application with the TSX for a NCIB which, once approved by the TSX, will allow MEG to initiate a share buyback program to buy back over the next twelve months up to 10% of the Corporation's public float, as defined by the TSX, up to a maximum of approximately 27.2 million common shares of MEG.

As previously announced, MEG intends to allocate approximately 25% of free cash flow generated to share buybacks with the remaining free cash flow applied to ongoing debt reduction until the Corporation's net debt balance reaches US$1.2 billion. In the current commodity price environment, MEG expects to reach this US$1.2 billion net debt target in the third quarter of 2022.

Once the US$1.2 billion net debt target is reached the Corporation intends to increase the percentage of free cash flow allocated to share buybacks to approximately 50% with the remainder applied to further debt reduction.

Sustainability

In 2021, the Corporation advanced its Environmental, Social and Governance ("ESG") objectives with the establishment of a mid-term target of 30% reduction in bitumen greenhouse gas ("GHG") emissions (scope 1 and scope 2) from 2013 levels by 2030. This target is in addition to the Corporation's previously established long-term target of reaching net zero GHG emissions (scope 1 and scope 2) by 2050. Also in 2021, the Corporation, along with four oil sands operators who collectively operate 90% of Canada's oil sands production, formed the Oil Sands Pathways to Net Zero Alliance with the objective of working with the Federal and Alberta governments to achieve net zero GHG emissions from oil sands operations by 2050. This Alliance has grown to six companies operating approximately 95% of Canada's oil sands production and is focused on building a major CO_2 capture and storage trunkline, connecting oil sands facilities in the Fort McMurray, Christina Lake and Cold Lake regions of Alberta, to a CO_2 sequestration hub near Cold Lake. This enabling infrastructure is a key element to achieving net zero GHG emissions by 2050.

The Corporation published its second ESG report in 2021 in an effort to provide consistent, relevant information that is useful to Shareholders and other Stakeholders to provide greater transparency on ESG and climate-related risks. The report is aligned with guidance from the Sustainability Accounting Standards Board and the recommendations of the Task Force on Climate-related Financial Disclosure. The ESG report also references the Global Reporting Initiative ("GRI") and the United Nations Sustainable Development Goals.

The Corporation continues to advance ESG and progress on priority topics: Climate Change and GHG Emissions, Water and Wastewater Management, Health and Safety, and Indigenous Relations, led by a strong governance model, safe and reliable operations and a dedicated team as reflected across ESG metrics.

ADVISORY

Forward-Looking Information

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

Non-GAAP and Other Financial Measures

Certain financial measures in this report to shareholders are non-GAAP financial measures or ratios, supplementary financial measures and capital management measures. These measures are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP and other financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Please refer to section 16 "Non-GAAP and Other Financial Measures" of the Corporation's year ended December 31, 2021 Management's Discussion and Analysis for detailed descriptions of these measures.

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the year ended December 31, 2021 was approved by the Corporation's Board of Directors on March 3, 2022. This MD&A should be read in conjunction with the Corporation's audited annual consolidated financial statements and notes thereto for the year ended December 31, 2021 and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the audited annual consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in millions of Canadian dollars, except where otherwise indicated.

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

Certain financial measures in this MD&A are non-GAAP financial measures or ratios, supplementary financial measures and capital management measures. These measures are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP and other financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A for further descriptions of the measures noted below.

1. *Non-GAAP financial measures and ratios:*
    - *Cash operating netback*
    - *Blend sales*
    - *Bitumen realization*
    - *Transportation and storage expense net of transportation revenue*
    - *Operating expenses net of power revenue*
    - *Per barrel figures associated with non-GAAP financial measures*
2. *Supplementary financial measures and ratios:*
    - *Non-energy operating costs*
    - *Energy operating costs*
    - *Per barrel figures associated with supplementary financial measures*
3. *Capital management measures:*
    - *Adjusted funds flow*
    - *Free cash flow*
    - *Net debt*

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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 approximately 410 square miles of mineral leases. GLJ Ltd. ("GLJ"), an independent qualified reserves and resources evaluator, 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. The report prepared by GLJ is dated effective as of December 31, 2021, with a preparation date of February 2, 2022. For information regarding MEG's estimated reserves contained in the report prepared by GLJ, please refer to the Corporation's most recently filed AIF, which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

The Christina Lake Project, which contains all of the Corporation's 2P reserves has regulatory approval in place for 210,000 bbls/d of production. At a design steam oil ratio ("SOR") of 2.4, MEG has developed oil processing capacity of approximately 100,000 bbls/d at its Christina Lake central plant facility, prior to any impact from scheduled maintenance activity or outages. The typical average annual production decline rate at the Christina Lake Project is approximately 10% to 15% and at an annual production level of approximately 100,000 bbls/d, MEG has a 2P reserve life index of approximately 55 years.

The Corporation has been able to realize production growth over time at the Christina Lake Project while minimizing GHG emissions intensity through the application of its proprietary technologies. Specifically, MEG's eMSAGP technology reduces the amount of steam required to produce a barrel of bitumen. MEG also uses cogeneration, also known as combined heat and power generation, to create steam and power from a single heat source. The application of eMSAGP and cogeneration have enabled MEG to lower its greenhouse gas ("GHG") emissions intensity more than 20% below the *in situ* industry volume weighted average calculated based on data reported to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. MEG achieved an average steam oil ratio of 2.4 in 2021 compared to the *in situ* industry volume weighted average of 3.0.[1]

Marketing Strategy

The Corporation employs a marketing strategy that delivers and sells its production to oil markets throughout North America and internationally. MEG owns, leases and contracts for services on multiple facilities to transport, store and deliver AWB to customers. MEG has 100,000 bbls/d of contracted AWB transportation capacity on the Flanagan South and Seaway pipeline systems ("FSP") providing pipeline transportation directly to U.S. Gulf Coast ("USGC") refineries and export terminals. MEG is also a shipper on the Trans Mountain Expansion Project which, when in service, will provide MEG with 20,000 bbls/d of contracted AWB transportation capacity to Canada's West Coast. MEG also has contracted oil storage capacity of approximately 2.5 million barrels in Alberta and strategic locations in the U.S., with marine export capacity at Beaumont, Texas in the USGC. This combination of pipeline access, storage capacity and marine export capacity comprises MEG's strategy of having diversified, long-term and reliable market access to world oil prices for its production.

MEG has a long-term commitment to deliver AWB on the Access Pipeline from its Christina Lake Project to the Edmonton market connecting to local refineries and export pipelines. The Access Pipeline is comprised of an AWB blend pipeline system and diluent pipeline system. The AWB blend pipeline system runs from the Christina Lake Project to Edmonton. The diluent pipeline system runs from the Edmonton area to MEG's Christina Lake Project and allows MEG to effectively manage its local and import sourced diluent supply for purposes of blending with its Christina Lake production. The diluent system receives volumes from numerous local diluent production streams and fractionation facilities as well as imported diluent volumes from inbound pipelines and rail terminals. The diluent system is well connected to key pipeline and storage systems in the Edmonton/Fort Saskatchewan corridor, including the Enbridge TEPPCO and Southern Lights import pipelines for access to Mont Belvieu supply. This system provides a range of diluent supply alternatives and helps to mitigate diluent supply and price risk.

[1] *Annual 2021 data as per the Alberta Energy Regulator ST53.*

In the Edmonton area, MEG has approximately 1.1 million barrels of contracted storage and terminalling capacity, including approximately 900,000 barrels of capacity contracted at the Stonefell Terminal. The Stonefell Terminal is connected to the Access Pipeline System and provides the Corporation with the ability to: (i) sell and deliver AWB to a variety of markets; (ii) access multiple sources of diluent; and (iii) store both bitumen blend and diluent in periods of market and transportation disruptions or constraints.

MEG has contracted for pipeline capacity, storage capacity and marine export capacity in the U.S. Gulf Coast area. Specifically, MEG has contracted for approximately 1.0 million barrels of storage capacity, along with marine export capacity, at Beaumont, Texas. MEG has also contracted for capacity on the Bayou Bridge pipeline and 350,000 barrels of storage capacity at St. James, Louisiana.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The economic environment in which the Corporation operates improved significantly in 2021 as the WTI benchmark price increased by 72% year-over-year, and the Corporation's production volumes increased by 14% due to increased capital expenditures on well development and less major planned maintenance. These factors contributed to increased funds flow from operating activities and adjusted funds flow, which allowed the Corporation to continue on its path of debt repayment with two debt repayments announced in 2021 totaling US$325 million and one announced on March 3, 2022, to be completed in April 2022, of US$171 million.

As the Corporation expects to soon reach its previously announced near-term net debt target of US$1.7 billion, the Corporation's Board of Directors approved today the filing of an application with the Toronto Stock Exchange ("TSX") for a normal course issuer bid ("NCIB") which, once approved by the TSX, will allow MEG to initiate a share buyback program to buy back over the next twelve months up to 10% of the Corporation's public float, as defined by the TSX up to a maximum of approximately 27.2 million common shares of the Corporation.

As previously announced, the Corporation intends to allocate approximately 25% of free cash flow generated to share buybacks with the remaining free cash flow applied to ongoing debt reduction until the Corporation's net debt balance reaches US$1.2 billion. In the current commodity price environment, the Corporation expects to reach this US$1.2 billion net debt target in the third quarter of 2022.

Once the US$1.2 billion net debt target is reached the Corporation intends to increase the percentage of free cash flow allocated to share buybacks to approximately 50% with the remainder applied to further debt reduction.

Financial Liquidity and Capital Resources

Throughout 2021 the Corporation continued to prioritize debt repayment with the redemption of US$100 million of the Corporation's 6.50% senior secured second lien notes. Subsequent to December 31, 2021, the Corporation redeemed an additional US$225 million and announced the redemption of the remaining balance of the 6.50% senior secured second lien notes of US$171 million. Post these redemptions, the Corporation will have repaid approximately US$2 billion of outstanding indebtedness since 2018 and remains committed to continued debt reduction as a key component of its capital allocation strategy in 2022.

The Corporation generated funds flow from operating activities of $753 million and adjusted funds flow of $799 million in 2021 compared to $239 million and $275 million, respectively, in 2020. The increase is consistent with the macro environment where the significant increase in crude oil prices was supported by global energy demand recovery. The Corporation's realized blend sales price averaged $72.20 per barrel in 2021 compared to $37.65 per barrel in 2020 resulting primarily from a 72% increase in the WTI benchmark price. This was partially offset by the Corporation's losses on commodity price risk management contracts which were put in place in the second half of 2020 to protect the internal funding of the Corporation's 2021 capital expenditures.

Capital expenditures were $331 million in 2021 compared to $149 million during 2020. The majority of the $331 million invested in 2021 was directed towards sustaining and maintenance activities as well as 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. As previously disclosed in 2021, the total investment for this optimization initiative is approximately $125 million with $75 million included in the 2021 capital expenditures and the remainder expected to be invested in the first half of 2022.

As at December 31, 2021 cash and cash equivalents were $361 million. The Corporation exited the year with net debt of $2.4 billion (US$1.9 billion).

Other Highlights

Annual bitumen production averaged 93,733 bbls/d in 2021 compared to 82,441 bbls/d in 2020. Increased steam utilization, improved field reliability, completed and ongoing well optimization and recompletion work all contributed to strong field-wide production performance in 2021. Average bitumen production in 2020 was impacted by a major planned turnaround at the Phase 1 and 2 facilities, which began in June 2020 and was completed mid-August 2020, as well as voluntary price-related production curtailments in April and May 2020 as the Corporation responded to market volatility. Production in 2021 was not impacted by turnaround activities.

The Corporation recognized net earnings of $283 million in 2021 compared to a net loss of $357 million during 2020. Increased net earnings during 2021 was primarily due to stronger global crude oil prices partially offset by a commodity price risk management loss. Also, the net loss during 2020 was impacted by the recognition of a $366 million exploration expense.

2022 Outlook

On November 29, 2021, the Corporation announced its 2022 capital budget of $375 million.

The Corporation is estimating 2022 non-energy operating costs and general and administrative ("G&A") expense to be in the range of $4.50 - $4.80 per barrel and $1.70 - $1.85 per barrel, respectively. The Corporation expects full year 2022 total transportation costs to average between US$7.50 to US$8.00 per barrel of AWB blend sales.

Average annual bitumen production for 2022 is expected to be 94,000 to 97,000 barrels per day and reflects the impact of a scheduled 30-day major planned turnaround at the Christina Lake Phase 2B facility in the second quarter of 2022 which is expected to impact full year production by approximately 6,000 barrels per day.

The Corporation has not entered into any WTI or WTI:WCS differential commodity risk management contracts for 2022.

Selected Operational and Financial Information

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

	Three months ended December 31		Year ended December 31	
($millions, except as indicated)	**2021**	**2020**	**2021**	**2020**
Bitumen production - bbls/d	100,698	91,030	93,733	82,441
Steam-oil ratio	2.42	2.31	2.43	2.32
Bitumen sales - bbls/d	98,894	95,731	92,138	82,722
Bitumen realization(1) - $/bbl	71.06	38.64	62.47	27.23
Operating expenses net of power revenue(1) - $/bbl	8.20	6.98	6.60	6.18
Non-energy operating costs(2) - $/bbl	4.56	4.70	4.24	4.38
Cash operating netback(1) - $/bbl	37.87	18.66	33.37	19.22
General & administrative expense - $/bbl of bitumen production volumes	1.58	1.65	1.65	1.62
Funds flow from operating activities	260	81	753	239
Adjusted funds flow(3)	266	84	799	275
Per share, diluted	0.85	0.27	2.57	0.90
Revenue	1,307	786	4,321	2,292
Net earnings (loss)	177	16	283	(357)
Per share, diluted	0.57	0.05	0.91	(1.18)
Capital expenditures	106	40	331	149
Net debt - C$(3)	2,401	2,798	2,401	2,798
Net debt - US$(3)	1,897	2,194	1,897	2,194

(1) Non-GAAP financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Supplementary financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.
(3) Capital management measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.

3. SUSTAINABILITY

The Corporation's approach to environmental, social and governance ("ESG") matters and sustainability reflects its understanding of the challenges and opportunities presented by climate change and the energy transition and its commitment to taking appropriate actions. The Corporation's business strategy recognizes the importance and momentum behind the low carbon energy transition, recognizes the increasing demand for responsibly developed low carbon energy and addresses the risks arising out of climate change concerns. Although the timing and impact of the energy transition is highly indeterminate, the Corporation is focused on enhancing its position as a sustainable low-cost producer and achieving net zero carbon emissions.

The Corporation remains committed to its long-term goal of reaching net zero Scope 1[1] and Scope 2[2] GHG emissions by 2050. In the third quarter of 2021, the Corporation adopted a mid-term target of reaching a 30% reduction in bitumen GHG emissions intensity (Scope 1 and Scope 2) from 2013 levels by 2030. In addition, the Corporation, along with five other oil sands operators that collectively represent about 95% of Canada's operated oil sands production, is part of the Oilsands Pathways to Net Zero ("Pathways") Alliance working collectively with the federal and Alberta governments to achieve net zero GHG emissions from oil sands operations by 2050. The Pathways Alliance proposes to reduce oil sands production emissions in three phases: Phase 1 (2021-2030), Phase

[1] Scope 1 refers to direct GHG emissions from sources that are owned or controlled by an organization.
[2] Scope 2 refers to indirect GHG emissions that result from the generation of purchased electricity, heating, cooling, or steam consumed at assets owned or controlled by an organization.

2 (2031-2040) and Phase 3 (2041-2050). In Phase 1, Pathways will focus on building out a CO_2 capture network in the oil sands producing region of northern Alberta. A key aspect of this network is a proposed CO_2 transportation line to gather CO_2 from more than 20 oil sands facilities and move it to a proposed sequestration hub in the Cold Lake area of Alberta for storage. The CO_2 transportation line would also be available to other industries in the region interested in capturing and storing CO_2. The Pathways Alliance is currently developing detailed project plans for Phase 1, including conducting feasibility studies for the transportation line and storage hub as well as pre-engineering work for capturing CO_2 at multiple oil sands facilities.

The Corporation continues to advance ESG and progress on priority topics: Climate Change and Greenhouse Gas Emissions, Water and Wastewater Management, Health and Safety, and Indigenous Relations, led by a strong governance model, safe and reliable operations and a dedicated team as reflected across ESG metrics.

The Corporation published its second ESG Report in the third quarter of 2021 in an effort to provide consistent, relevant information that is useful to Shareholders and to provide greater transparency on ESG and climate-related risks. The report is aligned with guidance from the Sustainability Accounting Standards Board ("SASB") and the recommendations of the Task Force on Climate-related Financial Disclosure ("TFCD"). The ESG report also references the Global Reporting Initiative (“GRI”) and the United Nations Sustainable Development Goals (“SDGs”).

For further details on the Corporation’s approach to ESG matters, please refer to the most recently filed AIF on www.sedar.com.

4. FOURTH QUARTER HIGHLIGHTS

The fourth quarter of 2021 was the strongest quarter of 2021 with an 11% increase in average bitumen production and an 81% increase in the WTI benchmark price compared to the same period of 2020.

The Corporation recognized net earnings of $177 million for the three months ended December 31, 2021 compared to $16 million for the three months ended December 31, 2020 primarily due to stronger global crude oil prices.

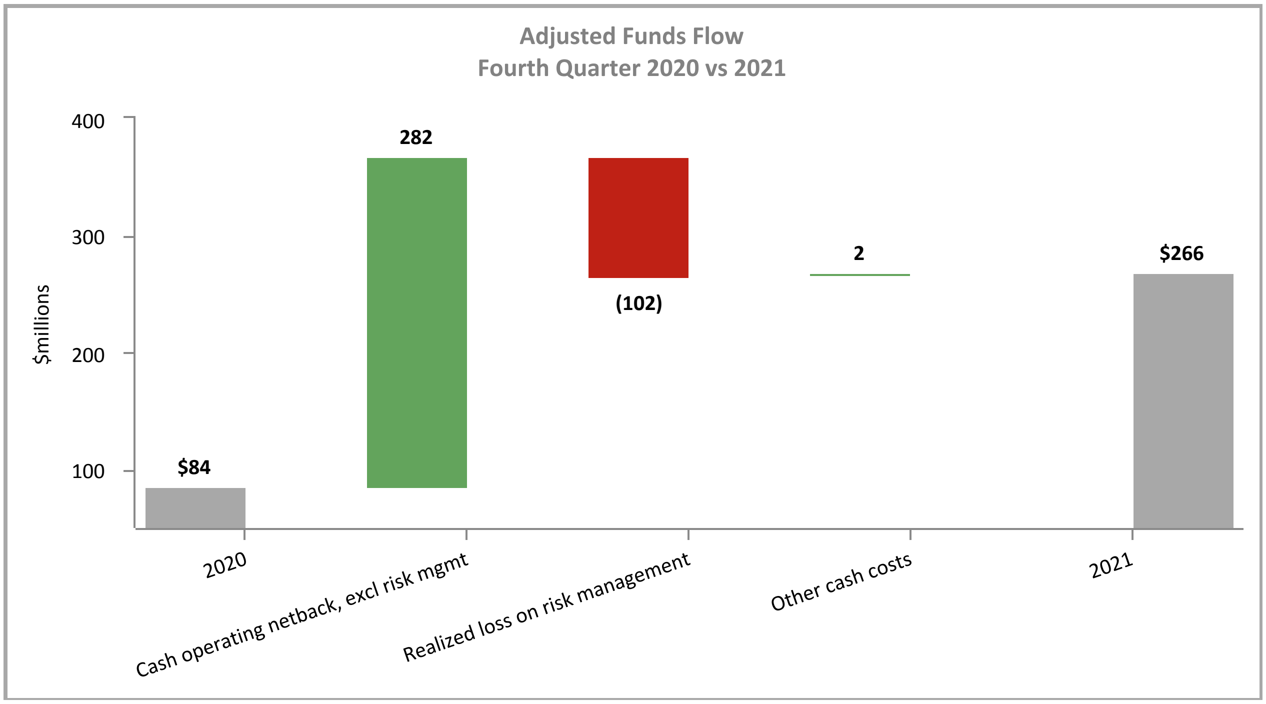
The following table is provided to reconcile the Corporation's funds flow from operating activities to adjusted funds flow for the fourth quarters of 2021 and 2020:

	Three months ended December 31	
($millions)	**2021**	**2020**
Funds flow from operating activities	**$ 260**	$ 81
Adjustments:		
Payments on onerous contract	**6**	—
Net change in other liabilities(1)	**—**	3
Adjusted funds flow(2)	**$ 266**	$ 84

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

(2) Capital management measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.

The Corporation generated funds flow from operating activities of $260 million and adjusted funds flow of $266 million in the three months ended December 31, 2021 compared to $81 million and $84 million, respectively, in the three months ended December 31, 2020. The increase was primarily driven by the Corporation's increased cash operating netback which was primarily 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 in the second half of 2020 to protect funding of the Corporation's 2021 capital program.



	Three months ended December 31			
	2021		2020	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Sales from production	**$ 1,060**		$ 559	
Sales from purchased product[1]	**252**		213	
Petroleum revenue	**1,312**		772	
Purchased product[1]	**(241)**		(197)	
Blend sales[2][3]	**$ 1,071**	**$ 82.43**	$ 575	$ 45.75
Diluent expense	**(425)**	**(11.37)**	(235)	(7.11)
Bitumen realization[3]	**646**	**71.06**	340	38.64
Transportation and storage expense net of transportation revenue[3][4]	**(103)**	**(11.39)**	(124)	(14.11)
Curtailment[5]	**—**	**—**	—	0.03
Royalties	**(32)**	**(3.54)**	(1)	(0.23)
Operating expenses net of power revenue[3]	**(75)**	**(8.20)**	(61)	(6.98)
Cash operating netback before realized commodity risk management	**436**	**47.93**	154	17.35
Realized gain (loss) on commodity risk management	**(91)**	**(10.06)**	11	1.31
Cash operating netback[3]	**$ 345**	**$ 37.87**	$ 165	$ 18.66
Bitumen sales volumes - bbls/d		**98,894**		95,731

(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) Non-GAAP financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.
(4) Transportation and storage expense net of transportation revenue includes costs associated with moving and storing blended barrels to optimize the timing of delivery, net of third-party recoveries on diluent transportation arrangements.
(5) 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. REVENUE

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

($millions)	2021	2020
Sales from:		
Production	$ **3,436**	$ 1,594
Purchased product[(1)]	**862**	650
Petroleum revenue	$ **4,298**	$ 2,244
Royalties	**(76)**	(9)
Petroleum revenue, net of royalties	$ **4,222**	$ 2,235
Power revenue	$ **87**	$ 45
Transportation revenue	**12**	12
Other revenue	$ **99**	$ 57
Total revenues	$ **4,321**	$ 2,292

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

During the year ended December 31, 2021, total revenues almost doubled from the same period of 2020 primarily as a result of the increase in the average blend sales price which was mostly driven by the increase in WTI prices.

6. NET EARNINGS (LOSS)

($millions, except per share amounts)	2021	2020
Net earnings (loss)	$ **283**	$ (357)
Per share, diluted	$ **0.91**	$ (1.18)

The Corporation recognized net earnings of $283 million during the year ended December 31, 2021 compared to a net loss of $357 million during the same period of 2020. Increased net earnings during the year ended December 31, 2021 was primarily due to stronger global crude oil prices partially offset by a commodity price risk management loss. The net loss during the year ended December 31, 2020 was impacted by the recognition of a $366 million exploration expense.

7. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	2021	2020
Bitumen production – bbls/d	**93,733**	82,441
Steam-oil ratio (SOR)	**2.43**	2.32

Bitumen Production

Bitumen production increased 14% during the year ended December 31, 2021 compared to the same period 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 2021. Also, there was less planned maintenance in 2021 compared to 2020 when there was a major planned turnaround at the Phase 1 and 2 facilities, which began in June 2020 and was completed mid-August 2020. In 2020, production was also impacted by voluntary price-related production curtailments in April and May 2020 in response the oil price environment.

Steam-Oil Ratio

The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is Steam-Oil Ratio ("SOR"), which is an efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR increased for the year ended December 31, 2021, compared to the same period of 2020, due to the timing of new well pairs and wells being brought into steam circulation and production.

Funds Flow from Operating Activities and Adjusted Funds Flow

During the year ended December 31, 2021, funds flow from operating activities and adjusted funds flow increased compared to the same period of 2020. The increase was driven by the Corporation's increased cash operating netback, which was primarily 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 was fully funded with internally generated cash flow.

The following table reconciles funds flow from operating activities to adjusted funds flow:

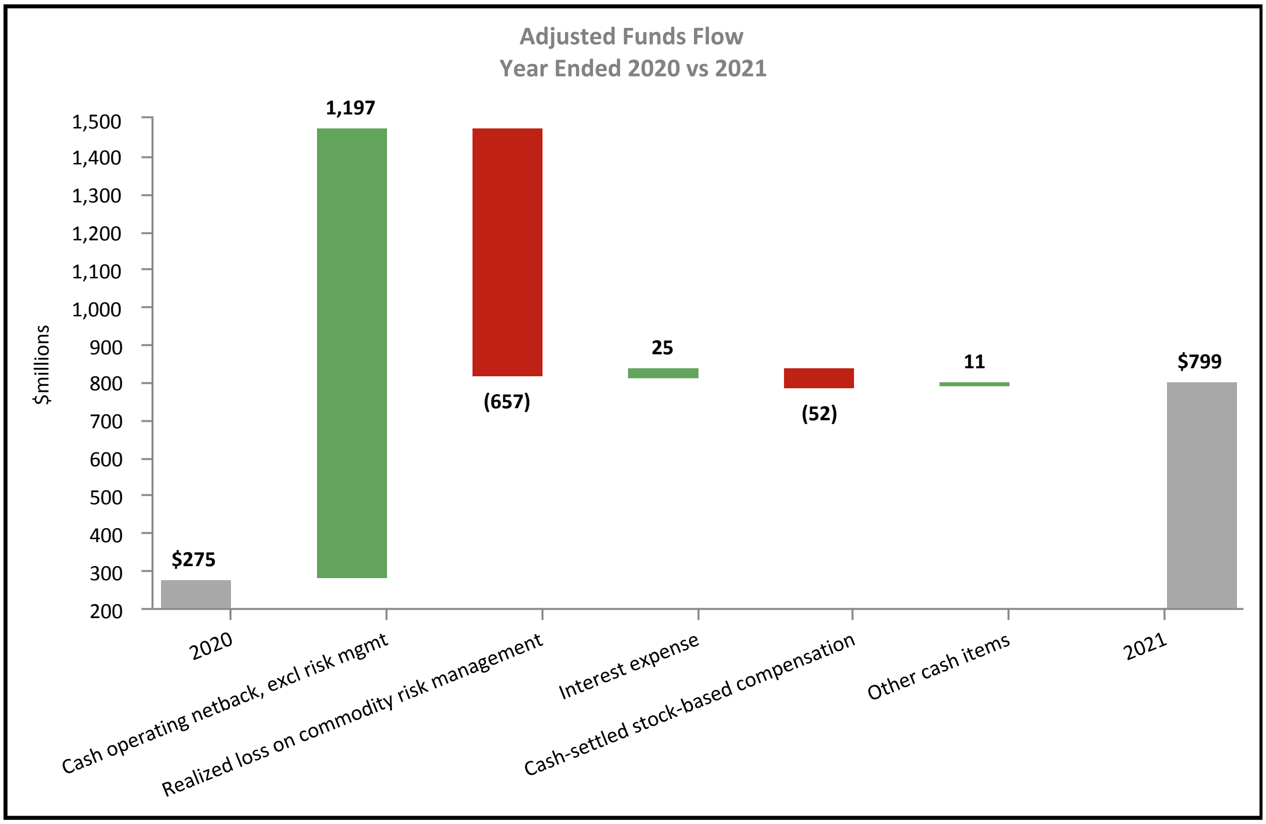
($millions)		**2021**		**2020**
Funds flow from operating activities	**$**	**753**	$	239
Adjustments:				
Payments on onerous contract		**25**		—
Settlement expense(1)		**21**		—
Net change in other liabilities(2)		**—**		3
Contract cancellation		**—**		33
Adjusted funds flow(3)	**$**	**799**	$	275

(1) *During 2021, the Corporation reached an agreement to settle the litigation matter commenced in 2014 relating to legacy issues involving a unit train transloading facility in Alberta. Under the agreement, the Corporation paid the sum of $21 million in full and final settlement of the claim and the claim has been discontinued.*

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

(3) *Capital management measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.*

Funds flow from operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as funds flow from operating activities excluding 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 non-recurring adjustments from cash flows, the adjusted funds flow measure provides a meaningful metric for management by establishing a clear link between the Corporation's cash flows and the cash operating netback.



Cash Operating Netback

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

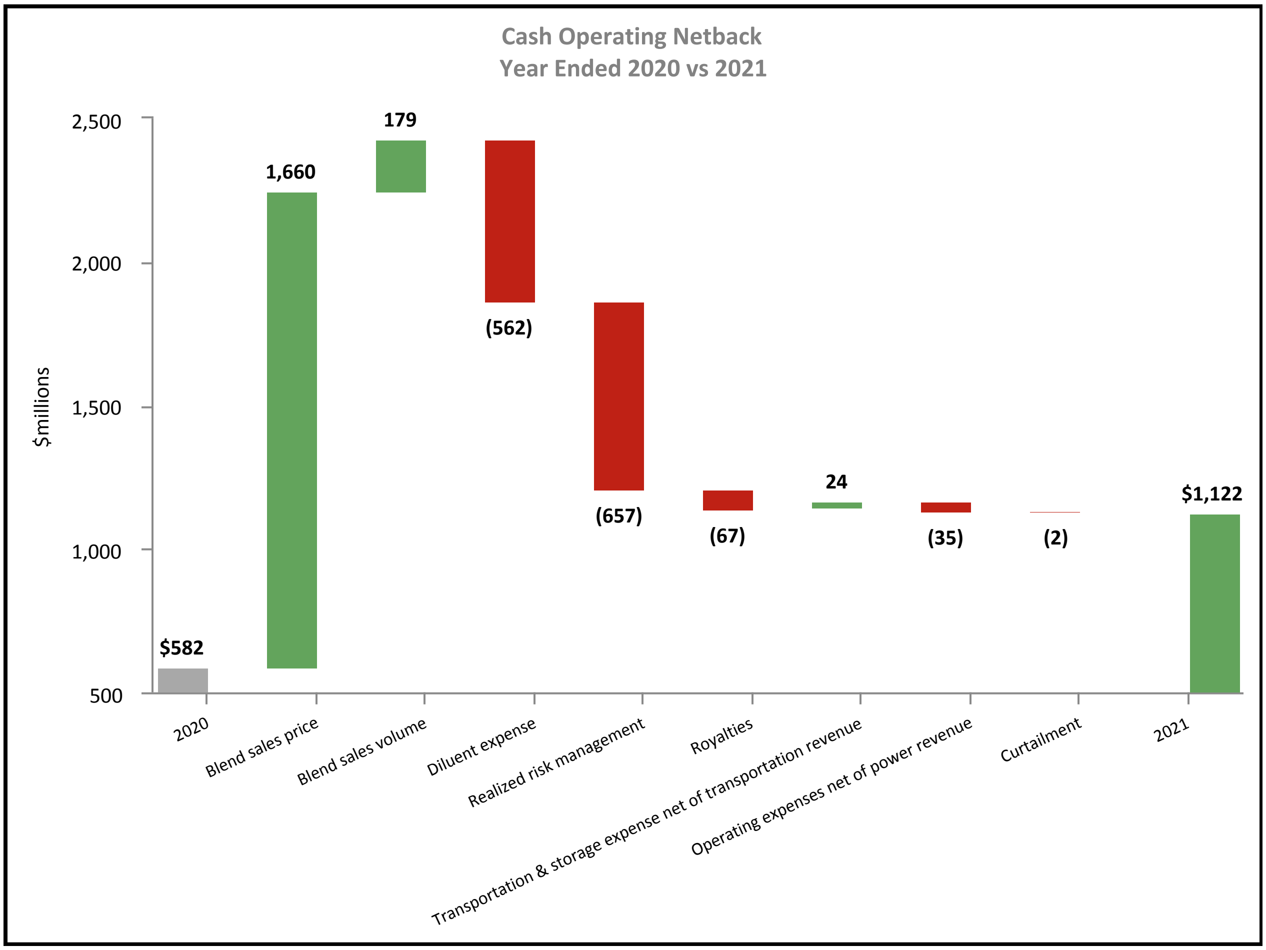
	2021		2020	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	**$ 3,436**		$ 1,594	
Sales from purchased product[1]	**862**		650	
Petroleum revenue	**4,298**		2,244	
Purchased product[1]	**(828)**		(613)	
Blend sales[2][3]	**$ 3,470**	**$ 72.20**	$ 1,631	$ 37.65
Diluent expense	**(1,369)**	**(9.73)**	(807)	(10.42)
Bitumen realization[3]	**2,101**	**62.47**	824	27.23
Transportation and storage expense net of transportation revenue[3][4]	**(367)**	**(10.93)**	(391)	(12.92)
Curtailment[5]	**—**	**—**	2	0.06
Royalties	**(76)**	**(2.25)**	(9)	(0.31)
Operating expenses net of power revenue[3]	**(222)**	**(6.60)**	(187)	(6.18)
Cash operating netback before realized commodity risk management	**1,436**	**42.69**	239	7.88
Realized gain (loss) on commodity risk management	**(314)**	**(9.32)**	343	11.34
Cash operating netback[3]	**$ 1,122**	**$ 33.37**	$ 582	$ 19.22
Bitumen sales volumes - bbls/d		**92,138**		82,722

(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) *Non-GAAP financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.*

(4) *Transportation and storage expense net of transportation revenue includes costs associated with moving and storing blended barrels to optimize the timing of delivery, net of third-party recoveries on diluent transportation arrangements.*

(5) *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.*

Blend sales includes sales from purchased product net of the cost of purchased product related to marketing 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 these assets, with the goal to strengthen cash operating netback. Marketing 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 less the 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. Also included in blend sales are net profits from third-party purchases and sales associated with asset optimization activities. The cost of diluent is impacted by Canadian and U.S. benchmark pricing, the amount of diluent required which is impacted by seasonality and pipeline specifications, the cost of transporting diluent to the production site from both Edmonton and USGC markets, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar. The cost of diluent purchased is partially offset by the sales of such diluent in blend volumes. Bitumen realization per barrel fluctuates primarily based on average benchmark prices and light:heavy oil differentials.

	2021		2020	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Sales from production	**$ 3,436**		$ 1,594	
Sales from purchased product[1]	**862**		650	
Petroleum revenue	**$ 4,298**		$ 2,244	
Purchased product[1]	**(828)**		(613)	
Blend sales[2][3]	**$ 3,470**	**$ 72.20**	$ 1,631	$ 37.65
Diluent expense	**(1,369)**	**(9.73)**	(807)	(10.42)
Bitumen realization[3]	**$ 2,101**	**$ 62.47**	$ 824	$ 27.23

(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) Non-GAAP financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.

Blend sales price increased by $34.55 per barrel, or 92%, during the year ended December 31, 2021 compared to the same period of 2020. The increase in blend sales price during the year ended December 31, 2021 is primarily due to a higher WTI price.

During the year ended December 31, 2021, diluent expense per barrel represents the cost of diluent that is unrecovered through blended sales. This per barrel cost was consistent with the prior year as the WTI:WCS differentials in 2021 were in line with the WTI:WCS differentials in 2020.

Total diluent expense was $1.4 billion during the year ended December 31, 2021 compared to $807 million during the same period of 2020. This translates to a cost per barrel of diluent during the year ended December 31, 2021 of $94.88 compared to $61.86 for the same period 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 Expense net of Transportation Revenue

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

	2021		2020	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Transportation and storage expense	**$ (379)**	**$ (11.28)**	$ (403)	$ (13.32)
Transportation revenue	**12**	**0.35**	12	0.40
Transportation and storage expense net of transportation revenue	**$ (367)**	**$ (10.93)**	$ (391)	$ (12.92)
Bitumen sales volumes - bbls/d		**92,138**		82,722

During the year ended December 31, 2021, total transportation and storage expense net of transportation revenue decreased by 6% compared to the same period of 2020. Transportation and storage expense net of transportation revenue on a per barrel basis also decreased during the year ended December 31, 2021, compared to the same period of 2020. The decrease is primarily due to the elimination of rail transportation in 2021 compared to the same period of 2020.

The Corporation partially mitigated the cost of unutilized transportation and storage assets through the purchase and sale of non-proprietary product, or asset optimization activities, which added $34 million, or $0.71 per barrel to blend sales, during the year ended December 31, 2021 compared to $37 million, or $0.86 per barrel to blend sales, during the same period of 2020. After considering the impact of asset optimization activities, transportation and storage expense net of transportation revenue was $10.22/bbl during 2021 compared to $12.06/bbl during

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.

	2021		2020	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Royalties	**$ (76)**	**$ (2.25)**	$ (9)	$ (0.31)

The WTI benchmark price increased 72% during the year ended December 31, 2021, compared to the same period of 2020, which increased the gross revenues for royalty purposes to which the royalty rate is applied. The average royalty rate in 2021 was 4.4% compared to 1.6% in 2020.

Operating Expenses net of Power Revenue

Operating expenses net of power revenue 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.

	2021		2020	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Non-energy operating costs(1)	**$ (143)**	**$ (4.24)**	$ (133)	$ (4.38)
Energy operating costs(1)	**(166)**	**(4.94)**	(99)	(3.29)
Power revenue	**87**	**2.58**	45	1.49
Operating expenses net of power revenue(2)	**$ (222)**	**$ (6.60)**	$ (187)	$ (6.18)
Average natural gas purchase price (C$/mcf)		**$ 4.16**		$ 2.72
Average realized power sales price (C$/Mwh)		**$ 90.10**		$ 47.81

(1) Supplementary financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Non-GAAP financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.

Total non-energy operating costs increased for the year ended December 31, 2021, compared to the same period of 2020. In the last nine months of 2020, the Corporation benefited 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. In response to this collapse, the Corporation took measures to reduce costs through salary rollbacks, reductions in staffing levels and vendor concessions. Also during this time in 2020, a major planned turnaround at the Phase 1 and 2 facilities was undertaken which decreased production-related activities and costs. Many of the cost reductions that occurred in 2020 were temporary, and consistent with the improved price environment and increased production-related activities in 2021, costs have normalized. Non-energy operating costs per barrel have decreased slightly due to fixed costs being spread over increased sales volumes.

Energy operating costs increased predominantly due to the AECO natural gas market strengthening by 63%, as well as increased consumption as production increased. This was partially offset by the Alberta power market strengthening by 120%. Power revenue, which includes the impact of physical risk management contracts on power sales, offset energy operating costs by 52% during the year ended December 31, 2021 compared to 45% during the same period of 2020.

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.

	2021		2020	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Realized gain (loss) on commodity risk management	**$ (314)**	**$ (9.32)**	$ 343	$ 11.34

Realized losses recognized on commodity risk management contracts were recognized during the year ended December 31, 2021 primarily due to the increase in the WTI prices in 2021 compared to the WTI fixed price contracts in place. Conversely, realized gains were recognized during the same period of 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	**2021**		
	Edmonton (US$/bbl)	**USGC (US$/bbl)**	**TOTAL (US$/bbl)**
(US$ per barrel of blend sales, unless otherwise indicated)	**Pipeline**	**Pipeline**	
WTI - benchmark	$ 67.91	$ 67.91	$ 67.91
Differential - WTI:AWB at sales point	(15.52)	(4.52)	(10.88)
Asset optimization(3)	—	1.33	0.56
Blend sales price(4)	52.39	64.72	57.59
Transportation and storage expense net of transportation revenue(1)	(2.04)	(11.66)	(6.10)
Transportation and storage from Christina Lake to Edmonton(2)	2.04	2.04	2.04
Blend sales price, net of transportation & storage at Edmonton	$ 52.39	$ 55.10	$ 53.53
Total blend sales - bbls/d	76,074	55,585	131,659
% of total sales	58 %	42 %	100 %

USGC sales price premium	**Edmonton (US$/bbl)**	**USGC (US$/bbl)**	**USGC premium (US$/bbl)**
Average blend sales price by location	$ 52.39	$ 64.72	$ 12.33
Transportation and storage expense net of transportation revenue(1)	(2.04)	(11.66)	(9.62)
Transportation and storage from Christina Lake to Edmonton(2)	2.04	2.04	—
Blend sales price, net of transportation & storage at Edmonton	$ 52.39	$ 55.10	$ 2.71

Blend sales distribution by sales market	**2020**			
	Edmonton (US$/bbl)		**USGC (US$/bbl)**	**TOTAL (US$/bbl)**
(US$ per barrel of blend sales, unless otherwise indicated)	**Pipeline**	**Rail**	**Pipeline**	
WTI - benchmark	$ 39.40	$ 39.40	$39.40	$ 39.40
Differential - WTI:AWB at sales point	(17.59)	(17.92)	(3.51)	(11.97)
Asset optimization(3)	—	—	1.59	0.64
Blend sales price(4)	21.81	21.48	37.48	28.07
Transportation and storage expense net of transportation revenue(1)	(1.99)	(4.98)	(12.74)	(6.74)
Transportation and storage from Christina Lake to Edmonton(2)	1.99	1.99	1.99	1.99
Blend sales price, net of transportation & storage at Edmonton	$ 21.81	$ 18.49	$26.73	$ 23.32
Total blend sales - bbls/d	53,831	16,865	47,651	118,347
% of total sales	46 %	14 %	40%	100 %

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

(1) *Defined as transportation and storage expenses net of transportation revenue, per barrel of blend sales volumes. For reference, total transportation and storage costs per barrel, based on bitumen sales volumes, were C$10.93 per barrel for the year ended December 31, 2021 compared to C$12.92 per barrel for the year ended December 31, 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 year ended December 31, 2021 these activities contributed US$1.33 per barrel to the blend sales price at the USGC (pipeline) compared to US$1.59 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 year ended December 31, 2021 would be US$10.33 per barrel compared to US$11.66 per barrel. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC (pipeline) during the year ended December 31, 2020 would be US$11.15 per barrel compared to US$12.74 per barrel.*

(4) *Non-GAAP financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.*

(5) *Results are translated at the average C$ per US$ foreign exchange rate of 1.2536 for the year ended December 31, 2021 and 1.3413 for the year ended December 31, 2020.*

On a transportation adjusted basis, the Corporation's USGC blend sales received a premium over the Edmonton blend sales of US$2.71 per barrel for the year ended December 31, 2021. This compares to a premium of US$5.70 per barrel at the USGC compared to the Edmonton market during the same period of 2020. The lower premium during the year ended December 31, 2021, compared to the same period of 2020, is primarily the result of improved pipeline egress capacity and increased storage capacity in Alberta which allowed the Corporation to eliminate rail utilization in 2021, narrowing the realized differentials at Edmonton and reducing the premium associated with USGC blend sales.

Capital Expenditures

($millions)	**2021**	**2020**
Sustaining and maintenance	**$ 302**	$ 105
Turnaround	**—**	25
Phase 2B brownfield expansion	**16**	14
eMVAPEX	**—**	11
Field infrastructure, corporate and other	**13**	3
	$ 331	$ 158
eMVAPEX goverment grant	**—**	(9)
	$ 331	$ 149

The increase in capital expenditures for the year ended December 31, 2021, compared to the same period 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.

The majority of the $331 million invested in 2021 was directed towards sustaining and maintenance activities including 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 total investment for this optimization initiative is approximately $125 million with approximately $50 million remaining to be invested in the first half of 2022.

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 completed during 2021. The total cost of the multi-year expansion was approximately $260 million. This investment provides additional steam capacity to the central plant facility, allowing for increased operational flexibility.

8. OUTLOOK

The Corporation's 2021 annual results were largely in line with the Corporation's most recent capital guidance update.

Summary of 2021 Guidance	**Annual Results**	**Revised Guidance (November 8, 2021)**	**Original Guidance (December 7, 2020)**
Bitumen production - annual average	93,733 bbls/d	92,500 - 93,500 bbls/d	86,000 - 90,000 bbls/d
Non-energy operating costs	$4.24 per bbl	$4.40 - $4.50 per bbl	$4.60 - $5.00 per bbl
G&A expense	$1.65 per bbl	$1.65 - $1.75 per bbl	$1.70 - $1.80 per bbl
Capital expenditures	$331 million	$335 million	$260 million

The Corporation's total transportation costs were US$6.10 per barrel of AWB blend sales for 2021 which is within the full year estimated range of US$6.00 to US$6.50 per barrel of AWB blend sales.

On November 29, 2021 the Corporation released its 2022 capital and operating budget.

The Corporation's 2022 production and operational guidance reflects the impact of a scheduled 30-day turnaround in the second quarter at its Christina Lake Phase 2B facility which is expected to impact full year production by approximately 6,000 bbls/d.

The Corporation has capacity to ship 100,000 bbls/d of AWB blend sales, on a pre-apportionment basis, to the USGC market via its committed capacity on the FSP. The Corporation expects to sell approximately two-thirds of its full year 2022 AWB blend sales volumes into the U.S. Gulf Coast via FSP with the remainder being sold into the Edmonton market. The Corporation expects full year 2022 total transportation costs to average between US$7.50 and US$8.00 per barrel of AWB blend sales.

The Corporation has not entered into any WTI or WTI:WCS differential commodity risk management contracts for 2022.

Summary of 2022 Guidance(1)	**Annual Results**
Bitumen production - annual average	94,000 - 97,000 bbls/d
Non-energy operating costs	$4.50 - $4.80 per bbl
G&A expense	$1.70 - $1.85 per bbl
Capital expenditures	$375 million

(1) 2022 guidance includes the impact of a scheduled 30-day turnaround at the Corporation's Christina Lake Phase 2B facility which is expected to impact production by approximately 6,000 bbls/d.

9. 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:

AVERAGE BENCHMARK COMMODITY PRICES	Year ended December 31		2021				2020			
	2021	2020	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Crude oil prices										
Brent (US$/bbl)	**70.74**	43.22	**79.78**	73.15	68.98	61.06	45.25	43.39	33.30	50.95
WTI (US$/bbl)	**67.91**	39.40	**77.19**	70.56	66.07	57.84	42.66	40.93	27.85	46.17
Differential – WTI:WCS – Edmonton (US$/bbl)	**(13.04)**	(12.60)	**(14.64)**	(13.58)	(11.49)	(12.47)	(9.30)	(9.09)	(11.47)	(20.53)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(14.71)**	(14.32)	**(16.40)**	(15.13)	(13.11)	(14.22)	(10.56)	(10.48)	(13.44)	(22.78)
AWB – Edmonton (US$/bbl)	**53.20**	25.08	**60.79**	55.43	52.96	43.62	32.10	30.45	14.41	23.39
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(4.60)**	(4.77)	**(6.40)**	(5.57)	(3.92)	(2.52)	(2.83)	(3.20)	(7.29)	(5.74)
AWB – U.S. Gulf Coast (US$/bbl)	**63.31**	34.63	**70.79**	64.99	62.15	55.32	39.83	37.73	20.56	40.43
Condensate prices										
Condensate at Edmonton (C$/bbl)	**85.52**	49.48	**99.70**	87.30	81.55	73.51	55.39	50.03	30.72	61.76
Condensate at Edmonton as % of WTI	**100.5%**	93.6%	**102.5%**	98.2%	100.5%	100.4%	99.6%	91.8%	79.6%	99.5%
Condensate at Mont Belvieu, Texas (US$/bbl)	**65.50**	32.18	**76.62**	68.19	61.18	56.00	38.52	33.52	17.43	39.27
Condensate at Mont Belvieu, Texas as a % of WTI	**96.5%**	81.7%	**99.3%**	96.6%	92.6%	96.8%	90.3%	81.9%	62.6%	85.1%
Natural gas prices										
AECO (C$/mcf)	**3.95**	2.43	**5.07**	3.92	3.37	3.43	2.88	2.48	2.21	2.26
Electric power prices										
Alberta power pool (C$/MWh)	**102.37**	46.53	**107.25**	100.27	104.73	97.25	46.05	43.75	29.94	66.38
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.2536**	1.3413	**1.2600**	1.2602	1.2280	1.2663	1.3031	1.3316	1.3860	1.3445
C$ equivalent of 1 US$ – period end	**1.2656**	1.2755	**1.2656**	1.2750	1.2405	1.2572	1.2755	1.3324	1.3616	1.4120

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.

The significant decline in global crude oil demand due to the effects of the COVID-19 pandemic impacted crude oil prices in 2020. Commodity prices have improved in 2021 in line with increased global demand.

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.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, used as fuel to generate steam for the thermal production process and to create steam and electricity from the Corporation's cogeneration facilities. The AECO natural gas price increased during the year ended December 31, 2021 compared to the same period of 2020 due to strong correlation with global gas prices, low storage levels coming out of the summer months and overall tight market conditions in North America heading into 2022.

Electric Power Prices

Electric power prices impact the price that the Corporation receives on the sale of surplus power from the Corporation's cogeneration facilities. The Alberta power pool price increased during the year ended December 31, 2021 compared to the same period of 2020 primarily as a result of extreme weather conditions in February and December 2021 as well as in response to higher natural gas input costs.

10. OTHER OPERATING RESULTS

General and Administrative

($millions, except as indicated)		2021		2020
General and administrative	**$**	**56**	$	49
General and administrative expense per barrel of production	**$**	**1.65**	$	1.62

G&A expense increased 16% during the year ended December 31, 2021 compared to the same period of 2020. In the last nine months of 2020, the Corporation benefited 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. In response to this collapse, the Corporation took measures to reduce costs through salary rollbacks, reductions in staffing levels and vendor concessions. Many of the cost reductions that occurred in 2020 were temporary, and consistent with the improved price environment and increased production-related activities in 2021, costs have normalized.

Depletion and Depreciation

($millions, except as indicated)		2021		2020
Depletion and depreciation expense	**$**	**450**	$	410
Depletion and depreciation expense per barrel of production	**$**	**13.15**	$	13.60

Total depletion and depreciation expense increased during the year ended December 31, 2021, compared to the same period of 2020, primarily due to the increase in production as well as higher average future development costs. The depletion and depreciation expense in 2020 was impacted by an accelerated depreciation expense of $13 million, or $0.43 per barrel.

Excluding the accelerated depreciation expense recognized in 2020, depletion and depreciation expense was $13.17 per barrel in 2020, which is consistent with the depletion and depreciation expense of $13.15 per barrel in 2021.

Exploration Expense

($millions)	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 year ended December 31, 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), Net

The Corporation enters into financial commodity risk management contracts to increase the predictability of the Corporation's cash flow by managing commodity price volatility. The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes. All financial commodity risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss).

Realized gains or losses on financial commodity risk management contracts are the result of contract settlements during the period. Unrealized gains or losses on financial commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.

($millions)	2021	2020
Realized gain (loss) on:		
Crude oil contracts(1)	**$ (365)**	$ 359
Condensate contracts(2)	**40**	(16)
Natural gas contracts(3)	**11**	—
Realized commodity risk management gain (loss)	**$ (314)**	$ 343
Unrealized gain (loss) on:		
Crude oil contracts(1)	**$ 57**	$ (13)
Condensate contracts(2)	**(33)**	66
Natural gas contracts(3)	**7**	(4)
Unrealized commodity risk management gain (loss)	**$ 31**	$ 49
Commodity risk management gain (loss)	**$ (283)**	$ 392

(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 year ended December 31, 2021, the Corporation recognized a $283 million net loss from commodity risk management primarily due to losses on WTI fixed price contracts as market WTI prices for 2021 increased during the year. These losses were partially offset by gains on natural gas and condensate contracts, as the market prices of these commodities for current and future periods increased.

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

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

(US$/bbl)		2021		2020
WTI fixed price contracts[1][2]:				
Average fixed price	**$**	**46.66**	$	51.18
Average settlement price		**65.45**		39.58
Gain (loss) on WTI fixed price contracts	**$**	**(18.79)**	$	11.60
WTI:WCS fixed differential contracts:				
Average fixed differential	**$**	**(12.13)**	$	(20.15)
Average settlement differential		**(11.88)**		(11.90)
Gain (loss) on WTI:WCS fixed differential contracts	**$**	**(0.25)**	$	(8.25)
Condensate purchase contracts:				
Average fixed differential[3]	**$**	**(10.20)**	$	(5.54)
Average settlement differential		**(2.28)**		(7.63)
Gain (loss) on condensate purchase contracts	**$**	**7.92**	$	(2.09)
(C$/GJ)				
Natural gas purchase contracts:				
Average fixed price	**$**	**2.60**	$	—
Average settlement price		**3.41**		—
Gain (loss) on natural gas purchase contracts	**$**	**0.81**	$	—

(1) Includes WTI enhanced fixed price contracts with sold put options.
(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

($millions)		2021		2020
Cash-settled expense	**$**	**67**	$	1
Equity-settled expense		**15**		11
Equity price risk management gain[1]		**(56)**		(26)
Stock-based compensation expense (recovery)	**$**	**26**	$	(14)

(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 increase in cash-settled expense was primarily due to the increase in the Corporation's share price. The Corporation's common share price increased to $11.64 per share as at December 31, 2021, from its value of $4.45 per share as at December 31, 2020.

Equity-settled stock-based compensation expense increased for the year ended December 31, 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 is driven by the change in the Corporation's common share price relative to the notional value of the instruments. For the year ended December 31, 2021, an equity price risk management gain of $56 million was recognized on the increase in share price during the period.

Foreign Exchange Gain (Loss), Net

($millions)		2021		2020
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$**	**30**	$	36
Foreign currency risk management contracts[1]		**(7)**		—
US$ denominated cash and cash equivalents		**4**		11
Unrealized net gain (loss) on foreign exchange		**27**		47
Realized gain (loss) on foreign exchange		**2**		2
Foreign exchange gain (loss), net	**$**	**29**	$	49

C$ equivalent of 1 US$		
Beginning of period	**1.2755**	1.2965
End of period	**1.2656**	1.2755

(1) *Please refer to section 12 "Risk Management" of this MD&A for further details.*

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

For the year ended December 31, 2021, the Canadian dollar strengthened relative to the U.S. dollar by 1%, resulting in an unrealized foreign exchange gain of $27 million. For the year ended December 31, 2020, the Canadian dollar strengthened by 2%, resulting in an unrealized foreign exchange gain of $47 million.

Net Finance Expense

($millions)		2021		2020
Interest expense on long-term debt	**$**	**217**	$	241
Interest expense on lease liabilities		**26**		26
Interest income		**(2)**		(3)
Net interest expense		**241**		264
Accretion on provisions		**8**		8
Debt extinguishment expense		**18**		12
Net finance expense	**$**	**267**	$	284

Average effective interest rate	**6.7%**	6.9%

Interest expense on long-term debt decreased during the year ended December 31, 2021 compared to the same period of 2020 primarily 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% and the US$100 million debt redemption on August 23, 2021.

For the year ended December 31, 2021, debt extinguishment expense was recognized in association with the August 23, 2021 and January 18, 2022 debt redemptions as well as the debt redemption notice announced on March 3, 2022 and included a cumulative debt redemption premium of $12 million and associated unamortized deferred debt issue costs of $6 million. Refer to Note 10 of the 2021 audited annual consolidated financial statements for further details.

For the year ended December 31, 2020, debt extinguishment expense related to the refinancing of the 7.00% senior unsecured notes due March 2024 and included a cumulative debt redemption premium of $9 million and associated unamortized deferred debt issue costs of $3 million. Refer to Note 10 of the 2021 audited annual consolidated financial statements for further details.

Other Expenses

($millions)		**2021**		2020
Settlement expense	**$**	**21**	$	—
Contract cancellation		**—**		33
Onerous contract expense		**—**		25
Severance and restructuring		**—**		10
Other expenses	**$**	**21**	$	68

During 2021, the Corporation reached an agreement to settle the litigation matter commenced in 2014 relating to legacy issues involving a unit train transloading facility in Alberta. Under the agreement, the Corporation paid the sum of $21 million in full and final settlement of the claim and the claim has been discontinued.

During 2020, contract cancellation costs were incurred to mitigate rail sales contract exposure. The economic decision to divert sales volumes from rail contracts at Edmonton to the USGC more than recovered the cost of contract cancellations.

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

Income Tax

($millions)		**2021**		2020
Earnings (loss) before income taxes	**$**	**366**	$	(477)
Effective tax rate		**22.7 %**		25.2 %
Income tax expense (recovery)	**$**	**83**	$	(120)

For the year ended December 31, 2021, an income tax expense was recognized compared to an income tax recovery in the same period of 2020 primarily due to increased earnings before income taxes. Also, the Corporation recognized a $12 million deferred tax expense during the second quarter of 2021 associated with the tax treatment of a prior year investment in pipeline access. The Corporation disputes Canada Revenue Agency's assessment and continues to consider its alternatives.

As at December 31, 2021, the Corporation had approximately $7.2 billion of available Canadian tax pools, including $5.1 billion of non-capital losses, and recognized a deferred income tax asset of $296 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

The effective tax rate for the year ended December 31, 2021 differed from the Canadian statutory rate of 23% primarily due to the tax effect of foreign exchange gains and losses on the Corporation's long-term debt which is denominated in U.S. dollars, partially offset by the additional $12 million of deferred tax expense associated with the tax treatment of a prior year investment in pipeline access.

11. SUMMARY OF ANNUAL INFORMATION

($millions, except per share amounts)	2021	2020	2019
Revenue	$ 4,321	$ 2,292	$ 3,931
Net earnings (loss)	283	(357)	(62)
Per share - diluted	0.91	(1.18)	(0.21)
Total assets	7,593	7,224	7,866
Total non-current liabilities	2,885	3,276	3,455

Revenue

During 2021 revenue increased 89% from 2020 primarily as a result of the increase in the average blend sales price which was mostly driven by the increase in WTI prices.

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

Net Earnings (Loss)

The Corporation recognized net earnings of $283 million in 2021 compared to a net loss of $357 million in 2020. Increased net earnings during 2021 was primarily due to stronger global crude oil prices partially offset by a commodity price risk management loss. The net loss during 2020 was impacted by the recognition of a $366 million exploration expense.

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

Total Assets

Total assets at December 31, 2021 increased compared to December 31, 2020, mainly as a result of increased cash and receivables from higher funds flow from operating activities, partially offset by a decrease in property, plant and equipment as depreciation charges were in excess of capital expenditures.

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

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

Total Non-Current Liabilities

Total non-current liabilities as at December 31, 2021 decreased compared to December 31, 2020 primarily due to the repayment of long-term debt totaling $125 million as well as the reclassification of $285 million of long-term debt to current portion of long-term debt.

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

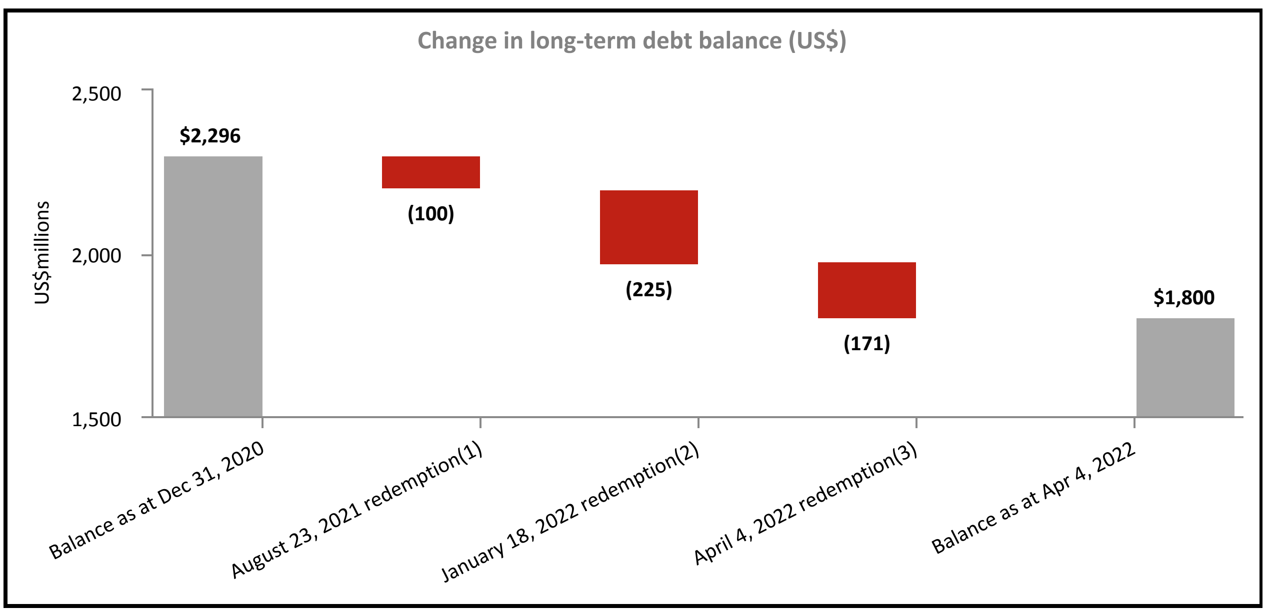
12. LIQUIDITY AND CAPITAL RESOURCES

($millions)	**December 31, 2021**	December 31, 2020
Second Lien:		
6.50% senior secured second lien notes (December 31, 2021 - US$396 million; due 2025; December 31, 2020 - US$496 million)	**$ 501**	$ 633
Unsecured:		
7.125% senior unsecured notes (December 31, 2021 - US$1.2 billion; due 2027; December 31, 2020 - US$1.2 billion)	**1,519**	1,531
5.875% senior unsecured notes (December 31, 2021 - US$600 million; due 2029; December 31, 2020 - US$nil)	**759**	—
7.0% senior unsecured notes (December 31, 2021 - US$nil; December 31, 2020 - US$600 million; due 2024)	**—**	765
Debt redemption premium	**8**	9
Unamortized deferred debt discount and debt issue costs	**(25)**	(26)
Current and long-term debt	**2,762**	2,912
Cash and cash equivalents	**(361)**	(114)
Net debt[(1)]	**$ 2,401**	$ 2,798

(1) *Net debt is reconciled to long-term debt in accordance with IFRS in Note 25 of the 2021 annual 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 redeemed and announced further redemptions of its long-term debt as noted below:



(1) *Redemption price of 103.25% plus accrued and unpaid interest on the 6.50% senior secured second lien notes.*
(2) *Redemption price of 101.625% plus accrued and unpaid interest on the 6.50% senior secured second lien notes.*
(3) *Redemption price of 101.625% plus accrued and unpaid interest on the remaining 6.50% senior secured second lien notes.*

The Corporation's cash and cash equivalents balance was $361 million as at December 31, 2021 compared to $114 million as at December 31, 2020 primarily as a result of the increase in cash flow from operating activities. Refer to the "Cash Flow Summary" section for further details.

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

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 credit risk management policies minimizing credit exposure on sales to primarily investment grade customers in the energy industry. After the January 2022 and April 2022 debt redemptions noted above, the Corporation's earliest maturing long-term debt is approximately five years out, represented by US$1.2 billion of senior unsecured notes due February 2027. None of the Corporation's outstanding long-term debt contain financial maintenance covenants. Additionally, the Corporation's modified covenant-lite $800 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $400 million. If drawn in excess of $400 million, the Corporation is required to maintain a quarterly first lien net leverage ratio (first lien net debt to last twelve-month EBITDA) of 3.5 or less. Under the Corporation's credit facility, first lien net debt is calculated as debt under the credit facility plus other debt that is secured on a pari passu basis with the credit facility, less cash-on-hand. None of the Corporation's outstanding long-term debt contain financial maintenance covenants and none are secured on a *pari passu* basis with the credit facility.

As at December 31, 2021, the Corporation had $794 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $100 million of unutilized capacity under the $500 million EDC Facility. A letter of credit of $15 million was issued under the revolving credit facility during the three months ended March 31, 2020 and $6 million remains outstanding as at December 31, 2021. Letters of credit issued under the revolving credit facility are not included in first lien net debt for purposes of calculating the first lien net leverage ratio.

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

Cash Flow Summary

	Year ended December 31	
($millions)	**2021**	**2020**
Net cash provided by (used in):		
Operating activities	**$ 690**	$ 302
Investing activities	**(281)**	(189)
Financing activities	**(165)**	(216)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**3**	11
Change in cash and cash equivalents	**$ 247**	$ (92)

Cash Flow – Operating Activities

Net cash provided by operating activities for the year ended December 31, 2021 increased compared to the same period of 2020, primarily due to higher benchmark crude oil prices.

Cash Flow – Investing Activities

Net cash used in investing activities increased during the year ended December 31, 2021 compared to the same period of 2020 reflecting increased capital spending over the year.

Cash Flow – Financing Activities

Net cash used in financing activities for the year ended December 31, 2021 decreased compared to the same period of 2020, primarily due to larger debt repayment and higher associated debt redemption and refinancing costs incurred during the year ended December 31, 2020.

13. 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 condensate purchases and natural gas purchases outstanding as at December 31, 2021:

As at December 31, 2021			
Condensate Purchase Contracts	**Volumes (bbls/d)(1)**	**Term**	**Average Price (US$/bbl)(1)**
WTI:Mont Belvieu Fixed Differential	200	Jan 1, 2022 - Dec 31, 2022	$(11.30)
Natural Gas Purchase Contracts	**Volumes (GJ/d)(1)**	**Term**	**Average Price (C$/GJ)(1)**
AECO Fixed Price	5,000	Jan 1, 2022 - Dec 31, 2023	$2.50

(1) *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.*

The Corporation did not enter into physical or financial commodity risk management contracts between December 31, 2021 and March 3, 2022.

Equity Price Risk Management

The Corporation occasionally 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, funds flow from operating activities and adjusted funds flow 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. Equity price risk management (gain) loss is recognized in stock-based compensation expense on the statement of earnings (loss) and the unrealized asset (liability) is included in risk management on the balance sheet.

($millions)	2021	2020
Unrealized equity price risk management (gain) loss	**$ (48)**	$ (26)
Realized equity price risk management (gain) loss	**(8)**	—
Equity price risk management (gain) loss	**$ (56)**	$ (26)

Foreign Currency Risk Management

The Corporation occasionally enters into short-term financial foreign currency risk management contracts to manage foreign currency risk on certain cash and cash equivalents. As at December 31, 2021, the Corporation had outstanding financial foreign currency risk management contracts on $334 million of cash and cash equivalents which fixed the exchange rate at 1.2897 Canadian dollar equivalent of $1 U.S. dollar. Foreign currency risk management (gain) loss is recognized in foreign exchange (gain) loss on the statement of earnings (loss) and the unrealized asset (liability) is included in risk management on the balance sheet.

14. SHARES OUTSTANDING

As at December 31, 2021, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	Units
Common shares	**306.9**
Convertible securities	
Stock options[1]	**2.5**
Equity-settled RSUs and PSUs	**6.6**

(1) 2.3 million stock options were exercisable as at December 31, 2021.

As at March 2, 2022, the Corporation had 307.0 million common shares, 2.2 million stock options and 6.6 million equity-settled RSUs and equity-settled PSUs outstanding, and 2.0 million stock options exercisable.

15. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

Contractual Obligations and Commitments

The information presented in the table below reflects management’s estimate of the contractual maturities of the Corporation’s obligations as at December 31, 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)	2022	2023	2024	2025	2026	Thereafter	Total
Commitments:							
Transportation and storage[1]	$ 404	$ 440	$ 440	$ 415	$ 377	$ 5,302	$ 7,378
Diluent purchases	152	17	—	—	—	—	169
Other operating commitments	16	16	14	13	13	23	95
Variable office lease costs	4	4	4	5	5	22	44
Capital commitments	16	—	—	—	—	—	16
Total Commitments	592	477	458	433	395	5,347	7,702
Other Obligations:							
Lease obligations	44	38	37	29	29	463	640
Current and long-term debt[2]	501	—	—	—	—	2,278	2,779
Interest on long-term debt[2]	161	153	153	153	153	108	881
Decommissioning obligation[3]	5	5	4	4	4	776	798
Total Commitments and Obligations	**$ 1,303**	**$ 673**	**$ 652**	**$ 619**	**$ 581**	**$ 8,972**	**$ 12,800**

(1) This represents transportation and storage commitments from 2022 to 2048, including pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet.

(2) This represents the scheduled principal repayments of the senior secured second lien notes, the senior unsecured notes, and associated interest payments based on interest and foreign exchange rates in effect on December 31, 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 was the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility in Alberta. During the last half of 2021, the Corporation reached an agreement to settle this litigation matter. Under the agreement, the Corporation paid the sum of $21 million in full and final settlement of the claim and the claim has been discontinued.

16. NON-GAAP AND OTHER FINANCIAL MEASURES

Certain financial measures in this MD&A are non-GAAP financial measures or ratios, supplementary financial measures and capital management measures. These measures are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP and other financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Adjusted Funds Flow and Free Cash Flow

Adjusted funds flow and free cash flow are capital management measures and are defined in the Corporation's annual financial statements. Adjusted funds flow and free cash flow are presented to assist management and investors in analyzing operating performance and cash flow generating ability. Funds flow from operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as funds flow from operating activities excluding items not considered part of ordinary continuing operating results. By excluding changes in non-recurring adjustments from cash flows, the adjusted funds flow measure provides a meaningful metric for management and investors by establishing a clear link between the Corporation's cash flows and the cash operating netback. 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.

The following table reconciles funds flow from operating activities to adjusted funds flow to free cash flow:

	Three months ended December 31		Year ended December 31	
($millions)	**2021**	**2020**	**2021**	**2020**
Funds flow from operating activities	**$ 260**	$ 81	**$ 753**	$ 239
Adjustments:				
Payments on onerous contract	**6**	—	**25**	—
Settlement expense[(1)]	**—**	—	**21**	—
Contract cancellation	**—**	—	**—**	33
Net change in other liabilities[(2)]	**—**	3	**—**	3
Adjusted funds flow	**266**	84	**799**	275
Capital expenditures	**(106)**	(38)	**(331)**	(149)
Free cash flow	**$ 160**	$ 46	**$ 468**	$ 126

(1) During 2021, the Corporation reached an agreement to settle the litigation matter commenced in 2014 relating to legacy issues involving a unit train transloading facility in Alberta. Under the agreement, the Corporation paid the sum of $21 million in full and final settlement of the claim and the claim has been discontinued.

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

Net Debt

Net debt is a capital management measure and is defined in the Corporation's annual financial statements. Net debt is an important measure used by management to analyze leverage and liquidity. Net debt is calculated as long-term debt plus current portion of long-term debt less cash and cash equivalents.

The following table reconciles the Corporation's current and long-term debt to net debt:

As at December 31	**2021**	**2020**
Long-term debt	**$ 2,477**	$ 2,912
Current portion of long-term debt	**285**	—
Cash and cash equivalents	**(361)**	(114)
Net debt - C$	**$ 2,401**	$ 2,798
Net debt - US$	**$ 1,897**	$ 2,194

Cash Operating Netback

Cash operating netback is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. 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 financial measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to generate cash flow for debt repayment, capital expenditures, or other uses. The per barrel calculation of cash operating netback is based on bitumen sales volume.

Total revenues, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to cash operating netback. A reconciliation from total revenues to cash operating netback has been provided below:

	Three months ended December 31		Year ended December 31	
($millions)	2021	2020	2021	2020
Total revenues	**$ 1,307**	$ 786	**$ 4,321**	$ 2,292
Diluent & transportation expense	**(532)**	(362)	**(1,748)**	(1,210)
Purchased product	**(241)**	(197)	**(828)**	(613)
Operating expenses	**(98)**	(74)	**(309)**	(232)
Curtailment	**—**	—	**—**	2
Cash operating netback before realized commodity risk management	**436**	153	**1,436**	239
Realized gain (loss) on commodity risk management	**(91)**	11	**(314)**	343
Cash operating netback	**$ 345**	$ 164	**$ 1,122**	$ 582

Blend Sales and Bitumen Realization

Blend sales and bitumen realization are non-GAAP financial measures, or ratios when expressed on a per barrel basis, and are used as a measure of the Corporation's marketing strategy by isolating petroleum revenue and costs associated with its produced and purchased products and excludes royalties. Their 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. Blend sales per barrel are based on blend sales volumes and bitumen realization per barrel is based on bitumen sales volumes.

Petroleum revenue, net of royalties, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to blend sales and bitumen realization. A reconciliation from petroleum revenue, net of royalties to blend sales and bitumen realization has been provided below:

	Three months ended December 31				Year ended December 31			
	2021		2020		2021		2020	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Petroleum revenue, net of royalties	**$ 1,280**		$ 771		**$ 4,222**		$ 2,235	
Royalties	**32**		1		**76**		9	
Petroleum revenue	**1,312**		772		**4,298**		2,244	
Purchased product	**(241)**		(197)		**(828)**		(613)	
Blend sales	**1,071**	**$ 82.43**	575	$ 45.75	**3,470**	**$ 72.20**	1,631	$ 37.65
Diluent expense	**(425)**	**(11.37)**	(235)	(7.11)	**(1,369)**	**(9.73)**	(807)	(10.42)
Bitumen realization	**$ 646**	**$ 71.06**	$ 340	$ 38.64	**$ 2,101**	**$ 62.47**	$ 824	$ 27.23

Transportation and Storage Expense net of Transportation Revenue

Transportation and storage expense net of transportation revenue is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. 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. Per barrel amounts are based on bitumen sales volumes.

It is used as a measure of the Corporation's marketing strategy by focusing on maximizing the realized AWB sales price after transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access. Per barrel amounts are based on bitumen sales volumes.

Diluent and transportation expense, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to transportation and storage expense. A reconciliation from diluent and transportation expense to transportation and storage expense has been provided below.

Other revenue, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to transportation revenue. A reconciliation from other revenue to transportation revenue has been provided below.

	Three months ended December 31				**Year ended December 31**			
	2021		**2020**		**2021**		**2020**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Diluent and transportation expense	**$ (532)**		$ (362)		**$(1,748)**		$(1,210)	
Less diluent expense	**425**		235		**1,369**		807	
Transportation and storage expense	**$ (107)**	**$ (11.77)**	$ (127)	$ (14.46)	**$ (379)**	**$(11.28)**	$ (403)	$(13.32)
Other revenue	**$ 27**		$ 16		**$ 99**		$ 57	
Less power revenue	**(23)**		(13)		**(87)**		(45)	
Transportation revenue	**$ 4**	**$ 0.38**	$ 3	$ 0.35	**$ 12**	**$ 0.35**	$ 12	$ 0.40
Transportation and storage expense net of transportation revenue	**$ (103)**	**$ (11.39)**	$ (124)	$ (14.11)	**$ (367)**	**$(10.93)**	$ (391)	$(12.92)

Operating Expenses net of Power Revenue

Operating expenses net of power revenue is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. 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. Per barrel amounts are based on bitumen sales volumes.

It is used as a measure of the Corporation’s cost to operate its facilities at the Christina Lake project after factoring in the benefits from selling excess power to offset energy costs.

Non-energy operating costs and energy operating costs are supplementary financial measures as they represent portions of operating expenses. Non-energy operating costs relate to production-related operating activities and energy operating costs reflect the cost of natural gas used as fuel to generate steam and power. Per barrel amounts are based on bitumen sales volumes.

Operating expenses is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss). Other revenue, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to power revenue. A reconciliation from other revenue to power revenue has been provided below.

	Three months ended December 31				Year ended December 31			
	2021		2020		2021		2020	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Non-energy operating costs	**$ (42)**	**$ (4.56)**	$ (33)	$ (4.70)	**$ (143)**	**$ (4.24)**	$ (133)	$ (4.38)
Energy operating costs	**(56)**	**(6.22)**	(41)	(3.73)	**(166)**	**(4.94)**	(99)	(3.29)
Operating expenses	**$ (98)**	**$(10.78)**	$ (74)	$ (8.43)	**$ (309)**	**$ (9.18)**	$ (232)	$ (7.67)
Other revenue	**$ 27**		$ 16		**$ 99**		$ 57	
Less transportation revenue	**(4)**		(3)		**(12)**		(12)	
Power revenue	**$ 23**	**$ 2.58**	$ 13	$ 1.45	**$ 87**	**$ 2.58**	$ 45	$ 1.49
Operating expenses net of power revenue	**$ (75)**	**$ (8.20)**	$ (61)	$ (6.98)	**$ (222)**	**$ (6.60)**	$ (187)	$ (6.18)

17. 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, 2021.

18. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the year ended December 31, 2021 and December 31, 2020, other than compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($millions)	2021	2020
Share-based compensation	**$ 36**	$ 6
Salaries and short-term employee benefits	**5**	5
	$ 41	$ 11

The increase in share-based compensation to key management personnel in 2021 is mainly due to the increase in the Corporation's share price and its impact on the value of the share-based awards.

19. RISK FACTORS

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

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

Risk Arising From Operations

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

- a decline in oil prices or widening of differentials between various crude oil prices;
- increases in the price applied to carbon emissions;
- the negative impacts of the COVID-19 pandemic and the related global economic downturn;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher SORs, or the inability to recognize continued or increased efficiencies from the Corporation’s production enhancement program which uses a combination of proprietary reservoir technologies (including eMSAGP and eMVAPEX) and processing plant enhancements, debottlenecking and brownfield expansions;
- reduced access to or an increase in the cost of diluent;
- an increase in the cost of natural gas;
- the reliability and maintenance of MEG's facilities;
- the safety and reliability of the Access Pipeline, other pipelines, tankage, railways and railcars and barges that transport MEG's products;
- the need to replace significant portions of existing wells, referred to as "workovers", or the need to drill additional wells;
- the cost to transport bitumen, diluent and bitumen blend, and the cost to dispose of certain by-products;
- the availability and cost of insurance and the inability to insure against certain types of losses;
- severe weather or catastrophic events such as fires, lightning, earthquakes, extreme cold weather, storms or explosions;
- seasonal weather patterns and the corresponding effects of the spring thaw on accessibility to MEG's properties;
- the availability of water supplies and the ability to transmit power on the electrical transmission grid;
- changes in the political landscape and/or legal, tax and regulatory regimes in Canada, the United States and elsewhere;
- the ability to obtain further approvals and permits for MEG's future projects;
- the ability to attract or access capital as a result of changing investor priorities and trends, including as a result of climate change, ESG initiatives, the adoption of decarbonization policies and the general stigmatization of the oil and gas industry;
- the availability of pipeline capacity and other transportation and storage facilities for MEG's bitumen blend;
- refining markets for MEG's bitumen blend;
- increased royalty payments resulting from changes in regulatory regimes;
- the cost of chemicals used in MEG's operations, including, but not limited to, in connection with water and/or oil treatment facilities;
- the availability of and access to drilling equipment; and
- the cost of compliance with applicable regulatory regimes, including, but not limited to, environmental regulation and Government of Alberta production curtailments, if any.

Status and Stage of Development

While the first three phases of the Christina Lake Project are operational, additional phases and other projects may not be completed on time (or at all), and the costs associated with additional phases may be greater than expected. At a design SOR of 2.4, the Corporation has developed oil processing capacity of approximately 100,000 bbls/d at its Christina Lake central plant facility, prior to any impact of scheduled maintenance activity or outages through the phased construction of the Christina Lake Project as well as several low-cost debottlenecking and expansion projects and the application of its proprietary reservoir technologies. While the investment in Phase 2B brownfield growth project central processing plan is complete, ramp up in production from the brownfield project, subsequent production enhancement and other projects may not be completed on budget, on time or at all, and the costs associated with additional phases and other projects, if and when approved, may be greater than the Corporation expects.

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

- future capital expenditures to be made by the Corporation and/or a determination by MEG not to devote capital expenditures to a given project;
- engineering and/or procurement performance falling below expected levels of output or efficiency;
- construction performance falling below expected levels of output or efficiency;
- denial or delays in receipt of regulatory approvals, additional requirements imposed by changes in laws or non-compliance with conditions imposed by regulatory approvals;
- a determination not to proceed with, or to delay, development of a given project;
- labour disputes or disruptions, declines in labour productivity or the unavailability of, or increased cost of, skilled labour;
- increases in the cost of materials;
- changes in project scope or errors in design;
- additional requirements imposed by changes in laws, including environmental laws and regulations;
- the availability of and access to drilling equipment; and
- severe weather or catastrophic events such as fire, earthquakes, extreme cold weather, storms or explosions.

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

Concentration of Production in Single Project

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

Long-Term Reliance on Third Parties

The Christina Lake Project depends on the availability and successful operation of certain infrastructure owned and operated by third parties or joint ventures with third parties, including (without limitation):

- pipelines for the transport of natural gas, diluent and blended bitumen;
- power transmission grids supplying and exporting electricity; and

- other third-party transportation infrastructure such as roads, airstrips, terminals and vessels.

For example, the Christina Lake Project depends on the successful operation of the Access Pipeline. Any interruption in the operation of the Access Pipeline or other pipeline infrastructure could have a material adverse impact on MEG by limiting its ability to transport blended bitumen to end markets and increasing MEG's cost for both sourcing diluent and transporting its blended bitumen. Such interruptions could result in all or a portion of MEG's production being shut-in. In addition, if certain pipelines currently forecast to be built or currently under construction are not completed on time, to the specifications MEG expects, or at all, MEG's anticipated costs could increase and MEG's operating results would be adversely affected.

The unavailability or decreased capacity of any or all of the infrastructure described above could negatively impact the operation of the Christina Lake Project, which in turn, may have a material adverse effect on MEG's results of operations, financial condition and prospects.

Claims Made by Indigenous Peoples

Indigenous Peoples have claimed indigenous title and rights to a substantial portion of western Canada. Certain Indigenous Peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the Regional Municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, indigenous title to large areas of lands surrounding Fort McMurray, including the lands on which the Christina Lake Project, MEG's other projects and most of the other oil sands operations in Alberta are located. Such claims, and other similar claims that may be initiated, if successful, could have a significant adverse effect on MEG and the Christina Lake Project and MEG's other projects.

On December 3, 2020, the Federal Government introduced Bill C-15, An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples which requires the Federal Government to ensure all Canadian laws are consistent with the United Nations Declaration on the Rights of Indigenous People ("UNDRIP"), implement an action plan to achieve UNDRIP's objectives and table a report on the process of aligning the laws of Canada and on the action plan. On June 21, 2021 Bill C-15 received Royal Assent and came immediately into force. Additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

Recently in British Columbia, an indigenous group was able to establish that cumulative effects within its traditional territory had reached a "tipping point" resulting in infringement of their treaty rights. The court determined that British Columbia could not authorize new activities within this First Nation's traditional territory, pending consultation and negotiation with the First Nation. However, this decision does not create binding precedent in Alberta, negotiations are ongoing between the Government of British Columbia and the First Nation respecting future authorizations (an interim agreement allowing emergency authorizations has been reached) and the decision was not appealed by the Government of British Columbia. While the long-term impacts of this decision on aboriginal law in Canada overall and in Alberta are not yet fully understood, a similar claim, if successful, that encompasses the Christina Lake Project and/or MEG's other projects could have a significant adverse effect on MEG.

RISKS RELATING TO ECONOMIC CONDITIONS, COMMODITY PRICING, DIFFERENTIALS AND EXCHANGE RATE FLUCTUATIONS

Fluctuations in Market Prices of Crude Oil, Bitumen Blend and Differentials

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

- the negative impacts of the COVID-19 pandemic, the proliferation of new COVID-19 variant strains, governmental policy and emergency response measures and any related economic downturn;

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

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

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

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

COVID-19 Pandemic and Related Impacts

The COVID-19 pandemic has affected, and may materially and adversely affect, MEG’s business, operating and financial results and liquidity. The severity, magnitude and duration of the COVID-19 pandemic, and the emergence of new variant strains of the COVID-19 virus, remains uncertain. While the full impact of this virus and the long-term worldwide reaction to it and impact from it remains uncertain, public health crises can result in volatility and disruptions in the supply, demand and pricing for petroleum products, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. Governmental reaction to the pandemic and restrictions and limitations applied by the government as a result, continued widespread growth in infections, travel restrictions, quarantines, or site closures as a result of the virus could, among other things, impact the ability of MEG’s employees and contractors to perform their duties, cause increased technology and security risk due to extended and company-wide telecommuting, lead to disruptions in MEG’s supply chain (including necessary contractors), increase the risk that oil storage could reach capacity in Canada and the U.S. Gulf Coast as a result of decreased demand, lead to a disruption in MEG’s resource acquisition or permitting activities and cause disruption in MEG’s relationship with customers.

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

- MEG’s revenue may be reduced if the pandemic results in an economic recession to the extent it leads to a prolonged decrease in the demand for crude oil, bitumen and bitumen blends;

- MEG’s operations may be disrupted or impaired, thus lowering our production level, if a significant portion of MEG’s employees or contractors are unable to work due to illness or if operations are suspended or temporarily shut-down or restricted due to control measures designed to contain the pandemic; and

- MEG’s sole operating facility at Christina Lake is subject to risks relating to a temporary suspension or physical interruption of its operations in the event a significant number of employees or contractors at the Christina Lake facility become infected with COVID-19, as it could place MEG’s entire site workforce at risk.

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

Russia Ukraine Conflict

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the peace and stability of the region and the world economy. Certain countries including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply of energy and high prices of oil and natural gas could have a significant adverse impact on the world economy. The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain.

General Economic Conditions, Business Environment, Inflation and Other Risks

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

Volatility in crude oil, bitumen blend, natural gas and diluent prices, fluctuations in interest rates, product supply and demand fundamentals, market competition, labour market supplies, risks associated with technology, risks of a widespread pandemic, MEG's ability to generate sufficient cash flow to meet its current and future obligations, MEG's ability to access external sources of debt and equity capital, general economic and business conditions, MEG's ability to make capital investments and the amounts of capital investments, risks associated with potential future lawsuits and regulations, assessments and audits (including income tax and royalties) against MEG (and its subsidiary), political and economic conditions in the geographic regions in which MEG and its subsidiary operate, difficulty or delays in obtaining necessary regulatory approvals, a significant decline in MEG's reputation, and such other risks and uncertainties, could individually or in the aggregate have a material adverse impact on MEG's business, prospects, financial condition, results of operation or cash flows. Challenging market conditions and the health of the economy as a whole may have a material adverse effect on MEG's results of operations, financial condition and prospects. There can be no assurance that any risk management steps taken by MEG with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks. While MEG does not believe that inflation has had a material effect on MEG's business, financial condition or results of operations to date, if operation or labour costs were to become subject to significant inflationary pressures, MEG may not be able to fully offset such higher costs. Inability or failure to do so could harm MEG's business, financial condition and results of operations.

The successful operation of the Corporation’s business will depend upon the availability of, and competition for, skilled labour and supply of required goods and services. There is a risk that the Corporation may have difficulty sourcing the required labour and goods and services required in its operations. The risk could manifest itself through an inability to recruit new employees or contractors without a dilution of talent, to train, develop and retain high quality and experienced employees or contractors without unacceptably high attrition, and to satisfy an employee's work/life balance and desire for competitive compensation. The labour market in Alberta is particularly tight due to a strengthening commodity price environment and increased field activities after a prolonged period of weak commodity prices, lack of work certainty, lower wages and COVID-19 which resulted in an exodus of skilled workers from the oil and gas industry. Labour, equipment and materials necessary for the Corporation's operations may also be in short supply, subject to substantial cost inflation, and the Corporation may experience substantial delays in transportation of materials given the impacts of COVID-19 on global supply chains and logistics.

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

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

Variations in Foreign Exchange Rates and Interest Rates

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

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

Hedging Strategies

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

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

Global Financial Markets

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

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

Climate Change Risks

Climate change may introduce new risks to MEG’s business including both physical risks and transitional risks. Certain of these climate change risks include the following:

Transitional Risks

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

Policy and Legal Risks

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

Marketing Risks

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

Reputational Risks

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

Negative public perceptions of the Alberta oil sands, where thermal oil productions operations are located, may impair the profitability of MEG's current or future oil sands projects. Further, with increasing public focus on climate change and GHG emissions, the scale of the global energy transition away from fossil fuels and the potential acceleration of the global energy transition, the reputations of oil and gas companies generally may become increasingly unfavourable. There are added social pressures which demand governments and companies to work to mitigate the risks associated with climate change, decrease GHG emissions and move towards decarbonization. Specifically, there is a reputational risk in connection with MEG's ability to meet increasing climate reporting and emission reduction expectations from key stakeholders. MEG has been actively preparing and adapting to manage and respond to investors' increasing expectations by proactively setting voluntary GHG and emission reduction targets, investing in energy efficiency and emissions reduction projects, integrating ESG across its business and linking executive compensation to progress on ESG goals and objectives.

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

Technology Risks

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

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

Physical Risks

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

ESG Related Goals

As a part of MEG's strategic priority to retain its position as a responsible leader in the energy industry, MEG has committed to various ESG targets, including the mid-term target of reaching a 30% reduction in bitumen GHG emissions intensity (Scope 1 and Scope 2) from 2013 levels by 2030 and the goal to achieve net zero Scope 1 and Scope 2 GHG emissions by 2050. To achieve these goals, among others, and to respond to changing market demand, MEG may incur additional costs and invest in new technologies and innovation. It is possible that the return on these investments may be less than expected, and government regulatory and financial support to assist in achieving these goals may be less than expected, each of which may have an adverse effect on MEG's business, financial condition and reputation.

Generally speaking, MEG's ESG targets, including those related to GHG emissions, and others associated with diversity, relationships with stakeholders, including Indigenous stakeholders and wildlife habitat reclamation, depend significantly on MEG's ability to execute its current business strategy, each of which can be impacted by the numerous risks and uncertainties associated with MEG's business and other industry factors.

MEG recognizes that its ability to adapt to and succeed in a lower-carbon economy will be compared against its peers. Investors and other stakeholders increasingly compare companies based on ESG-related performance, including climate-related performance. Failure by MEG to achieve its ESG targets, or a perception among key stakeholders that MEG's ESG targets are insufficient, could adversely affect, among other things, MEG's reputation and ability to attract capital. The continued focus on climate change by investors may lead to higher costs of capital for MEG as the pressure to reduce emissions increases. MEG's ability to attract capital may also be adversely impacted if financial institutions and investors incorporate sustainability and ESG considerations as a part of their portfolios or adopt restrictive decarbonization policies.

There is also a risk that some or all of the expected benefits and opportunities of achieving some or all of MEG's various ESG targets may fail to materialize, may cost more to achieve or may not occur within anticipated or stated timeframes. In addition, there are risks that the actions taken by MEG in implementing these targets and ambitions relating to ESG focus areas, may have a negative impact on MEG's business, including adverse impacts on operations or increased costs and capital expenditures, which may in turn negatively impact future operating and financial results.

Environmental and Regulatory Risks

Environmental considerations

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

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

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

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

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

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

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

Greenhouse Gas Regulations

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

Draft regulations for the Clean Fuel Standard (the "Clean Fuel Regulations") were released in December 2020 and were open for public comment until March 3, 2021. As proposed, the Clean Fuel Regulations only apply to liquid fuels, not gaseous and solid fuels, and will apply to producers or importers of gasoline, diesel, kerosene and light and heavy fuel oils (referred to as "primary suppliers"). Although the Clean Fuel Regulations, as proposed, do not apply to the Corporation's production of thermal oil, it is possible that, as a result of public comment on the proposed Regulations or otherwise, the Clean Fuel Standard in its final form could impose additional costs to the Corporation's operations, which may have a material adverse effect on the Corporation's results of operations. The Federal Government has indicated that Spring 2022 is being targeted for publication of the final Clean Fuel Regulations. On December 11, 2020 the Government of Canada released a document entitled A Healthy Environment and a Healthy Economy which outlined 64 new and updated policies and programs to achieve net zero by 2050. This included a proposal to increase the carbon price by $15 per year, starting in 2023, up to $170 per tonne of carbon pollution in 2030. The intent of the price adjustment is to incentivize cleaner fuel choices and discourage pollution-intensive investments.

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

Climate-Related Goals

The Corporation’s mid-term target of a 30% reduction in bitumen GHG emissions and long-term goal of reaching net-zero emissions (which is inherently uncertain due to the potentially long timeframe and certain factors outside of the Corporation’s control, including the application of future technologies) is subject to numerous risks and uncertainties. The Corporation’s actions taken in implementing such a target may expose the Corporation to certain additional and/or heightened financial and operational risks.

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

Cybersecurity

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

Risks Relating to Financing and the Corporation's Indebtedness

Restrictions Contained in Credit Facility, Notes and Debt Service Obligations

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

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

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

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

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

Additional Indebtedness

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

20. DISCLOSURE CONTROLS AND PROCEDURES

The Corporation’s Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”) have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation’s CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. The CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the Corporation and have concluded that the Corporation's disclosure controls and procedures were effective at December 31, 2021 for the foregoing purposes.

21. 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.

22. 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

23. ADVISORY

Forward-Looking Information

This document may contain forward-looking information within the meaning of applicable Canadian securities laws. These statements relate to future events or MEG's future performance. All statements other than statements of historical fact may be forward-looking statements. This forward-looking information is intended to be identified by words such as "anticipate", "believe", "continue", "could", "drive", "expect", "estimate", "focus", "forward", "future", "guidance", "intend", "may", "on track", "outlook", "plan", "position", "potential", "priority", "project", "should", "strategy", "target", "will", "would" or similar expressions and includes statements about future outcomes.

Forward-looking statements are often, but not always, identified by such words. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. In particular, and without limiting the foregoing, this document contains forward looking statements with respect to: the Corporation's business strategy, focus and future plans; the Corporation's marketing strategy and marketing asset optimization strategy; the Corporation's ability to realize production growth over time at the Christina Lake Project while minimizing GHG emissions intensity through cogeneration and the application of its proprietary technologies; the Corporation's commitment to ensuring the health and safety of its personnel and safe and reliable operations of the Christina Lake facility; the ability of the Corporation to deliver on its deleveraging and shareholder return strategy; the Corporation's expectation of initiating its share buyback program in the second quarter of 2022; the Corporation's continued focus on debt reduction; statements regarding incremental well capital required to allow the Corporation to fully utilize the Christina Lake central plant facility's oil processing capacity of approximately 100,000 bbls/d, including the Corporation's expectation that the remaining $50 million of optimization capital will be invested in the first half of 2022; the Corporation's 2022 guidance, including full year 2022 production, non-energy operating costs, general and administrative costs, capital expenditures and total transportation costs; statements with respect to the issuance of a notice for redemption of the remaining balance of the Corporation's Second Lien Notes and the timing and successful completion of the redemption of the remaining balance of the Second Lien Notes; the Corporation's expectation of reaching its near-term debt target of US$1.7 billion in the second quarter of 2022 and thereafter allocating 25% of free cash flow to share buybacks with the remaining cash flow applied to ongoing debt reduction; the Corporation's expectation of reaching its debt-target of US$1.2 billion in the third quarter of 2022 and thereafter allocating 50% of free cash flow to share buybacks while continuing to strengthen its balance sheet; and statements relating to the Corporation's 2030 and 2050 climate-related goals, its participation in the Oil Sands Pathways to Net Zero Alliance and its intention to continue advance ESG and progress on its priority topics; the Corporation's ability to sell excess power into the Alberta electrical grid to displace other power sources that have a higher carbon intensity, thereby reducing the Corporation's overall carbon footprint; the Corporation's expectations regarding 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; and the Corporation's statements regarding its 2022 hedge book.

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, transportation costs, foreign exchange rates and interest rates; the recoverability of the Corporation's reserves and contingent resources; the Corporation's ability to produce and market production of bitumen blend successfully to customers; future growth, results of operations and production levels; future capital and other expenditures; revenues, expenses and cash flow; operating costs; reliability; continued liquidity and runway to sustain operations through a prolonged market downturn; MEG's ability to reduce or increase production to desired levels, including without negative impacts to its assets; anticipated reductions in operating costs as a result of optimization and scalability of certain operations; anticipated sources of funding for operations and capital investments; plans for and results of drilling activity; the regulatory framework governing royalties, land use, taxes and environmental matters, including the timing and level of government production curtailment and federal and provincial climate change policies, in which the Corporation conducts and will conduct its business; the impact of the Corporation's response to the COVID-19 global pandemic,; actions taken by OPEC+ in relation to supply management; 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; actions taken by OPEC+ in relation to supply management; the availability and cost of labour and goods and services required in the Corporation's operations, including inflationary pressures; supply chain issues including transportation delays; the cost and availability of equipment necessary to our operations; 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.

24. 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.

25. QUARTERLY SUMMARIES

	2021				2020			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**177**	54	68	(17)	16	(9)	(80)	(284)
Per share, diluted	**0.57**	0.17	0.22	(0.06)	0.05	(0.03)	(0.26)	(0.95)
Funds flow from operating activities	**260**	212	160	121	81	19	69	69
Adjusted funds flow(1)	**266**	239	166	127	84	26	89	76
Per share, diluted	**0.85**	0.77	0.53	0.41	0.27	0.09	0.29	0.25
Capital expenditures	**106**	84	71	70	40	35	20	54
Working capital	**150**	199	127	8	55	131	173	371
Net debt - C$(1)	**2,401**	2,559	2,661	2,798	2,798	2,981	2,976	3,150
Net debt - US$(1)	**1,897**	2,007	2,145	2,226	2,194	2,237	2,186	2,231
Shareholders' equity	**3,808**	3,628	3,564	3,491	3,506	3,495	3,507	3,593
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**77.19**	70.56	66.07	57.84	42.66	40.93	27.85	46.17
Differential – WTI:WCS – Edmonton (US$/bbl)	**(14.64)**	(13.58)	(11.49)	(12.47)	(9.30)	(9.09)	(11.47)	(20.53)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(16.40)**	(15.13)	(13.11)	(14.22)	(10.56)	(10.48)	(13.44)	(22.78)
AWB – Edmonton (US$/bbl)	**60.79**	55.43	52.96	43.62	32.10	30.45	14.41	23.39
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(6.40)**	(5.57)	(3.92)	(2.52)	(2.83)	(3.20)	(7.29)	(5.74)
AWB – U.S. Gulf Coast (US$/bbl)	**70.79**	64.99	62.15	55.32	39.83	37.73	20.56	40.43
C$ equivalent of 1US$ – average	**1.2600**	1.2602	1.2280	1.2663	1.3031	1.3316	1.3860	1.3445
Natural gas – AECO ($/mcf)	**5.07**	3.92	3.37	3.43	2.88	2.48	2.21	2.26
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**141,280**	127,546	129,474	128,236	136,623	93,479	100,980	142,380
Diluent usage – bbls/d	**(42,386)**	(35,295)	(39,494)	(40,938)	(40,892)	(25,910)	(30,583)	(45,166)
Bitumen sales – bbls/d	**98,894**	92,251	89,980	87,298	95,731	67,569	70,397	97,214
Bitumen production – bbls/d	**100,698**	91,506	91,803	90,842	91,030	71,516	75,687	91,557
Steam-oil ratio (SOR)	**2.42**	2.56	2.39	2.37	2.31	2.36	2.32	2.31
Blend sales(2)	**82.43**	74.54	69.27	61.28	45.75	45.44	20.96	36.46
Diluent expense	**(11.37)**	(9.63)	(9.18)	(8.94)	(7.11)	(5.76)	(10.78)	(17.01)
Bitumen realization(2)	**71.06**	64.91	60.09	52.34	38.64	39.68	10.18	19.45
Transportation & storage expense net of transportation revenue(2)	**(11.39)**	(10.03)	(10.91)	(11.41)	(14.11)	(18.55)	(11.77)	(8.63)
Curtailment	**—**	—	—	—	0.03	—	—	0.18
Royalties	**(3.54)**	(2.67)	(1.71)	(0.85)	(0.23)	(0.21)	(0.05)	(0.63)
Non-energy operating costs(3)	**(4.56)**	(4.46)	(3.84)	(4.05)	(4.70)	(3.96)	(4.09)	(4.57)
Energy operating costs(3)	**(6.22)**	(4.77)	(4.27)	(4.34)	(3.73)	(3.17)	(3.00)	(3.15)
Power revenue	**2.58**	2.06	2.57	3.14	1.45	1.08	0.95	2.21
Realized gain (loss) on commodity risk management	**(10.06)**	(7.73)	(10.63)	(8.80)	1.31	1.71	33.62	11.97
Cash operating netback(2)	**37.87**	37.31	31.30	26.03	18.66	16.58	25.84	16.83
Power sales price (C$/MWh)	**95.22**	82.17	88.40	93.27	46.34	39.03	28.34	69.39
Power sales (MW/h)	**117**	101	113	128	125	78	98	129
Average cost of diluent ($/bbl of diluent)	**108.96**	99.69	90.18	80.34	62.37	60.48	45.76	73.09
Average cost of diluent as a % of WTI	**112 %**	112 %	111 %	110 %	112 %	111 %	119 %	118 %
Depletion and depreciation rate per bbl of production	**13.63**	12.78	12.99	13.15	12.64	13.33	13.55	14.83
General and administrative expense per bbl of production	**1.58**	1.72	1.56	1.77	1.65	1.50	1.29	1.96
COMMON SHARES								
Shares outstanding, end of period (000)	**306,865**	306,773	306,716	303,137	302,681	302,657	302,645	299,547
Common share price ($) - close (end of period)	**11.64**	9.89	8.97	6.53	4.45	2.77	3.77	1.67

(1) *Capital management measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.*
(2) *Non-GAAP financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Supplementary financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.*

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 ranged from a quarterly average of US$27.85/bbl to US$77.19/bbl, and the differential between WTI and the Corporation's AWB at Edmonton, which ranged from a quarterly average of US$10.48/bbl to US$22.78/bbl driven by the impact of COVID-19 on supply/demand fundamentals;
- significant strengthening of benchmark crude oil pricing throughout 2021;
- 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;
- 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.

26. ANNUAL SUMMARIES

	2021	2020	2019	2018[1]	2017[1]	2016[1]	2015[1]
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	283	(357)	(62)	(119)	166	(429)	(1,170)
Per share, diluted	0.91	(1.18)	(0.21)	(0.40)	0.57	(1.90)	(5.21)
Funds flow from operating activities	753	239	741	169	343	(69)	34
Adjusted funds flow[2]	799	275	724	175	371	(63)	49
Per share, diluted	2.57	0.90	2.41	0.58	1.28	(0.28)	0.22
Capital expenditures	331	149	198	622	508	140	314
Working capital	150	55	123	290	313	96	363
Net debt - C$[1]	2,401	2,798	2,917	3,422	4,205	4,897	4,782
Net debt - US$[1]	1,897	2,194	2,250	2,508	3,359	3,647	3,455
Shareholders' equity	3,808	3,506	3,853	3,886	3,964	3,287	3,678
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/bbl)	67.91	39.40	57.03	64.77	50.95	43.33	48.80
Differential – WTI:WCS – Edmonton (US$/bbl)	(13.04)	(12.60)	(12.76)	(26.31)	(11.98)	(13.84)	(13.52)
Differential – WTI:AWB – Edmonton (US$/bbl)	(14.71)	(14.32)	(14.95)	(29.99)	(14.09)	(16.40)	(16.69)
AWB – Edmonton (US$/bbl)	53.20	25.08	42.08	34.78	36.86	26.93	32.11
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	(4.60)	(4.77)	(1.77)	(6.68)	(7.61)	(11.53)	(8.53)
AWB - U.S. Gulf Coast (US$/bbl)	63.31	34.63	55.26	58.09	43.34	31.80	40.27
C$ equivalent of 1US$ – average	1.2536	1.3413	1.3269	1.2962	1.2980	1.3256	1.2788
Natural gas – AECO ($/mcf)	3.95	2.43	1.92	1.62	2.29	2.25	2.71
OPERATIONAL **($/bbl unless specified)**							
Blend sales, net of purchased product – bbls/d	131,659	118,347	134,223	125,368	115,766	116,586	117,132
Diluent usage – bbls/d	(39,521)	(35,626)	(40,637)	(38,317)	(35,766)	(36,159)	(36,167)
Bitumen sales – bbls/d	92,138	82,721	93,586	87,051	80,000	80,427	80,965
Bitumen production – bbls/d	93,733	82,441	93,082	87,731	80,774	81,245	80,025
Steam-oil ratio (SOR)	2.43	2.32	2.22	2.19	2.31	2.29	2.47
Blend sales[3]	72.20	37.65	61.29	53.47	51.39	38.19	42.14
Diluent expense	(9.73)	(10.42)	(8.08)	(16.78)	(9.36)	(10.28)	(11.43)
Bitumen realization[3]	62.47	27.23	53.21	36.69	42.03	27.91	30.71
Transportation & storage expense net of transportation revenue[3]	(10.93)	(12.92)	(10.84)	(8.42)	(6.89)	(6.46)	(4.82)
Curtailment	—	0.06	(0.37)	—	—	—	—
Royalties	(2.25)	(0.31)	(1.30)	(1.20)	(0.77)	(0.29)	(0.70)
Non-energy operating costs[4]	(4.24)	(4.38)	(4.61)	(4.62)	(4.62)	(5.62)	(6.54)
Energy operating costs[4]	(4.94)	(3.29)	(2.38)	(1.98)	(2.98)	(3.01)	(3.84)
Power revenue	2.58	1.49	1.75	1.51	0.76	0.64	0.99
Realized gain (loss) on commodity risk management	(9.32)	11.34	(3.31)	(4.37)	(0.39)	0.08	—
Cash operating netback[3]	33.37	19.22	32.15	17.61	27.14	13.25	15.80
Power sales price (C$/MWh)	90.10	47.81	56.70	47.87	21.49	18.74	27.48
Power sales (MW/h)	115	108	121	114	118	115	121
Average cost of diluent ($/bbl of diluent)	94.88	61.86	79.89	91.60	72.32	61.06	67.72
Average cost of diluent as a % of WTI	111 %	117 %	106 %	109 %	109 %	106 %	109 %
Depletion and depreciation rate per bbl of production	13.15	13.60	20.90	14.12	16.13	16.81	16.00
General and administrative expense per bbl of production	1.65	1.62	1.99	2.58	2.94	3.24	4.06
COMMON SHARES							
Shares outstanding, end of period (000)	306,865	302,681	299,508	296,841	294,104	226,467	224,997
Common share price ($) - close (end of period)	11.64	4.45	7.39	7.71	5.14	9.23	8.02

(1) *The Corporation adopted IFRS 16 Leases, effective January 1, 2019, therefore prior periods have not been restated.*
(2) *Capital management measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Non-GAAP financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.*
(4) *Supplementary financial measure - please refer to section 16 "Non-GAAP and Other Financial Measures" of this MD&A.*

REPORT OF MANAGEMENT

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

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

The Corporation maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Corporation's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that the Corporation's internal controls over financial reporting were effective as of December 31, 2021.

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

PricewaterhouseCoopers LLP, an independent firm of auditors, has been engaged, as approved by a vote of the shareholders at the Corporation's most recent Annual General Meeting, to audit and provide their independent audit opinion on the Corporation's consolidated financial statements as at and for the year ended December 31, 2021. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

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

March 3, 2022

Independent auditor's report

To the Shareholders of MEG Energy Corp.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of MEG Energy Corp. and its subsidiary (together, the Corporation) as at December 31, 2021 and 2020, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited

The Corporation's consolidated financial statements comprise:

- the consolidated balance sheets as at December 31, 2021 and 2020;
- the consolidated statements of earnings (loss) and comprehensive income (loss) for the years then ended;
- the consolidated statements of changes in shareholders' equity for the years then ended;
- the consolidated statements of cash flows for the years then ended; and
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

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

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

Independence

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

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

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2021. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Key audit matter	How our audit addressed the key audit matter
The impact of bitumen reserves on crude oil assets *See note 3 – Significant accounting policies, note 4 – Significant accounting estimates, assumptions, and judgments, and note 7 – Property, plant and equipment to the consolidated financial statements.* The Corporation's crude oil assets net balance was $5,613 million as at December 31, 2021 and the related depletion and depreciation (D&D) expense was $418 million for the year then ended. Crude oil assets consist mainly of field production assets and major facilities and equipment. Field production assets are depleted using the unit-of-production method based on estimates of proved bitumen reserves and major facilities and equipment are depreciated on a unit-of-production basis over the estimated total productive capacity of the asset. Management applies significant judgment in developing the estimates of proved bitumen reserves. These estimates are based on engineering data, estimated future prices, expected future rates of production and the cost and timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Corporation's estimates of proved bitumen reserves statement is reviewed by the Corporation's independent reserve engineers (management's experts). We determined that this is a key audit matter due to the significant judgment by management, including the use of management's experts, when developing the estimates of proved bitumen reserves which	Our approach to addressing the matter involved the following procedures, among others: • Tested how management developed the estimates of proved bitumen reserves and D&D expense, which included the following: – The work of management's experts was used in performing the procedures to evaluate the reasonableness of the estimates of proved bitumen reserves used to determine D&D expense. As a basis for using this work, the competence, capability and objectivity management's experts was evaluated, the work performed were understood and the appropriateness of the work as audit evidence was evaluated. The procedures performed also included evaluation of the methods and assumptions used by management's experts, tests of the data used by management's experts and an evaluation of their findings. Evaluated the reasonableness of assumptions used in developing the underlying estimates, including: o Estimated future prices by comparing those prices with other reputable third party industry forecasts; and o Expected future rates of production, and the cost and timing of future capital expenditures by considering the current and past performance of the Corporation, and whether these assumptions were consistent with evidence obtained in other areas of

Key audit matter	How our audit addressed the key audit matter
led to a high degree of auditor judgment, subjectivity, and effort in performing audit procedures.	the audit. • Tested the data used in the determination of these estimates. • Recalculated the unit-of-production rates used to calculate depletion expense related to field production assets. • Evaluated the reasonableness of the estimated total productive capacity used for facilities and recalculated depreciation expense for major facilities and equipment.

Other information

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

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

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

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

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

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

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

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

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

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

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

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Corporation to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

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

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

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

The engagement partner on the audit resulting in this independent auditor's report is John M. Williamson.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
March 3, 2022

Consolidated Balance Sheet
(Expressed in millions of Canadian dollars)

As at December 31	Note	2021	2020
Assets			
Current assets			
Cash and cash equivalents	21	**$ 361**	$ 114
Trade receivables and other	5	**496**	281
Inventories	6	**157**	96
Risk management	23	**36**	6
		1,050	497
Non-current assets			
Property, plant and equipment	7	**5,878**	5,993
Exploration and evaluation assets	8	**126**	125
Other assets	9	**202**	206
Risk management	23	**41**	21
Deferred income tax asset	12	**296**	382
Total assets		**$ 7,593**	$ 7,224
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 500**	$ 279
Interest payable		**80**	78
Current portion of long-term debt	10	**285**	—
Current portion of provisions and other liabilities	11	**27**	56
Risk management	23	**7**	29
		899	442
Non-current liabilities			
Long-term debt	10	**2,477**	2,912
Provisions and other liabilities	11	**409**	364
Total liabilities		**3,785**	3,718
Shareholders' equity			
Share capital	13	**5,486**	5,460
Contributed surplus		**172**	177
Deficit		**(1,875)**	(2,158)
Accumulated other comprehensive income		**25**	27
Total shareholders' equity		**3,808**	3,506
Total liabilities and shareholders' equity		**$ 7,593**	$ 7,224

Commitments and contingencies (Note 26)
Subsequent events (Note 27)
The accompanying notes are an integral part of these Consolidated Financial Statements.
These Consolidated Financial Statements were approved by the Corporation's Board of Directors on March 3, 2022.

/s/ Derek Evans — Derek Evans, Director

/s/ Robert B. Hodgins — Robert B. Hodgins, Director

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

Year ended December 31	Note	2021	2020
Revenues			
Petroleum revenue, net of royalties	15	**$ 4,222**	$ 2,235
Other revenue	15	**99**	57
Total revenues		**4,321**	2,292
Expenses			
Diluent and transportation expense	16	**1,748**	1,210
Operating expenses		**309**	232
Purchased product		**828**	613
Curtailment		**—**	(2)
Depletion and depreciation	7, 9	**450**	410
Exploration expense	8	**—**	366
General and administrative		**56**	49
Stock-based compensation	14	**26**	(14)
Net finance expense	18	**267**	284
Other expenses	19	**21**	68
Gain on asset dispositions		**(4)**	(6)
Commodity risk management (gain) loss, net	23	**283**	(392)
Foreign exchange (gain) loss, net	17	**(29)**	(49)
Earnings (loss) before income taxes		**366**	(477)
Income tax expense (recovery)	12	**83**	(120)
Net earnings (loss)		**283**	(357)
Other comprehensive income (loss), net of tax			
Items that may be reclassified to profit or loss:			
Foreign currency translation adjustment		**(2)**	(2)
Comprehensive income (loss)		**$ 281**	$ (359)
Net earnings (loss) per common share			
Basic	22	**$ 0.92**	$ (1.18)
Diluted	22	**$ 0.91**	$ (1.18)

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

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

		Share Capital		Contributed Surplus		Deficit		Accumulated Other Comprehensive Income		Total Shareholders' Equity
Balance as at December 31, 2020	**$**	**5,460**	**$**	**177**	**$**	**(2,158)**	**$**	**27**	**$**	**3,506**
Stock-based compensation		**—**		**16**		**—**		**—**		**16**
Stock options exercised		**7**		**(2)**		**—**		**—**		**5**
RSUs vested and released		**19**		**(19)**		**—**		**—**		**—**
Comprehensive income (loss)		**—**		**—**		**283**		**(2)**		**281**
Balance as at December 31, 2021	**$**	**5,486**	**$**	**172**	**$**	**(1,875)**	**$**	**25**	**$**	**3,808**

Balance as at December 31, 2019	$	5,443	$	182	$	(1,801)	$	29	$	3,853
Stock-based compensation		—		12		—		—		12
RSUs vested and released		17		(17)		—		—		—
Comprehensive income (loss)		—		—		(357)		(2)		(359)
Balance as at December 31, 2020	$	5,460	$	177	$	(2,158)	$	27	$	3,506

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

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

Year ended December 31	Note	2021	2020
Cash provided by (used in):			
Operating activities			
Net earnings (loss)		$ **283**	$ (357)
Adjustments for:			
Deferred income tax expense (recovery)	12	**86**	(120)
Depletion and depreciation	7, 9	**450**	410
Exploration expense	8	**—**	366
Stock-based compensation	14	**(33)**	(15)
Unrealized net (gain) loss on foreign exchange	17	**(27)**	(47)
Unrealized net (gain) loss on commodity risk management	23	**(31)**	(49)
Amortization of debt discount and debt issue costs	10	**8**	8
Gain on asset dispositions		**(4)**	(6)
Debt extinguishment expense	18	**18**	12
Other		**8**	9
Decommissioning expenditures	11	**(3)**	(3)
Onerous contracts expense (payments)	11	**(25)**	25
Net change in long-term incentive compensation liability		**23**	6
Funds flow from operating activities		**753**	239
Net change in non-cash working capital items	21	**(63)**	63
Net cash provided by (used in) operating activities		**690**	302
Investing activities			
Capital expenditures	7	**(331)**	(149)
Net proceeds on dispositions	7, 9	**44**	6
Other		**1**	—
Net change in non-cash working capital items	21	**5**	(46)
Net cash provided by (used in) investing activities		**(281)**	(189)
Financing activities			
Issuance of senior unsecured notes	10	**769**	1,581
Repayment and redemption of long-term debt	10	**(889)**	(1,723)
Debt redemption premium and refinancing costs	10	**(23)**	(49)
Issue of shares, net of issue costs		**5**	—
Receipts on leased assets	21	**2**	1
Payments on leased liabilities	21	**(29)**	(26)
Net cash provided by (used in) financing activities		**(165)**	(216)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**3**	11
Change in cash and cash equivalents		**247**	(92)
Cash and cash equivalents, beginning of period		**114**	206
Cash and cash equivalents, end of period		$ **361**	$ **114**

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 410 square miles of mineral leases in the southern Athabasca oil region of Alberta, Canada and is primarily engaged in sustainable *in situ* thermal oil production at its Christina Lake Project.

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

2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board ("IASB"). The consolidated financial statements have been prepared on the historical cost basis, except as detailed in the significant accounting policies disclosed in Note 3. These audited consolidated financial statements were approved by the Corporation's Board of Directors on March 3, 2022.

3. SIGNIFICANT ACCOUNTING POLICIES

a. Principles of consolidation

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

b. Foreign currency translation

i. Functional and presentation currency

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

ii. Transactions and balances

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

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

c. Financial instruments

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

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

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

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

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

i. Financial assets

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

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

ii. Financial liabilities

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

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

d. Cash and cash equivalents

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

e. Trade receivables and other

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

f. Inventories

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

g. Exploration and evaluation assets

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

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

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

h. Property, plant and equipment

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

i. Crude oil

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

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

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

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

ii. Transportation and storage

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

iii. Right-of-use (“ROU”) assets

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

iv. Corporate assets

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

v. Asset dispositions

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

i. Intangible assets

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

j. Leases

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

As Lessee

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

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

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

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

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

As Lessor

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

k. Impairments

i. Financial assets

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

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

ii. Non-financial assets

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

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

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

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

l. Provisions

i. General

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

ii. Decommissioning provision

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

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

iii. Onerous contracts

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

iv. Emissions obligations

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

m. Deferred income taxes

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

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

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

n. Share capital

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

o. Share based payments

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

i. Equity-settled

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

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

ii. Cash-settled

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

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

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

p. Revenue recognition

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

i. Petroleum revenue and royalties

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

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

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

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

ii. Other revenue

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

q. Net earnings (loss) per share

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

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

r. Government grants

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

4. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGMENTS

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

a. Property, plant and equipment

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

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

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

b. Exploration and evaluation assets

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

c. Bitumen reserves

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

d. Decommissioning provision

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

e. Impairments

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

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

f. Stock-based compensation

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

g. Deferred income taxes

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

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

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

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

h. Derivative financial instruments

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

i. Leases

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

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

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

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

5. TRADE RECEIVABLES AND OTHER

As at December 31		**2021**		**2020**
Trade receivables	**$**	**479**	$	261
Deposits and advances		**14**		15
Current portion of deferred financing costs		**—**		3
Current portion of sublease receivable		**3**		2
	$	**496**	$	281

6. INVENTORIES

As at December 31	2021	2020
Bitumen blend	$ 127	$ 81
Diluent	21	7
Material and supplies	9	8
	$ 157	$ 96

During the year ended December 31, 2021, a total of $1.4 billion (2020 - $0.8 billion) in inventory product costs were charged to earnings through diluent and transportation expense.

7. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Right-of-use assets	Corporate assets	Total
Cost					
Balance as at December 31, 2019	$ 9,077	$ 159	$ 263	$ 78	$ 9,577
Additions	151	—	26	—	177
Dispositions	(3)	(71)	—	—	(74)
Lease modification	—	—	7	—	7
Change in decommissioning liabilities	20	—	—	—	20
Balance as at December 31, 2020	$ 9,245	$ 88	$ 296	$ 78	$ 9,707
Additions	331	—	8	1	340
Dispositions	—	(39)	—	—	(39)
Derecognition	—	—	(18)	—	(18)
Change in decommissioning liabilities	35	(2)	—	—	33
Balance as at December 31, 2021	**$ 9,611**	**$ 47**	**$ 286**	**$ 79**	**$ 10,023**
Accumulated depletion and depreciation					
Balance as at December 31, 2019	$ 3,199	$ 102	$ 25	$ 45	$ 3,371
Depletion and depreciation	384	—	23	4	411
Dispositions	(3)	(70)	—	—	(73)
Lease modification	—	—	5	—	5
Balance as at December 31, 2020	$ 3,580	$ 32	$ 53	$ 49	$ 3,714
Depletion and depreciation	418	—	26	5	449
Derecognition	—	—	(18)	—	(18)
Balance as at December 31, 2021	**$ 3,998**	**$ 32**	**$ 61**	**$ 54**	**$ 4,145**
Carrying amounts					
Balance as at December 31, 2020	$ 5,665	$ 56	$ 243	$ 29	$ 5,993
Balance as at December 31, 2021	**$ 5,613**	**$ 15**	**$ 225**	**$ 25**	**$ 5,878**

As at December 31, 2021, property, plant and equipment was assessed for indicators of impairment and none were identified. There were no assets under construction as at December 31, 2021 (assets under construction at December 31, 2020 – $244 million).

During the year ended December 31, 2021, 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.

8. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2019	$	490
Additions		1
Exploration expense		(366)
Balance as at December 31, 2020	**$**	**125**
Change in decommissioning liabilities		**1**
Balance as at December 31, 2021	**$**	**126**

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.

During the first quarter of 2020, the Corporation discontinued exploration and evaluation activities in certain non-core growth properties. Land lease and evaluation costs associated with these assets of $366 million were charged to exploration expense.

9. OTHER ASSETS

As at December 31		2021		2020
Non-current pipeline linefill[a]	**$**	**177**	$	176
Finance sublease receivables		**15**		17
Intangible assets[b]		**5**		7
Deferred financing costs		**—**		3
Prepaid transportation costs[c]		**8**		8
		205		211
Less current portion, included in trade receivables and other		**(3)**		(5)
	$	**202**	$	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.

b. As at December 31, 2021, intangible assets consist of software that is not an integral component of the related computer hardware. Depreciation of $2 million was recognized for the year ended December 31, 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.

10. LONG-TERM DEBT

As at December 31		2021		2020
Second Lien:				
6.50% senior secured second lien notes [(a)] (December 31, 2021 - US$396 million; due 2025; December 31, 2020 - US$496 million)	**$**	**501**	$	633
Unsecured:				
7.125% senior unsecured notes [(b)] (December 31, 2021 - US$1.2 billion; due 2027; December 31, 2020 - US$1.2 billion)		**1,519**		1,531
5.875% senior unsecured notes [(c)] (December 31, 2021 - US$600 million; due 2029; December 31, 2020 - US$nil)		**759**		—
7.0% senior unsecured notes [(c)] (December 31, 2021 - US$nil; December 31, 2020 - US$600 million; due 2024)		**—**		765
		2,779		2,929
Debt redemption premium		**8**		9
Unamortized deferred debt discount and debt issue costs		**(25)**		(26)
	$	**2,762**	$	2,912
Less current portion of 6.50% senior secured second lien notes		**(285)**		—
	$	**2,477**	$	2,912

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2656 (December 31, 2020 – US$1 = C$1.2755).

a. Effective January 27, 2017, the Corporation issued US$750 million in aggregate principal amount of 6.50% senior secured second lien notes, with a maturity of January 15, 2025. Interest is paid semi-annually in January and July. No principal payments are required until January 15, 2025. The Corporation deferred the associated debt issue costs of $18 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

Redemptions on 6.50% senior secured second lien notes due January 2025		US$
Balance as at December 31, 2019	$	596
February 18, 2020 redemption[(i)]		(100)
Balance as at December 31, 2020	$	496
August 23, 2021 redemption[(ii)]		(100)
Balance as at December 31, 2021	$	396
Subsequent redemption on January 18, 2022[(iii)]		(225)
Subsequent redemption on April 4, 2022[(iv)]		(171)
	$	—

(i) Redemption price of 104.875% plus accrued and unpaid interest.
(ii) Redemption price of 103.25% plus accrued and unpaid interest.
(iii) Redemption price of 101.625% plus accrued and unpaid interest. Refer to Note 27 for further details.
(iv) Redemption price of 101.625% plus accrued and unpaid interest. Refer to Note 27 for further details.

The Corporation recognized a cumulative debt redemption premium of $4 million and associated unamortized deferred debt issue costs of $1 million for debt extinguishment expense of $5 million recognized in net finance expense (Note 18) related to the August 23, 2021 redemption.

Subsequent to December 31, 2021, the Corporation repaid US$225 million on January 18, 2022 and announced the repayment of US$171 million to occur on or about April 4, 2022. Both of the 2022 redemptions include prepayment options whereby the Corporation is required to make an estimate at the reporting date of the likelihood of the prepayment option being exercised. Given the January 18, 2022 and April 4, 2022 closing dates, prepayment options were recognized at December 31, 2021 under *IAS 10, Events After the Reporting Period*, as an adjusting subsequent event. For the year ended December 31, 2021, the Corporation recognized a cumulative debt redemption premium of $8 million and associated unamortized deferred debt issue costs of $5 million for debt extinguishment expense of $13 million recognized in net finance expense (Note 18).

b. Effective January 31, 2020, the Corporation successfully closed a private offering of $1.6 billion (US$1.2 billion) in aggregate principal amount of 7.125% senior unsecured notes with a maturity of February 1, 2027. Interest is paid semi-annually in February and August. No principal payments are required until February 1, 2027. The Corporation has deferred the associated debt issue costs of $20 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

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

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

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.

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

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

As at December 31, 2021, the Corporation had $794 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $100 million of unutilized capacity under the $500 million EDC Facility. A letter of credit of $15 million was issued under the revolving credit facility during the first quarter of 2020 and $6 million remains outstanding as at December 31, 2021.

11. PROVISIONS AND OTHER LIABILITIES

As at December 31		2021		2020
Lease liabilities[a]	**$**	**266**	$	286
Decommissioning provision[b]		**135**		96
Onerous contract provision[c]		**—**		25
Long-term incentive compensation liability[d]		**35**		13
Provisions and other liabilities		**436**		420
Less current portion		**(27)**		(56)
Non-current portion	**$**	**409**	$	364

a. Lease liabilities:

As at December 31		2021		2020
Balance, beginning of period	**$**	**286**	$	281
Additions		**8**		19
Modifications		**—**		7
Payments		**(54)**		(47)
Interest expense		**26**		26
Balance, end of period		**266**		286
Less current portion		**(22)**		(28)
Non-current portion	**$**	**244**	$	258

The Corporation's minimum lease payments are as follows:

As at December 31		2021
Within one year	**$**	**46**
Later than one year but not later than five years		**139**
Later than five years		**469**
Minimum lease payments		**654**
Amounts representing finance charges		**(388)**
Net minimum lease payments	**$**	**266**

The Corporation has short-term leases with lease terms of twelve months or less as well as low-value leases. As these lease costs are incurred they are recognized as either general and administrative expense or operating expense depending on their nature. As at December 31, 2021, the present value of these arrangements is $2 million (December 31, 2020 - $1 million), using the Corporation's estimated incremental borrowing rate.

b. Decommissioning provision:

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

As at December 31		2021		2020
Balance, beginning of period	$	96	$	71
Changes in estimated life and estimated future cash flows		5		4
Changes in discount rates		29		16
Liabilities settled		(3)		(3)
Accretion		8		8
Balance, end of period		135		96
Less current portion		(5)		(3)
Non-current portion	$	130	$	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 $799 million (December 31, 2020 – $802 million). As at December 31, 2021, the Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 9.2% (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:

As at December 31, 2020, the Corporation recognized a provision of $25 million related to an onerous marketing contract with a remaining term of one year. The provision represents the present value of the minimum future payments that the Corporation is obligated to make under the non-cancelable onerous contract. Liabilities were settled during the year ended December 31, 2021.

d. Long-term incentive compensation liability:

As at December 31, 2021, the Corporation recognized a liability of $81 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2020 – $23 million). The current portion of $46 million is included within accounts payable and accrued liabilities and $35 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards (December 31, 2020 – $10 million and $13 million). The Corporation entered into equity price risk management contracts to manage its exposure on cash-settled RSUs and PSUs vesting between 2021 and 2023. Refer to Note 23 for further details.

12. INCOME TAX

Year ended December 31		2021		2020
Earnings (loss) before income taxes	**$**	**366**	$	(477)
Statutory income tax rate		**23 %**		24 %
Expected income tax expense (recovery)		**84**		(114)
Add (deduct) the tax effect of:				
Stock-based compensation		**3**		3
Non-taxable loss (gain) on foreign exchange		**(3)**		(4)
Taxable capital loss (gain) not recognized		**(4)**		(4)
Tax benefit of vested RSUs		**(5)**		(1)
Adjustments relating to prior periods		**8**		—
Income tax expense (recovery)	**$**	**83**	$	(120)
Current income tax expense (recovery)	**$**	**(3)**	$	—
Deferred income tax expense (recovery)		**86**		(120)
Income tax expense (recovery)	**$**	**83**	$	(120)

As at December 31, 2021, the Corporation has recognized a deferred tax asset of $296 million (December 31, 2020 - $382 million). The deferred tax asset is reviewed at each balance sheet date to assess whether it is probable that the related tax benefit will be realized. Future taxable income is expected to be sufficient to realize the deferred tax asset.

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

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

		2021		2020
Balance as at January 1	**$**	**382**	$	262
Credited (charged) to earnings		**(86)**		120
Credited (charged) to equity		**—**		—
Balance as at December 31	**$**	**296**	$	382

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

Deferred tax assets		Tax losses		Risk management		Decommissioning provision		Right-of-use assets		Other		Total
Balance as at December 31, 2019	$	1,166	$	18	$	17	$	60	$	45	$	1,306
Credited (charged) to earnings		10		(17)		5		(1)		4		1
Balance as at December 31, 2020		**1,176**		**1**		**22**		**59**		**49**		**1,307**
Credited (charged) to earnings		**(10)**		**(17)**		**9**		**(7)**		**4**		**(21)**
Balance as at December 31, 2021	**$**	**1,166**	**$**	**(16)**	**$**	**31**	**$**	**52**	**$**	**53**	**$**	**1,286**

Deferred tax liabilities	Property, plant and equipment	Commodity risk management	Total
Balance as at December 31, 2019	$ (1,044)	$ —	$ (1,044)
Credited (charged) to earnings	119	—	119
Balance as at December 31, 2020	**(925)**	**—**	**(925)**
Credited (charged) to earnings	**(65)**	**—**	**(65)**
Balance as at December 31, 2021	**$ (990)**	**$ —**	**$ (990)**

As at December 31, 2021, the Corporation had approximately $7.2 billion of available Canadian tax pools including $5.1 billion of non-capital losses (December 31, 2020 - $7.4 billion in available Canadian tax pools including $5.1 billion of non-capital losses). The $5.1 billion of non-capital loss carry forward balances expire as follows:

	2027	2028	2029	2030	2031	Thereafter	Total
Non-capital loss carry forward balances	$ 250	$ 350	$ 500	$ 250	$ 50	$ 3,700	$ 5,100

As at December 31, 2021, the Corporation did not have any incomplete projects (December 31, 2020 - $111 million). As at December 31, 2021, the Corporation had not recognized the tax benefit related to $357 million of realized and unrealized taxable capital foreign exchange losses (December 31, 2020 - $326 million).

13. SHARE CAPITAL

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

Changes in issued common shares are as follows:

	2021		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	**939**	**7**	39	—
Issued upon vesting and release of RSUs and PSUs	**3,245**	**19**	3,134	17
Balance, end of period	**306,865**	**$ 5,486**	302,681	$ 5,460

14. STOCK-BASED COMPENSATION

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

a. Stock-based compensation

Year ended December 31		2021		2020
Cash-settled expense(i)	$	**67**	$	1
Equity-settled expense		**15**		11
Unrealized equity price risk management (gain) loss(ii)		**(48)**		(26)
Realized equity price risk management (gain) loss(ii)		**(8)**		—
Stock-based compensation	$	**26**	$	(14)

(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 23(d) for further details.

b. Cash-settled plans

i. Restricted share units and performance share units:

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

Cash-settled RSUs and PSUs outstanding:

Year ended December 31 (expressed in thousands)	2021	2020
Outstanding, beginning of year	**8,131**	3,254
Granted(i)	**446**	8,328
Vested and released	**(1,724)**	(2,438)
Forfeited	**(108)**	(1,013)
Outstanding, end of year	**6,745**	8,131

(i) Includes units added by PSU performance factors

ii. Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of DSUs to directors of the Corporation. A DSU represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares purchased through a broker. DSUs vest immediately when granted and are redeemed on the earlier of (a) December 15 of the first calendar year starting after the date the holder ceases to be a member of the Corporation, and (b) the fifth business day following each of the redemption dates elected by such holder. As at December 31, 2021, there were 1,172,653 DSUs outstanding (December 31, 2020 – 998,300 DSUs outstanding).

As at December 31, 2021, the Corporation recognized a liability of $82 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2020 – $23 million). The current portion of $45 million is included within accounts payable and accrued liabilities and $37 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards (December 31, 2020 – $10 million and $13 million).

c. Equity-settled plans

i. Stock options outstanding:

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

Year ended December 31	**2021**			**2020**		
	Stock options (thousands)		**Weighted average exercise price**	**Stock options (thousands)**		**Weighted average exercise price**
Outstanding, beginning of year	**4,676**	**$**	**15.21**	6,761	$	18.08
Granted	**—**		**—**	—		—
Exercised	**(914)**		**5.24**	(39)		6.44
Forfeited	**(604)**		**19.87**	(1,158)		20.18
Expired	**(663)**		**37.90**	(888)		30.99
Outstanding, end of year	**2,495**	**$**	**11.70**	4,676	$	15.21

As at December 31, 2021	**Outstanding**				**Vested**			
Range of exercise prices	**Options (thousands)**		**Weighted average exercise price**	**Weighted average remaining life (in years)**	**Options (thousands)**		**Weighted average exercise price**	**Weighted average remaining life (in years)**
$4.53 - $10.00	1,421	$	6.52	3.27	1,239	$	6.80	3.10
$10.01 - $20.00	1,068		18.54	0.45	1,068		18.54	0.45
$20.01 - $21.07	6		21.07	0.17	6		21.07	0.17
	2,495	**$**	**11.70**	**2.06**	**2,313**	**$**	**12.26**	**1.87**

There were no stock options granted during the years ended December 31, 2021 and December 31, 2020.

ii. Restricted share units and performance share units:

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

Equity-settled RSUs and PSUs outstanding:

Year ended December 31 (expressed in thousands)	**2021**	**2020**
Outstanding, beginning of year	**6,531**	6,393
Granted	**3,378**	4,675
Vested and released	**(3,270)**	(3,134)
Forfeited	**(43)**	(1,403)
Outstanding, end of year	**6,596**	6,531

15. REVENUES

Year ended December 31		2021		2020
Sales from:				
Production	**$**	**3,436**	$	1,594
Purchased product[i]		**862**		650
Petroleum revenue	**$**	**4,298**	$	2,244
Royalties		**(76)**		(9)
Petroleum revenue, net of royalties	**$**	**4,222**	$	2,235
Power revenue	**$**	**87**	$	45
Transportation revenue		**12**		12
Other revenue	**$**	**99**	$	57
Total revenues	**$**	**4,321**	$	2,292

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

a. Disaggregation of revenue from contracts with customers

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

	Year ended December 31					
	2021			2020		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	**$ 1,824**	**$ 56**	**$ 1,880**	$ 754	$ 50	$ 804
United States	**1,612**	**806**	**2,418**	840	600	1,440
	$ 3,436	**$ 862**	**$ 4,298**	$ 1,594	$ 650	$ 2,244

For the year ended December 31, 2021, other revenue of $98 million was attributed to Canada and $1 million was attributed to the United States (December 31, 2020 – $57 million attributed to Canada).

a. Revenue-related assets

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

As at December 31		2021		2020
Petroleum revenue	**$**	**455**	$	249
Other revenue		**10**		4
Total revenue-related assets	**$**	**465**	$	253

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

16. DILUENT AND TRANSPORTATION EXPENSE

Year ended December 31	2021	2020
Diluent expense	$ 1,369	$ 807
Transportation and storage expense	379	403
Diluent and transportation expense	$ 1,748	$ 1,210

17. FOREIGN EXCHANGE (GAIN) LOSS, NET

Year ended December 31	2021	2020
Unrealized foreign exchange (gain) loss on:		
Long-term debt	$ (30)	$ (36)
US$ denominated cash and cash equivalents	(4)	(11)
Foreign currency risk management contracts	7	—
Unrealized net (gain) loss on foreign exchange	(27)	(47)
Realized (gain) loss on foreign exchange	(2)	(2)
Foreign exchange (gain) loss, net	$ (29)	$ (49)

C$ equivalent of 1 US$		
Beginning of period	1.2755	1.2965
End of period	1.2656	1.2755

18. NET FINANCE EXPENSE

Year ended December 31	2021	2020
Interest expense on long-term debt	$ 217	$ 241
Interest expense on lease liabilities	26	26
Interest income	(2)	(3)
Net interest expense	241	264
Accretion on provisions	8	8
Debt extinguishment expense[(a)(b)]	18	12
Net finance expense	$ 267	$ 284

a. For the year ended December 31, 2021, debt extinguishment expense was recognized in association with debt redemptions up to and including April 4, 2022. The expense is comprised of debt redemption premiums of $12 million and unamortized deferred debt issue costs of $6 million. Refer to Note 10 for further details.

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

19. OTHER EXPENSES

Year ended December 31		2021		2020
Settlement expense(i)	$	21	$	—
Contract cancellation(ii)		—		33
Onerous contract expense(iii)		—		25
Severance and restructuring		—		10
Other expenses	$	21	$	68

(i) During the year ended December 31, 2021, the Corporation settled a 2014 litigation matter relating to legacy issues involving a unit train transloading facility in Alberta. The Corporation paid the sum of $21 million and the claim was discontinued.

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

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

20. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the years ended December 31, 2021 and 2020, other than compensation of key management personnel. The Corporation considers directors and officers of the Corporation as key management personnel.

Year ended December 31		2021		2020
Share-based compensation	$	36	$	6
Salaries and short-term employee benefits		5		5
	$	41	$	11

The increase in share-based compensation to key management personnel in 2021 is mainly due to the increase in the Corporation's share price and its impact on the value of the share-based awards.

21. SUPPLEMENTAL CASH FLOW DISCLOSURES

Year ended December 31		2021		2020
Cash provided by (used in):				
Trade receivables and other	$	(220)	$	102
Inventories		(62)		13
Accounts payable and accrued liabilities		223		(101)
Interest payable		1		3
	$	(58)	$	17
Changes in non-cash working capital relating to:				
Operating	$	(63)	$	63
Investing		5		(46)
	$	(58)	$	17
Cash and cash equivalents:(a)				
Cash	$	361	$	114
Cash equivalents		—		—
	$	361	$	114
Cash interest paid	$	190	$	213

a. As at December 31, 2021, $6 million of the Corporation's total cash and cash equivalents balance was held in

U.S. dollars (December 31, 2020 – $104 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$1.2656 (December 31, 2020 – US$1=C$1.2755).

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	(2)	—	—
Payments on leased liabilities	—	(29)	—
Issuance of senior unsecured notes	—	—	769
Repayment and redemption of long-term debt	—	—	(889)
Debt redemption premium and refinancing costs	—	—	(23)
Other cash and non-cash changes:			
Lease liabilities settled	—	(25)	—
Lease liabilities incurred	—	8	—
Interest expense on lease liabilities	—	26	—
Unrealized (gain) loss on foreign exchange	—	—	(30)
Debt redemption premium	—	—	13
Amortization of deferred debt discount and debt issue costs	—	—	10
Balance as at December 31, 2021	**$ 15**	**$ 266**	**$ 2,762**

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

22. NET EARNINGS (LOSS) PER COMMON SHARE

Year ended December 31	2021	2020
Net earnings (loss)	**$ 283**	$ (357)
Weighted average common shares outstanding (millions)[(a)]	**306**	302
Dilutive effect of stock options, RSUs and PSUs (millions)[(b)]	**5**	—
Weighted average common shares outstanding – diluted (millions)	**311**	302
Net earnings (loss) per share, basic	**$ 0.92**	$ (1.18)
Net earnings (loss) per share, diluted	**$ 0.91**	$ (1.18)

a. Weighted average common shares outstanding for the year ended December 31, 2021 include nil PSUs vested but not yet released (year ended December 31, 2020 - 360,543 PSUs).

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

23. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

a. Fair values:

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

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

As at December 31	**2021**		**2020**	
	Carrying amount	**Fair value**	**Carrying amount**	**Fair value**
Recurring measurements:				
Financial assets				
Commodity risk management contracts	**$ 3**	**$ 3**	$ 1	$ 1
Equity price risk management contracts	**$ 74**	**$ 74**	$ 26	$ 26
Financial liabilities				
Long-term debt (Note 10)	**$ 2,779**	**$ 2,888**	$ 2,929	$ 3,019
Commodity risk management contracts	**$ —**	**$ —**	$ 29	$ 29
Foreign currency risk management contracts	**$ 7**	**$ 7**	$ —	$ —

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker. The fair value was determined based on estimates as at December 31, 2021 and is expected to fluctuate given the volatility in the debt and commodity price markets.

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

b. Risk management:

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

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

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

As at December 31	2021			2020		
	Asset	Liability	Net	Asset	Liability	Net
Gross amount	**$ 77**	**$ (7)**	**$ 70**	$ 27	$ (62)	$ (35)
Amount offset	**—**	**—**	**—**	—	33	33
Net amount	**$ 77**	**$ (7)**	**$ 70**	$ 27	$ (29)	$ (2)
Current portion	**$ 36**	**$ (7)**	**$ 29**	$ 6	$ (29)	$ (23)
Non-current portion	**41**	**—**	**41**	21	—	21
Net amount	**$ 77**	**$ (7)**	**$ 70**	$ 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 December 31:

As at December 31	2021	2020
Fair value of contracts, beginning of year	**$ (2)**	$ (77)
(Gain) loss on fair value of contracts realized	**306**	(343)
Change in fair value of contracts[i]	**(234)**	418
Fair value of contracts, end of period	**$ 70**	$ (2)

(i) As at December 31, 2021 and 2020 this amount includes the change in the fair value of the equity price risk management contracts of $48 million and $26 million, respectively.

c. Commodity risk management

The Corporation had the following financial commodity risk management contracts relating to condensate purchases and natural gas purchases outstanding as at December 31, 2021:

As at December 31, 2021			
Condensate Purchase Contract	**Volumes (bbls/d)[i]**	**Term**	**Average Price (US$/bbl)[i]**
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	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.

The Corporation did not enter into physical and financial commodity risk management contracts between December 31, 2021 and March 3, 2022.

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

Year ended December 31	2021	2020
Realized loss (gain) on commodity risk management	**$ 314**	$ (343)
Unrealized loss (gain) on commodity risk management	**(31)**	(49)
Commodity risk management (gain) loss, net	**$ 283**	$ (392)

The following table summarizes the sensitivity of the earnings (loss) before income tax impact of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place as at December 31, 2021:

Commodity	Sensitivity Range	Increase	Decrease
Condensate purchase price	± 5% in condensate price as a percentage of WTI	$ —	$ —
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	$ 2	$ (2)

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.

($millions)	2021	2020
Unrealized equity price risk management (gain) loss	$ (48)	$ (26)
Realized equity price risk management (gain) loss	(8)	—
Equity price risk management (gain) loss	$ (56)	$ (26)

The sensitivity of the earnings (loss) before income tax impact of changes in the Corporation's share price on equity price risk management contracts in place at December 31, 2021 is as follows:

	Sensitivity Range	Increase	Decrease
Equity price risk management contracts	± 10% applied to Corporation's share price	$ 9	$ (9)

e. Foreign currency risk management

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the fair value or future cash flows of the Corporation's financial assets or liabilities. The Corporation has U.S. dollar denominated long-term debt as described in Note 10. As at December 31, 2021, a $0.01 change in the U.S. dollar to Canadian dollar exchange rate would have resulted in a change to the carrying value of long-term debt and a corresponding change to earnings (loss) before income tax of C$22 million (December 31, 2020 - C$23 million).

The Corporation occasionally enters into short-term financial foreign currency risk management contracts to manage foreign currency risk on certain cash and cash equivalents. As at December 31, 2021, the Corporation had outstanding financial foreign currency risk management contracts on $334 million of cash and cash equivalents which fixed the exchange rate at 1.2897 Canadian dollar equivalent of $1 U.S. dollar.

f. Credit risk management:

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward looking information to determine the appropriate loss allowance provisions. Credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to each counterparty's credit quality. A substantial portion of accounts receivable are with investment grade customers in the energy industry and are subject to normal industry credit risk. The

Corporation has experienced no material loss in relation to trade receivables. As at December 31, 2021, the Corporation’s estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $493 million. All amounts receivable from commodity risk management activities are due from large Canadian banks with strong investment grade credit ratings. Counterparty default risk associated with the Corporation’s commodity risk management activities is also partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements.

The Corporation’s cash balances are currently used to repay debt and fund sustaining capital. As a result, the primary objectives of the investment portfolio are low risk capital preservation and high liquidity. The cash balances are held in high interest savings accounts or are invested in high grade, liquid, short-term instruments such as bankers’ acceptances, commercial paper, money market deposits or similar instruments. The cash and cash equivalents balance at December 31, 2021 was $361 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 $361 million.

g. 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.

After the January 2022 and April 2022 debt redemptions disclosed in both Notes 10 and 27, the Corporation's earliest maturing long-term debt will be approximately five years out, represented by US$1.2 billion of senior unsecured notes due February 2027. 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.

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

As at December 31, 2021	**Total**	**Less than 1 year**	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Long-term debt	$ 2,779	$ 501	$ —	$ —	$ 2,278
Interest on long-term debt	$ 881	161	306	306	108
Commodity risk management contracts	$ 7	7	—	—	—
Accounts payable and accrued liabilities	$ 500	500	—	—	—
	$ 4,167	$ 1,169	$ 306	$ 306	$ 2,386

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

24. GEOGRAPHICAL DISCLOSURE

As at December 31, 2021, the Corporation had non-current assets related to operations in the United States of $105 million (December 31, 2020 – $106 million). For the year ended December 31, 2021, petroleum revenue related to operations in the United States was $2.4 billion (year ended December 31, 2020 – $1.4 billion).

25. 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.

On August 23, 2021, the Corporation redeemed US$100 million (approximately C$125 million) of the Corporation's 6.5% senior secured second lien notes due January 2025 at a redemption price of 103.25% plus accrued and unpaid interest.

Subsequent to December 31, 2021, on January 18, 2022, the Corporation redeemed US$225 million (approximately C$285 million) of the 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625%, plus accrued and unpaid interest to, but not including, the redemption date. The Corporation also announced, on March 3, 2022, that it had issued a notice to redeem the remaining US$171 million (approximately C$216 million) of the 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625%, plus accrued and unpaid interest to, but not including, the redemption date. This announced redemption is expected to be completed on or about April 4, 2022.

The Corporation's earliest maturity date on outstanding debt as at December 31, 2021 is January 2025. As at December 31, 2021, the Corporation had $794 million of unutilized capacity under the $800 million revolving credit facility and had $100 million of unutilized capacity under the $500 million letter of credit facility. A letter of credit of $15 million was issued under the revolving credit facility during the first quarter of 2020 and $6 million remains outstanding as at December 31, 2021.

The following table summarizes the Corporation's net debt:

As at December 31	Note	2021	2020
Long-term debt	10	**$ 2,477**	$ 2,912
Current portion of long-term debt	10	**285**	—
Cash and cash equivalents		**(361)**	(114)
Net debt		**$ 2,401**	$ 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 operating activities, adjusted funds flow and free cash flow :

	Three months ended December 31		Year ended December 31	
($millions)	**2021**	**2020**	**2021**	**2020**
Funds flow from operating activities	**$ 260**	$ 81	**$ 753**	$ 239
Adjustments:				
Payments on onerous contract	**6**	—	**25**	—
Settlement expense[(i)]	**—**	—	**21**	—
Contract cancellation	**—**	—	**—**	33
Net change in other liabilities[(ii)]	**—**	3		3
Adjusted funds flow	**266**	84	**799**	275
Capital expenditures	**(106)**	(38)	**(331)**	(149)
Free cash flow	**$ 160**	$ 46	**$ 468**	$ 126

(i) During the year ended December 31, 2021, the Corporation reached an agreement to settle the litigation matter commenced in 2014 relating to legacy issues involving a unit train transloading facility in Alberta. Under the agreement, the Corporation paid the sum of $21 million in full and final settlement of the claim and the claim has been discontinued.

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

Management utilizes funds flow from operating activities, adjusted funds flow and free cash flow as a measure to analyze operating performance and cash flow generating ability. Funds flow from operating activities, adjusted funds flow and free cash flow impacts the level and extent of debt repayment, funding for capital expenditures and returning capital to shareholders. By excluding non-recurring items from cash flows, the funds flow from operating activities 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. Free cash flow provides a meaningful metric to assist management and investors in analyzing corporate performance as a measure of financial liquidity and the capacity of the business to repay debt. Funds flow from operating activities, adjusted funds flow and free cash flow are not intended to represent net cash provided by (used in) operating activities.

Net debt, adjusted funds flow and free cash flow are not standardized measures and may not be comparable with the calculation of similar measures by other companies.

26. COMMITMENTS AND CONTINGENCIES

a. Commitments

The Corporation’s commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at December 31, 2021:

		2022		2023		2024		2025		2026		Thereafter		Total
Transportation and storage[(i)]	$	404	$	440	$	440	$	415	$	377	$	5,302	$	7,378
Diluent purchases		152		17		—		—		—		—		169
Other operating commitments		16		16		14		13		13		23		95
Variable office lease costs		4		4		4		5		5		22		44
Capital commitments		16		—		—		—		—		—		16
Commitments	**$**	**592**	**$**	**477**	**$**	**458**	**$**	**433**	**$**	**395**	**$**	**5,347**	**$**	**7,702**

(i) This represents transportation and storage commitments from 2022 to 2048, including the Access Pipeline TSA, and pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet (Note 11(a)).

b. Contingencies

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

The Corporation was the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility in Alberta. During the third quarter of 2021, the Corporation reached an agreement to settle this litigation matter. Under the agreement, the Corporation paid the sum of $21 million in full and final settlement of the claim and the claim has been discontinued.

27. SUBSEQUENT EVENTS

Debt Redemptions

On November 29, 2021, the Corporation announced that it had issued a notice to redeem US$225 million (approximately C$285 million) of the 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625%, plus accrued and unpaid interest to, but not including, the redemption date. The redemption was completed on January 18, 2022.

On March 3, 2022, the Corporation announced that it had issued a notice to redeem the remaining outstanding balance of US$171 million (approximately C$216 million) of the 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625%, plus accrued and unpaid interest to, but not including, the redemption date. The redemption is expected to be completed on or about April 4, 2022.

These redemptions include prepayment options 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 these announced redemptions, an expense was recognized as at December 31, 2021 to reflect the known likelihood of the prepayment option, with the expense reflecting the 101.625% prepayment redemption price. For the year ended December 31, 2021, the Corporation recognized a debt redemption premium of $8 million and an additional $5 million expense reflecting the remaining unamortized deferred debt issue costs for a total debt extinguishment expense of $13 million.

Normal Course Issuer Bid

The Corporation's Board of Directors approved on March 3, 2022 the filing of an application with the Toronto Stock Exchange ("TSX") for a normal course issuer bid ("NCIB") which, once approved by the TSX, will allow the Corporation to initiate a share buyback program to buy back over the next twelve months up to 10% of the Corporation's public float, as defined by the TSX, up to a maximum of approximately 27.2 million common shares of the Corporation.

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