MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three and six months ended *June 30, 2023 was approved by the Corporation's Audit Committee on July 27, 2023. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the* three and six months ended *June 30, 2023, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2022, the 2022 annual MD&A and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in millions of Canadian dollars, except where otherwise indicated.*

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

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 14 "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*
    - *Net transportation and storage expense*
    - *Bitumen realization after net transportation and storage expense*
    - *Operating expenses net of power revenue*
    - *Energy operating costs net of power revenue*
    - *Effective royalty rate*
    - *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*

MD&A - Table of Contents

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 is a member of the Pathways Alliance, a group of Canada's largest oil sands producers working together to address climate change and achieve the goal of net zero emissions[1] by 2050.

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 evaluated, as at December 31, 2022, contained approximately 1.94 billion barrels of gross proved plus probable ("2P") bitumen reserves at the Christina Lake Project. For information regarding MEG's estimated reserves contained in the report prepared by GLJ, please refer to the Corporation's most recently filed AIF, which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR+ website at www.sedarplus.ca.

The Christina Lake Project, which contains all the Corporation's 2P reserves has regulatory approval in place for 210,000 bbls/d of production. At a steam-oil ratio ("SOR") of 2.2, MEG has developed oil processing capacity of approximately 110,000 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 103,700 bbls/d, MEG has a 2P reserve life index of greater than 50 years.

The Corporation has been able to realize production growth over time at the Christina Lake Project while minimizing SOR and associated greenhouse gas ("GHG") emissions intensity through the application of proprietary technologies, including MEG's proprietary reservoir technology, eMSAGP, which 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 GHG emissions intensity more than 15% 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. In addition, in 2022, as part of a broader development strategy, MEG introduced enhanced completion designs and optimized inter-well spacing all focused on reducing SOR. MEG achieved an average SOR of 2.36 in 2022 compared to the *in situ* industry volume weighted average of 3.0.[2]

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 ("TMX") which, when in service, will provide MEG with 20,000 bbls/d of contracted AWB transportation capacity to Canada's West Coast. MEG has proprietary and contracted oil storage capacity of approximately 2.1 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,

[1] Scope 1 and scope 2 emissions
[2] Annual 2022 data as per the Alberta Energy Regulator ST53.

including the Enterprise TEPPCO and Enbridge Southern Lights import pipelines for access to Mont Belvieu supply. This system provides a range of diluent supply alternatives and helps to mitigate diluent supply and price risk.

In the Edmonton area, MEG has approximately 1.1 million barrels of 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 pipeline capacity, storage capacity and marine export capacity in the USGC 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 capacity on the Bayou Bridge pipeline to access USGC refineries and export facilities beyond Texas.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The Corporation generated $129 million of free cash flow during the second quarter of 2023 compared to $374 million in the same quarter of 2022. Free cash flow and available cash were used to purchase US$40 million (approximately $54 million) of outstanding 7.125% senior unsecured notes and return $66 million to MEG shareholders through the repurchase and cancellation of 3.1 million shares.

Funds flow from operating activities and adjusted funds flow were both $278 million in the second quarter of 2023 compared to $412 million and $478 million in the same quarter of 2022, respectively. These decreases reflect a 48% reduction in cash operating netback per barrel due to a lower average WTI price, a wider WTI:AWB differential and higher net transportation and storage expenses, partially offset by lower operating expenses net of power revenue. The lower cash operating netback, partially offset by an unrealized foreign exchange gain, lower interest expense and reduced income tax expense resulted in a net earnings decline to $136 million in the second quarter of 2023 from $225 million in the second quarter of 2022.

Average bitumen production in the second quarter of 2023 rose to 85,974 barrels per day from 67,256 barrels per day in the same period of 2022. Major planned turnaround activities at the Christina Lake Facility impacted both periods, but during the second quarter of 2022 the Corporation also experienced an unplanned electrical event following the turnaround which resulted in a slower than forecast production ramp-up. The resulting higher sales volumes in the second quarter of 2023 partially offset the lower cash operating netback per barrel.

Capital expenditures in the second quarter of 2023 rose by $45 million to $149 million, compared to the same period in 2022, reflecting increased sustaining and maintenance costs resulting from increased scope and timing of field development and maintenance activities. Turnarounds at the Christina Lake facility during both periods were successfully completed on time. Increased turnaround costs in the second quarter of 2023 reflect a larger planned turnaround scope, found work, inflationary pressures on labour costs and ongoing supply chain challenges.

As at June 30, 2023, cash and cash equivalents was $66 million. The Corporation exited the quarter with total debt and net debt of approximately $1,382 million and $1,316 million (US$994 million), respectively.

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

	Six months ended June 30		2023		2022				2021	
($millions, except as indicated)	**2023**	**2022**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Bitumen production - bbls/d	**96,349**	84,099	**85,974**	106,840	110,805	101,983	67,256	101,128	100,698	91,506
Steam-oil ratio	**2.25**	2.44	**2.25**	2.25	2.22	2.39	2.46	2.43	2.42	2.56
Bitumen sales - bbls/d	**94,942**	86,564	**83,531**	106,480	113,582	95,759	73,091	100,186	98,894	92,251
Bitumen realization after net transportation and storage expense[1] - $/bbl	**49.69**	108.07	**57.64**	43.40	54.75	74.75	103.29	84.31	59.67	54.88
Operating expenses - $/bbl	**10.01**	13.46	**9.58**	10.34	11.05	10.61	16.05	11.54	10.78	9.23
Operating expenses net of power revenue[1] - $/bbl	**6.35**	10.68	**6.63**	6.13	5.83	5.45	12.97	8.98	8.20	7.17
Non-energy operating costs[2] - $/bbl	**5.17**	5.13	**5.66**	4.77	4.34	4.49	5.65	4.74	4.56	4.46
Cash operating netback[1] - $/bbl	**37.89**	75.10	**42.38**	34.32	43.89	62.63	81.75	70.21	37.87	37.31
General & administrative expense - $/bbl of bitumen production volumes	**1.90**	1.92	**1.85**	1.94	1.62	1.72	2.37	1.61	1.58	1.72
Funds flow from operating activities	**626**	999	**278**	348	383	501	412	587	260	212
Per share, diluted	**2.15**	3.18	**0.96**	1.19	1.28	1.63	1.31	1.87	0.83	0.68
Adjusted funds flow[3]	**552**	1,038	**278**	274	401	496	478	559	274	243
Per share, diluted[3]	**1.90**	3.30	**0.96**	0.94	1.34	1.61	1.52	1.78	0.88	0.78
Free cash flow[3]	**290**	846	**129**	161	295	418	374	471	168	159
Revenues	**2,771**	3,102	**1,291**	1,480	1,445	1,571	1,571	1,531	1,307	1,091
Net earnings (loss)	**217**	587	**136**	81	159	156	225	362	177	54
Per share, diluted	**0.74**	1.87	**0.47**	0.28	0.53	0.51	0.72	1.15	0.57	0.17
Capital expenditures	**262**	192	**149**	113	106	78	104	88	106	84
Long-term debt, including current portion	**1,382**	2,026	**1,382**	1,466	1,581	1,803	2,026	2,440	2,762	2,769
Net debt[3] - C$	**1,316**	1,782	**1,316**	1,381	1,389	1,634	1,782	2,150	2,401	2,559
Net debt[3] - US$	**994**	1,384	**994**	1,020	1,026	1,193	1,384	1,722	1,897	2,007

(1) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Supplementary financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.
(3) Capital management measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

3. SUSTAINABILITY AND PATHWAYS UPDATE

MEG, along with its Pathways Alliance ("Alliance") peers, continues to progress pre-work on the proposed foundational carbon capture and storage ("CCS") project, which will transport CO2 via pipeline from multiple oil sands facilities to be stored safely and permanently underground in the Cold Lake region of Alberta.

During the second quarter of 2023, the Alliance continued to evaluate the Pathways Alliance proposed storage hub and is working to obtain a carbon sequestration agreement from the Government of Alberta by year-end 2023 to allow for regulatory submissions for the carbon storage hub. In addition, the Alliance continued to advance engineering and field work related to the proposed CCS project in order to support a regulatory application anticipated in the fourth quarter of 2023 for the CCS network. Formal consultation with about 25 Indigenous groups along the proposed CO2 transportation and storage network corridor has commenced and follows early engagement with these groups over the last two years.

The Alliance continues to work collaboratively with both the federal and Alberta governments on the necessary policy and co-financing frameworks required to move the project forward. During the second quarter of 2023, the Government of Alberta released its Emissions Reduction and Energy Development Plan with the goal of reducing emissions and achieving net zero, while ensuring industry can compete globally, attract investment and continue to provide economic growth and prosperity for Albertans and Canadians. The Government of Alberta recognized that a coordinated approach with the federal government and industry is needed to compete with the United States, Europe and others for investment in wide scale carbon capture, utilization and storage deployment, essential to achieve emissions reduction goals. The Alberta and federal governments are also in discussions relating to the formation of a bilateral working group to incentivize carbon capture and storage and other emissions-reduction technologies.

For further details on the Corporation's approach to ESG matters, please refer to the Corporation's 2021 ESG Report and its 2022 ESG Performance Data Supplement available in the "Sustainability" section of the Corporation's website at www.megenergy.com and the most recently filed AIF on www.sedarplus.ca.

4. NET EARNINGS

	Three months ended June 30		Six months ended June 30	
($millions, except per share amounts)	**2023**	**2022**	**2023**	**2022**
Net earnings	**$ 136**	$ 225	**$ 217**	$ 587
Per share, diluted	**$ 0.47**	$ 0.72	**$ 0.74**	$ 1.87

Net earnings declined to $136 million and $217 million during the three and six months ended June 30, 2023 compared to $225 million and $587 million during the same periods of 2022, respectively, mainly reflecting a lower cash operating netback and higher depletion and depreciation expense, partially offset by an unrealized foreign exchange gain and reduced income tax expense.

5. REVENUES

Revenues are comprised of petroleum revenue, net of royalties, including sales of third-party products related to marketing asset optimization, and power and transportation revenue.

	Three months ended June 30		Six months ended June 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Sales from:				
Production	**$ 942**	$ 1,224	**$ 1,985**	$ 2,617
Purchased product(1)	**383**	383	**810**	544
Petroleum revenue	**$ 1,325**	$ 1,607	**$ 2,795**	$ 3,161
Royalties	**(58)**	(58)	**(89)**	(105)
Petroleum revenue, net of royalties	**$ 1,267**	$ 1,549	**$ 2,706**	$ 3,056
Power revenue	**$ 23**	$ 21	**$ 63**	$ 44
Transportation revenue	**1**	1	**2**	2
Power and transportation revenue	**$ 24**	$ 22	**$ 65**	$ 46
Revenues	**$ 1,291**	$ 1,571	**$ 2,771**	$ 3,102

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

During the three and six months ended June 30, 2023, petroleum revenue, net of royalties decreased to $1.3 billion and $2.7 billion, respectively, from $1.5 billion and $3.1 billion in the same periods of 2022. The decreases primarily reflect lower sales from production driven by a weaker average WTI benchmark price and wider WTI:AWB differentials partially offset by increased blend sales volumes and a weaker Canadian dollar relative to the U.S. dollar.

Revenues include the sale of third-party products related to marketing asset optimization activities. The associated purchase of third-party products is recognized within "Purchased product" expense. These transactions are mainly undertaken to recover fixed costs related to transportation and storage contracts. The Corporation does not engage in speculative trading. The purchase and sale of third-party products to facilitate marketing 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 physical transactions or through financial price risk management.

6. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended June 30		Six months ended June 30	
	2023	**2022**	**2023**	**2022**
Bitumen production – bbls/d	**85,974**	67,256	**96,349**	84,099
Steam-oil ratio (SOR)	**2.25**	2.46	**2.25**	2.44

Bitumen Production

Bitumen production increased approximately 28% and 15% in the three and six months ended June 30, 2023, compared to the same periods of 2022, reflecting the Corporation's continued focus on optimized well spacing, enhanced completion designs, a capital efficient well redevelopment program and targeted facility enhancements. Production for the second quarters of both 2023 and 2022 was impacted by major planned turnaround activities at the Christina Lake Facility. During the second quarter of 2022, the Corporation also experienced an unplanned electrical event following the turnaround which resulted in a slower than forecast production ramp-up.

Steam-Oil Ratio

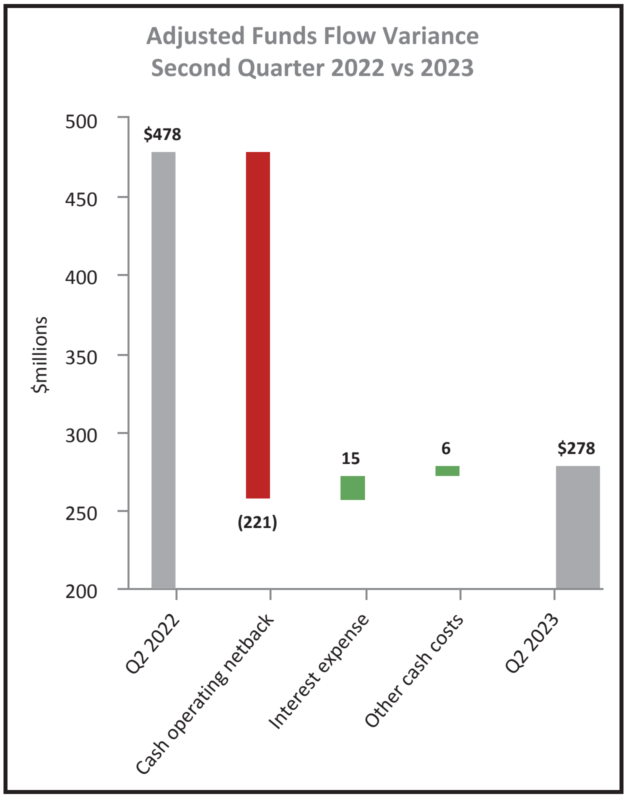
The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is SOR, which is an efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR decreased approximately 9% and 8% during the three and six months ended June 30, 2023, compared to the same periods of 2022, due to the deployment of enhanced completion designs, redevelopment plans and an emphasis on steam allocation to the high-quality resource.

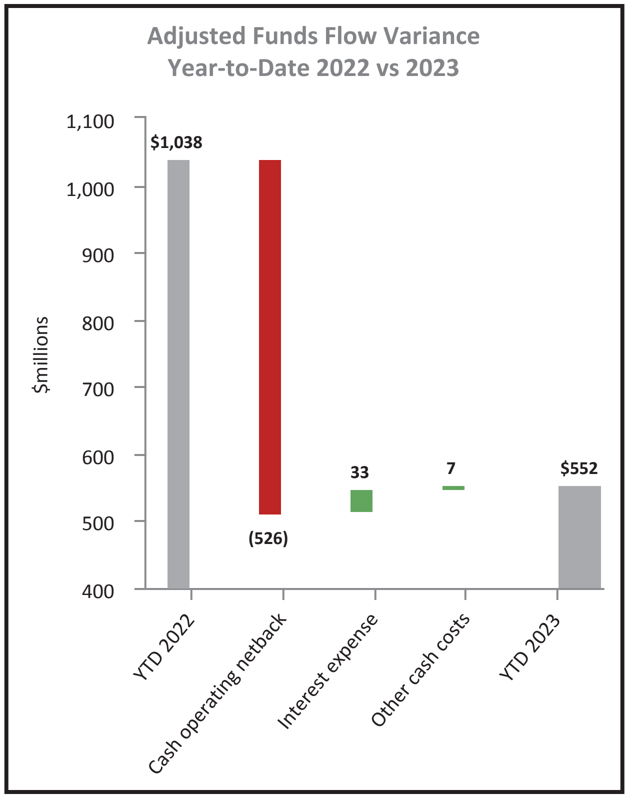
Funds Flow from Operating Activities and Adjusted Funds Flow

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 operations. 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 establishes a clearer link between cash flows and the cash operating netback.

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

	Three months ended June 30		Six months ended June 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Funds flow from operating activities	**$ 278**	$ 412	**$ 626**	$ 999
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management	**—**	66	**13**	85
Realized equity price risk management gain	**—**	—	**(87)**	(46)
Adjusted funds flow	**$ 278**	$ 478	**$ 552**	$ 1,038
Per share, diluted	**$ 0.96**	$ 1.52	**$ 1.90**	$ 3.30





Funds flow from operating activities and adjusted funds flow decreased in the three and six months ended June 30, 2023, compared to the same periods of 2022, driven mainly by a lower cash operating netback partially offset by lower interest expense due to reduced debt levels. Funds flow from operating activities in the six months ended June 30, 2023, compared to the same period of 2022, was also impacted by the expense associated with cash-settled stock-based compensation units and the related realized equity price risk management gain.

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 volumes.

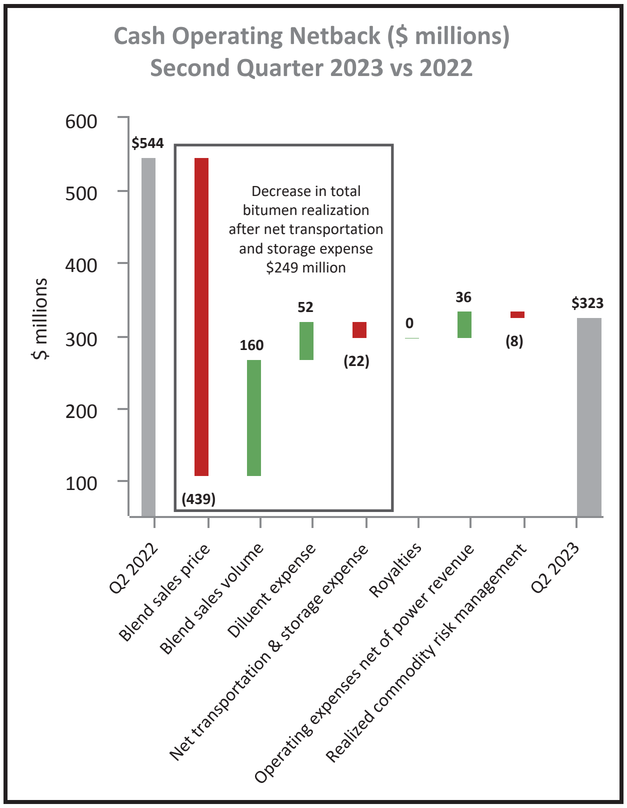
	Three months ended June 30				Six months ended June 30			
	2023		2022		2023		2022	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Sales from production	**$ 942**		$ 1,224		**$ 1,985**		$ 2,617	
Sales from purchased product[1]	**383**		383		**810**		544	
Petroleum revenue	**$ 1,325**		$ 1,607		**$ 2,795**		$ 3,161	
Purchased product[1]	**(373)**		(376)		**(787)**		(536)	
Blend sales[2][3]	**$ 952**	**$ 87.81**	$ 1,231	$ 128.20	**$ 2,008**	**$ 81.22**	$ 2,625	$ 115.23
Diluent expense	**(363)**	**(10.27)**	(415)	(5.51)	**(861)**	**(14.48)**	(932)	(7.16)
Bitumen realization[3]	**$ 589**	**$ 77.54**	$ 816	$ 122.69	**$ 1,147**	**$ 66.74**	$ 1,693	$ 108.07
Net transportation and storage expense[3][4]	**(151)**	**(19.90)**	(129)	(19.40)	**(293)**	**(17.05)**	(246)	(15.70)
Bitumen realization after net transportation and storage expense[3]	**438**	**57.64**	687	103.29	**854**	**49.69**	1,447	92.37
Royalties	**(58)**	**(7.69)**	(58)	(8.67)	**(89)**	**(5.17)**	(105)	(6.70)
Operating expenses net of power revenue[3]	**(50)**	**(6.63)**	(86)	(12.97)	**(109)**	**(6.35)**	(167)	(10.68)
Realized gain (loss) on commodity risk management	**(7)**	**(0.94)**	1	0.10	**(5)**	**(0.28)**	2	0.11
Cash operating netback[3]	**$ 323**	**$ 42.38**	$ 544	$ 81.75	**$ 651**	**$ 37.89**	$ 1,177	$ 75.10
Bitumen sales volumes - bbls/d		**83,531**		73,091		**94,942**		86,564

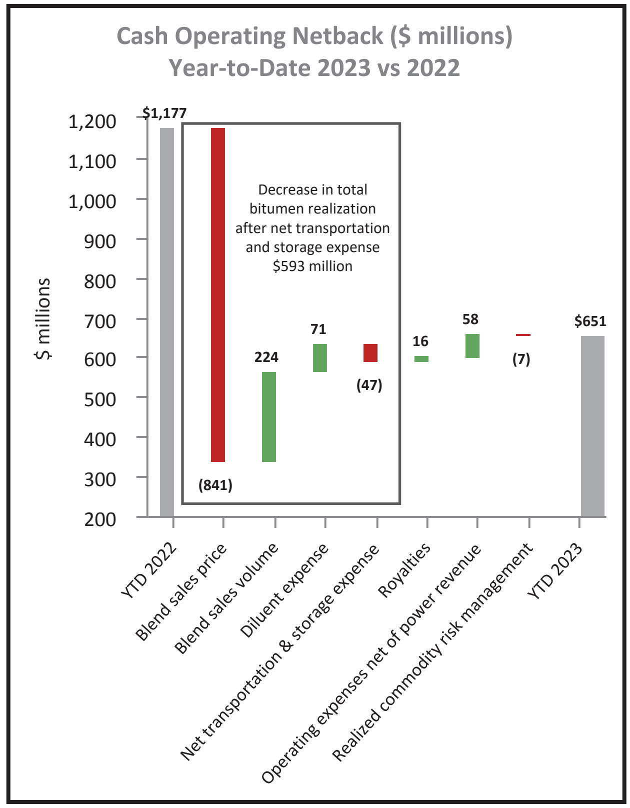
(1) Sales and purchases of oil products mainly related to marketing asset optimization activities.

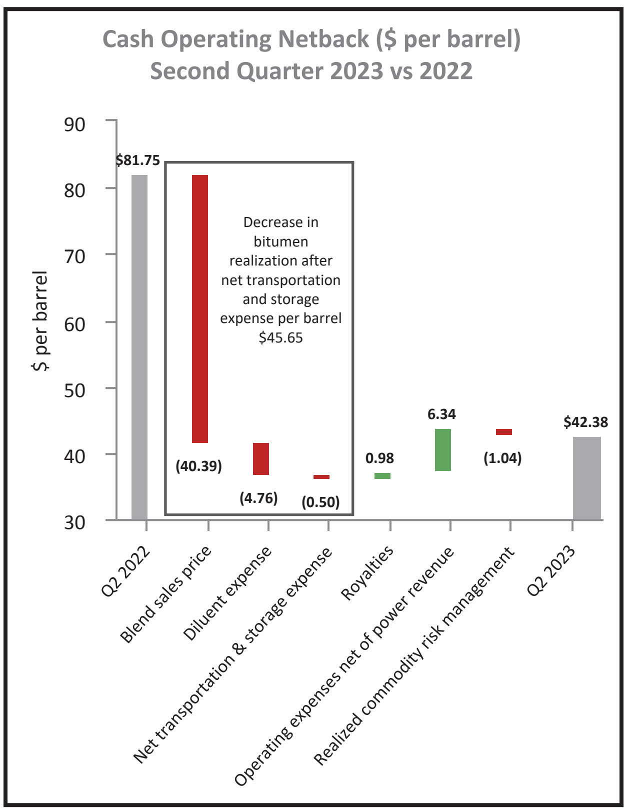
(2) Blend sales per barrel are based on blend sales volumes.

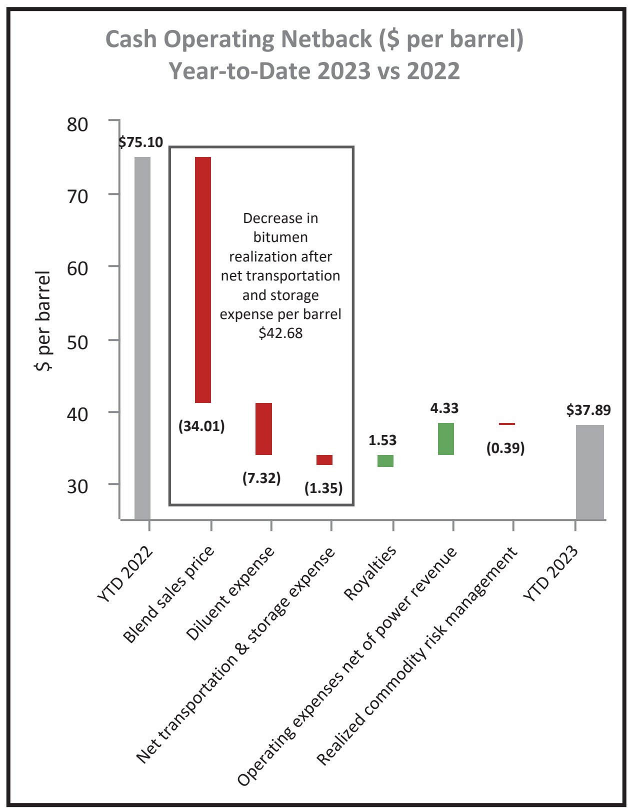
(3) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

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









During the three and six months ended June 30, 2023, cash operating netback decreased over 40% compared to the same periods of 2022. These decreases mainly reflect a lower bitumen realization after net transportation and storage expense partially offset by lower royalties and lower operating expenses net of power revenue.

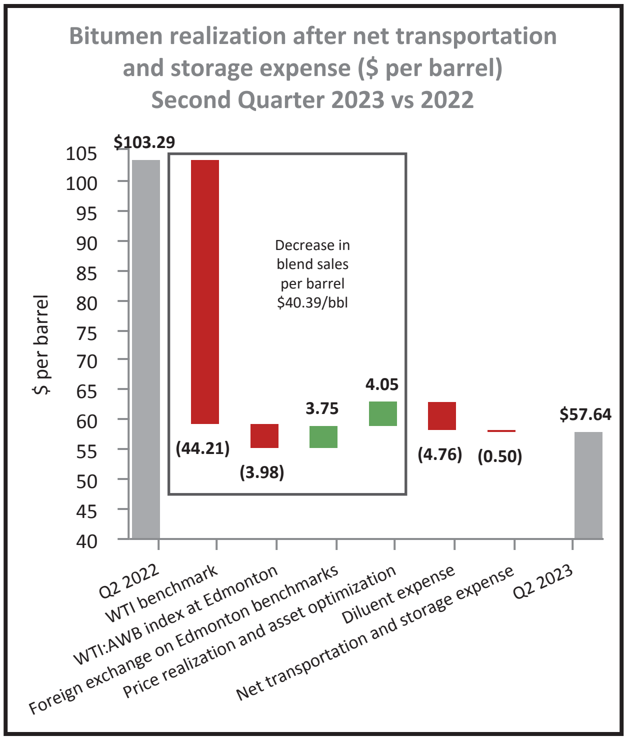
Bitumen Realization after Net Transportation and Storage Expense

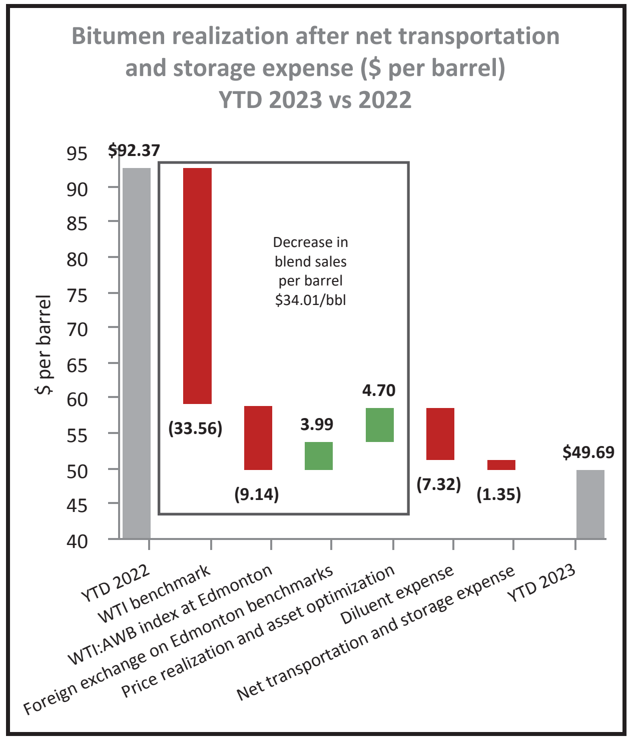
Bitumen realization after net transportation and storage expense represents bitumen sales at Christina Lake and is calculated as blend sales less diluent expense and net transportation and storage expense. Blend sales represents the Corporation's revenue from its oil blend known as AWB, which is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. Diluent expense is impacted by Canadian and U.S. benchmark pricing, the amount of diluent required, which is impacted by pipeline specification seasonality, 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. Diluent volumes are typically held in inventory for 30 to 60 days and approximately 20,000 bbls/d of diluent is sourced from Mont Belvieu, Texas and the remainder from Edmonton. The cost of diluent purchased is partially offset by the sales of such diluent in blend volumes.

The Corporation's marketing strategy focuses on maximizing bitumen realization after net transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access. Bitumen realization after net transportation and storage expense per barrel fluctuates primarily based on average benchmark prices and light:heavy oil differentials.

	Three months ended June 30				Six months ended June 30			
	2023		2022		2023		2022	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Sales from production	$ 942		$ 1,224		$ 1,985		$ 2,617	
Sales from purchased product[1]	383		383		810		544	
Petroleum revenue	$ 1,325		$ 1,607		$ 2,795		$ 3,161	
Purchased product[1]	(373)		(376)		(787)		(536)	
Blend sales[2][3]	$ 952	$ 87.81	$ 1,231	$128.20	$ 2,008	$ 81.22	$ 2,625	$115.23
Diluent expense	(363)	(10.27)	(415)	(5.51)	(861)	(14.48)	(932)	(7.16)
Bitumen realization[3]	$ 589	$ 77.54	$ 816	$122.69	$ 1,147	$ 66.74	$ 1,693	$108.07
Net transportation and storage expense[3]	(151)	(19.90)	(129)	(19.40)	(293)	(17.05)	(246)	(15.70)
Bitumen realization after net transportation and storage expense[3]	$ 438	$ 57.64	$ 687	$103.29	$ 854	$ 49.69	$ 1,447	$ 92.37
Bitumen sales volumes - bbls/d		83,531		73,091		94,942		86,564

(1) *Sales and purchases of oil products mainly 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 14 "Non-GAAP and Other Financial Measures" of this MD&A.*





During the three and six months ended June 30, 2023, bitumen realization after net transportation and storage expense per barrel decreased 44% and 46%, compared to the same periods of 2022, to $57.64 and $49.69, respectively, driven by a lower blend sales price, higher diluent expense and increased net transportation and storage expense.

During the three and six months ended June 30, 2023 the blend sales price per barrel decreased to $87.81 and $81.22, respectively, from $128.20 and $115.23 in the same periods of 2022. The decreases reflect a lower WTI benchmark price and wider WTI:AWB differentials, at both Edmonton and the USGC, partially offset by the realized price improvement from diverse market access and marketing optimization activities as well as a weaker Canadian dollar relative to the U.S. dollar.

The Corporation sold 82% and 68% of its blend sales volumes in the USGC market during the three and six months ended June 30, 2023, respectively, compared to 79% and 67% during the same periods of 2022. Average heavy oil apportionment on the Enbridge mainline system was 1% and 6%, respectively, during the three and six months ended June 30, 2023 and 0% and 5% during the comparable 2022 periods.

Diluent expense per barrel in the three and six months ended June 30, 2023 increased to $10.27 and $14.48, respectively, from $5.51 and $7.16 in the same periods of 2022. The increases mainly reflect a lower recovery of diluent costs through blend sales. Due to wider WTI:AWB differentials, the Corporation recovered 79% and 71% of the cost of diluent through blend sales during the three and six months ended June 30, 2023, respectively, compared to 91% and 88% in the same periods of 2022.

Total diluent expense decreased to $363 million and $861 million in the three and six months ended June 30, 2023, respectively, from $415 million and $932 million in the same periods of 2022, reflecting a lower average cost of diluent, partially offset by higher diluent volumes. The cost per barrel of diluent in the three and six months ended June 30, 2023 was $111.85 and $114.22, respectively, relative to $140.61 and $131.03, in the comparable 2022 periods.

	Three months ended June 30				Six months ended June 30			
	2023		2022		2023		2022	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Transportation and storage expense	**$ (152)**	**$(20.01)**	$ (130)	$(19.57)	**$ (295)**	**$(17.15)**	$ (248)	$(15.86)
Transportation revenue	**1**	**0.11**	1	0.17	**2**	**0.10**	2	0.16
Net transportation and storage expense	**$ (151)**	**$(19.90)**	$ (129)	$(19.40)	**$ (293)**	**$(17.05)**	$ (246)	$(15.70)
Bitumen sales volumes - bbls/d		**83,531**		73,091		**94,942**		86,564

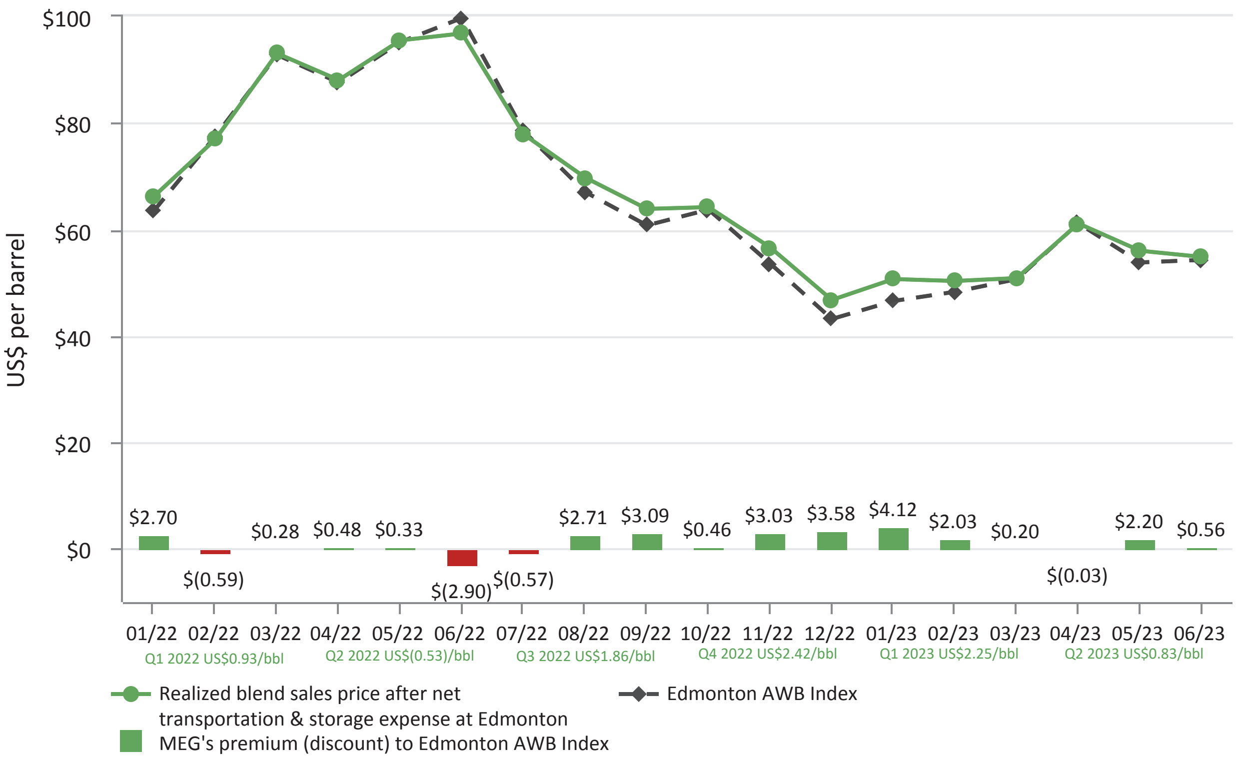
Net transportation and storage expense in the three and six months ended June 30, 2023, on a total and a per barrel basis, rose relative to the same periods of 2022 mainly reflecting higher volumes transported on Flanagan South and Seaway pipeline systems ("FSP"), higher base tolls on FSP and a weaker Canadian dollar relative to the U.S. dollar.

When expressed on a US$ per barrel of blend sales basis, net transportation and storage expense was US$10.39 and US$8.79, respectively, during the three and six months ended June 30, 2023 compared to US$10.53 and US$8.49 during the same periods of 2022, respectively.

The Corporation partially mitigated the cost of transportation and storage assets through the purchase and sale of non-proprietary product. These asset optimization activities increased to $10 million, or $0.90 per barrel, and $23 million, or $0.92 per barrel of blend sales in the three and six months ended June 30, 2023, respectively, from $7 million, or $0.80 per barrel, and $8 million, or $0.36 per barrel of blend sales, in the comparable periods of 2022.

Marketing transportation and storage assets are strategically utilized to access diverse global markets and enhance realized prices. The premium (discount) on the realized blend sales price, net of transportation and storage, at Edmonton relative to the Edmonton AWB index, provides an indication of value derived through transportation and storage commitments.

Premium (discount) on realized blend sales price after net transportation and storage expense, at Edmonton relative to AWB index price at Edmonton



(1) *Quarterly premium (discount) on realized blend sales price after net transportation and storage expense, at Edmonton relative to AWB index price at Edmonton is calculated on volume-weighted average basis.*

In the three and six months ended June 30, 2023, the Corporation's ability to access the USGC increased the realized blend sales price compared to the Edmonton AWB index by US$0.83 and US$1.64 per barrel, respectively.

Royalties

The Oil Sands Royalty Regulation, 2009, establishes royalty rates that are linked to WTI in Canadian dollars. The royalty payable is calculated on bitumen production and applies price-sensitive royalty rates to gross or net revenue depending on whether the project's status is pre or post payout. "Payout" is generally defined as the point in time when a project has generated enough net revenue to recover costs and provide a designated return allowance. When a project reaches payout, its cumulative revenue equals or exceeds cumulative costs.

The pre-payout royalty is based on the project’s gross revenue multiplied by a gross revenue royalty rate. Gross revenues are comprised of bitumen realization after transportation and storage expense attributed to the project. The gross revenue royalty rate starts at 1% and increases every dollar the WTI oil price in Canadian dollars is priced above $55 per barrel, to a maximum of 9% when the Canadian WTI price is $120 per barrel or higher.

The post-payout royalty is the greater of (i) the gross revenue royalty; or (ii) the net revenue royalty. Net revenues are comprised of bitumen realization after transportation and storage expense attributed to the project, and allowed operating and capital costs. The net revenue royalty rate starts at 25% and increases for every dollar the Canadian dollar WTI oil price is above $55 per barrel to a maximum of 40% when the Canadian WTI price is $120 per barrel or higher.

The Corporation’s Christina Lake operation reached payout in the second quarter of 2023.

	Three months ended June 30		Six months ended June 30	
($millions)	2023	2022	2023	2022
Bitumen realization	$ 589	$ 816	$ 1,147	$ 1,693
Transportation and storage expense	(152)	(130)	(295)	(248)
Transportation revenue	1	1	2	2
Bitumen realization after net transportation and storage expense	$ 438	$ 687	$ 854	$ 1,447
Royalties	$ 58	$ 58	$ 89	$ 105
Effective royalty rate(1)(2)	13.2 %	8.5 %	10.4 %	7.3 %

(1) Effective royalty rate is calculated as royalties divided by bitumen realization after net transportation and storage expense.
(2) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

As a result of reaching payout status, the effective royalty rate increased in the three and six months ended June 30, 2023 compared to the same periods of 2022. The royalty impact from lower gross revenue was offset by the higher post-payout royalty rate applicable in the 2023 periods.

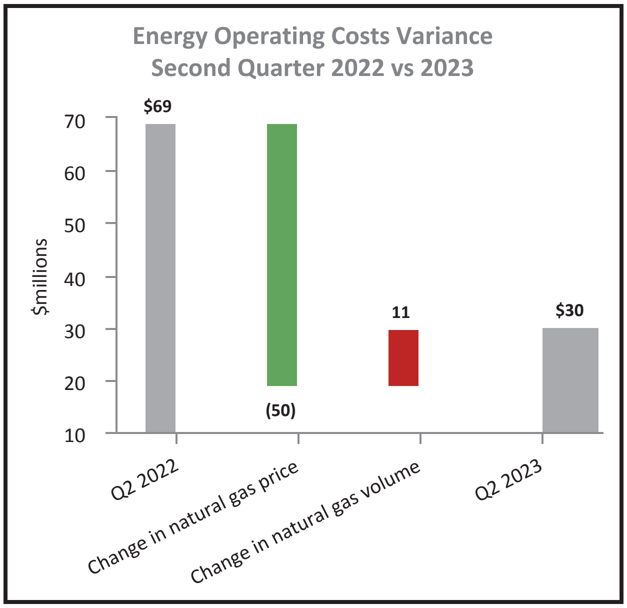
Operating Expenses net of Power Revenue

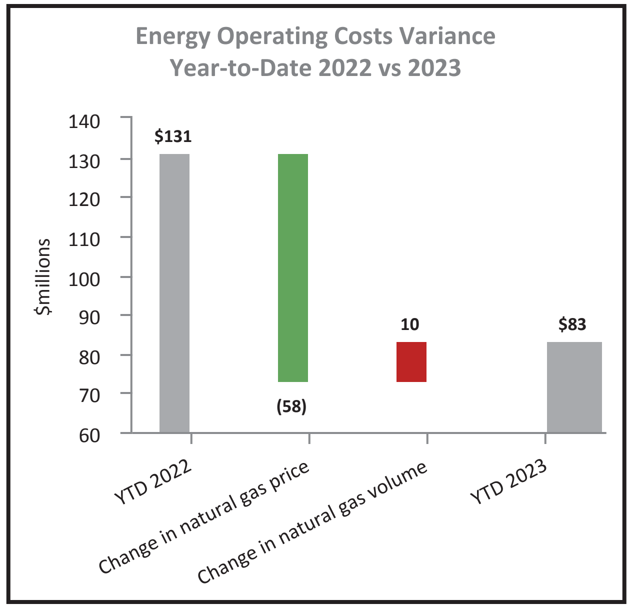
Operating expenses net of power revenue are comprised of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-oriented operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate steam and power. Power revenue is recognized from the sale of surplus power generated by the Christina Lake Project cogeneration facilities. The excess power sold into the Alberta electrical grid displaces other power sources that have a higher carbon intensity, thereby reducing the Corporation's overall carbon footprint.

	Three months ended June 30				Six months ended June 30			
	2023		2022		2023		2022	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Non-energy operating costs(1)	$ (43)	$ (5.66)	$ (38)	$ (5.65)	$ (89)	$ (5.17)	$ (80)	$ (5.13)
Energy operating costs(1)	(30)	(3.92)	(69)	(10.40)	(83)	(4.84)	(131)	(8.33)
Operating expenses	(73)	(9.58)	(107)	(16.05)	(172)	(10.01)	(211)	(13.46)
Power revenue	23	2.95	21	3.08	63	3.66	44	2.78
Operating expenses net of power revenue(2)	$ (50)	$ (6.63)	$ (86)	$(12.97)	$(109)	$ (6.35)	$(167)	$(10.68)
Energy operating costs net of power revenue(2)	$ (7)	$ (0.97)	$ (48)	$ (7.32)	$ (20)	$ (1.18)	$ (87)	$ (5.55)
Average delivered natural gas price (C$/mcf)		$ 3.04		$ 8.17		$ 3.86		$ 6.55
Average realized power sales price (C$/Mwh)		$150.19		$117.94		$158.10		$102.25

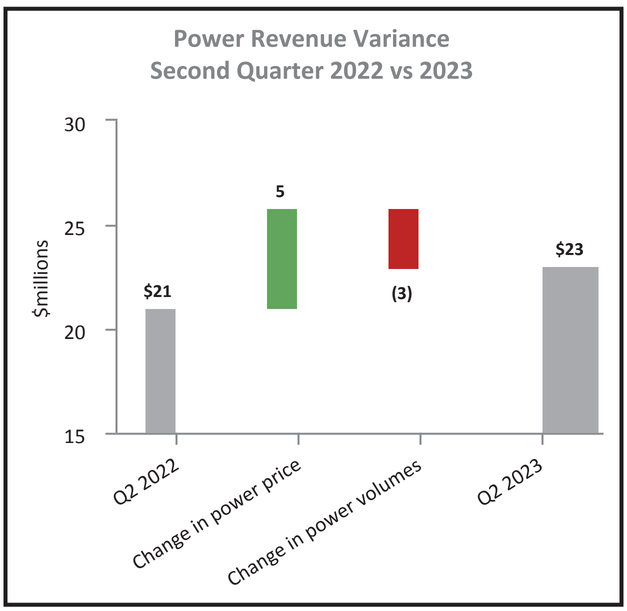
(1) Supplementary financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

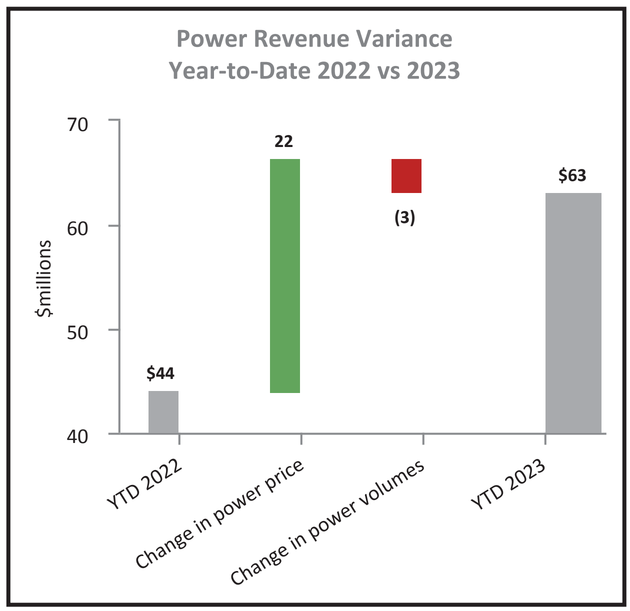
Non-energy operating costs per barrel in the three and six months ended June 30, 2023 were relatively consistent compared to the same periods of 2022. On a total dollar basis, non-energy operating costs increased in the three and six months ended June 30, 2023, compared to the same periods of 2022, primarily reflecting higher production rates and inflationary pressures on cost of services, treating chemicals and staff costs.





Lower energy operating costs in the three and six months ended June 30, 2023, on a total and per barrel basis, reflect a weaker AECO natural gas price partially offset by an increase in purchased natural gas volumes relative to the same periods of 2022.





Power revenue increased during the three and six months ended June 30, 2023, compared to the same periods of 2022, as the realized power price increased by 27% and 55%, respectively. On a total dollar basis, this increase was partially offset by a decrease in power volumes sold in the three and six months ended June 30, 2023.

Energy operating costs net of power revenue per barrel decreased to $0.97 and $1.18 during the three and six months ended June 30, 2023, respectively, from $7.32 and $5.55 during the comparable 2022 periods mainly as a result of a weaker AECO natural gas price.

Realized Gain or Loss on Commodity Risk Management

The Corporation periodically enters financial commodity risk management contracts to manage exposure on blend sales, condensate purchases, natural gas purchases and power sales. Financial commodity risk management contracts are also used to eliminate price risk on marketing asset optimization activities pursuant to Board approved policies.

Refer to the commodity risk management discussion within the "OTHER OPERATING RESULTS" section of this MD&A for further details.

	Three months ended June 30				Six months ended June 30			
	2023		2022		2023		2022	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Realized gain (loss) on commodity risk management	**$ (7)**	**$ (0.94)**	$ 1	$ 0.10	**$ (5)**	**$ (0.28)**	$ 2	$ 0.11

Capital Expenditures

	Three months ended June 30		Six months ended June 30	
($millions)	2023	2022	2023	2022
Sustaining and maintenance	**$ 81**	$ 57	**$ 192**	$ 137
Turnaround	**66**	46	**66**	46
Field infrastructure, corporate and other	**2**	1	**4**	9
	$ 149	$ 104	**$ 262**	$ 192

Increased capital expenditures during the three and six months ended June 30, 2023, compared to the same periods of 2022, were primarily driven by increased sustaining and maintenance costs resulting from increased scope and timing of field development and maintenance activities. Turnarounds at the Christina Lake facility, which occurred in the second quarters of both 2023 and 2022, were successfully completed on time. However, costs in the second quarter of 2023 reflect a larger planned turnaround scope, found work, inflationary pressures on labour costs and ongoing supply chain challenges.

7. OUTLOOK

Bitumen production in the second half of the year is forecast at approximately 105,000 bbls/d moving annual bitumen production towards the low end of the guidance range and non-energy operating costs and G&A expense towards the high end of their respective ranges. The 2023 guidance remains unchanged.

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 FSP capacity. In addition, 20,000 bbls/d of capacity is contracted on the TMX pipeline system to Canada's West Coast. TMX is scheduled to come into service in early 2024, which will further broaden MEG's market access.

Summary of 2023 Guidance	
Capital expenditures	$450 million
Bitumen production - annual average[(1)]	100,000 - 105,000 bbls/d
Non-energy operating costs	$4.75 - $5.05 per bbl
G&A expense	$1.70 - $1.90 per bbl

(1) 2023 guidance includes the bitumen production impact of the second quarter turnaround which impacted annual average bitumen production by approximately 6,000 barrels per day.

8. 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	Six months ended June 30		2023		2022				2021	
	2023	2022	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Crude oil prices										
Brent (US$/bbl)	**80.11**	104.40	**78.01**	82.21	88.59	97.69	111.57	97.23	79.78	73.15
WTI (US$/bbl)	**74.95**	101.35	**73.78**	76.13	82.65	91.55	108.41	94.29	77.19	70.56
Differential – WTI:WCS – Edmonton (US$/bbl)	**(20.02)**	(13.67)	**(15.16)**	(24.88)	(25.89)	(19.86)	(12.80)	(14.53)	(14.64)	(13.58)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(22.50)**	(15.31)	**(17.37)**	(27.63)	(29.14)	(22.80)	(14.25)	(16.35)	(16.40)	(15.13)
AWB – Edmonton (US$/bbl)	**52.45**	86.04	**56.41**	48.50	53.51	68.75	94.16	77.94	60.79	55.43
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(11.25)**	(6.00)	**(7.62)**	(14.87)	(16.35)	(10.15)	(6.15)	(5.85)	(6.40)	(5.57)
AWB – U.S. Gulf Coast (US$/bbl)	**63.70**	95.35	**66.16**	61.26	66.30	81.40	102.26	88.44	70.79	64.99
Enbridge Mainline heavy crude apportionment %	**6**	5	**1**	12	5	3	0	10	21	53
Condensate prices										
Condensate at Edmonton (C$/bbl)	**102.55**	130.06	**97.19**	107.91	113.17	113.97	138.39	121.74	99.70	87.30
Condensate at Edmonton as % of WTI	**101.5**	100.9	**98.1**	104.8	100.9	95.3	100.0	102.0	102.5	98.2
Condensate at Mont Belvieu, Texas (US$/bbl)	**64.33**	91.83	**60.54**	68.13	64.57	72.25	90.98	92.68	76.62	68.19
Condensate at Mont Belvieu, Texas as a % of WTI	**85.8**	90.6	**82.1**	89.5	78.1	78.9	83.9	98.3	99.3	96.6
Natural gas prices										
AECO (C$/mcf)	**3.09**	6.53	**2.67**	3.51	5.57	4.54	7.89	5.16	5.07	3.92
Electric power prices										
Alberta power pool (C$/MWh)	**150.75**	106.48	**159.87**	141.63	213.66	221.90	122.49	90.47	107.25	100.27
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.3475**	1.2714	**1.3430**	1.3520	1.3577	1.3059	1.2766	1.2661	1.2600	1.2602
C$ equivalent of 1 US$ – period end	**1.3238**	1.2872	**1.3238**	1.3528	1.3534	1.3700	1.2872	1.2484	1.2656	1.2750

Crude Oil Prices

Brent is the primary world price benchmark for global light sweet crude oil. 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 production.

Relative to the second quarter of 2022, crude oil prices weakened in the second quarter of 2023 as a result of increased supply certainty and the potential for reduced global demand. During the first half of 2022, global crude pricing strengthened as the Russian invasion of Ukraine and subsequent sanctions against Russia created concern for significant oil supply disruption. The relatively muted impact of sanctions on Russian production and the price cap on Russian crude oil and products combined to ease supply uncertainty and exert downward pressure on crude pricing in the latter half of 2022. Pricing weakened further in the first half of 2023 due to growing global recessionary concerns and the perceived negative impact on oil 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 and can be impacted by apportionment levels on pipelines leaving the Edmonton market. The WCS benchmark at Edmonton reflects heavy oil prices at Hardisty, Alberta.

The Corporation sells AWB, which is similar to WCS but generally prices at a discount reflecting quality differences and heavy sour oil supply/demand fundamentals. AWB is also delivered to the USGC where it is typically sold at a discount to WTI reflecting supply/demand fundamentals for heavy sour oil in that region.

WTI:AWB differentials at both Edmonton and the USGC narrowed in the second quarter of 2023 after widening through late 2022 and early 2023. The narrowing during the second quarter of 2023 reflects seasonal reduction in Canadian heavy oil production due to planned maintenance activity, lower diluent blending requirements and increased heavy crude processing capacity in the U.S. and Asia.

Enbridge Mainline Heavy Crude Apportionment

Enbridge Mainline heavy crude apportionment was 1% and 6% during the three and six months ended June 30, 2023, respectively, compared to 0% and 5% during the same periods of 2022, respectively. The low apportionment levels reflect the Enbridge Line 3 Replacement project which restored 370,000 barrels per day of Western Canadian crude egress. Reduced apportionment allows the Corporation to utilize its committed FSP capacity enabling a higher percentage of sales in the USGC market.

Condensate Prices

In order to facilitate pipeline transportation, the Corporation uses condensate as diluent for blending with the Corporation's bitumen. The price of condensate generally correlates with the price of WTI and is sourced from both the Edmonton area and the USGC, where pricing is generally lower. The Corporation has committed diluent purchases of 20,000 barrels per day from the USGC at Mont Belvieu, Texas benchmark pricing. Condensate pricing at Edmonton, as a percentage of WTI, weakened 2% during the three months ended June 30, 2023 and tightened 1% during the six months ended June 30, 2023, compared to the same periods of 2022, as condensate supply remained tight. Condensate pricing during the three and six months ended June 30, 2023 at Mont Belvieu, Texas weakened 2% and 5% compared to the same periods of 2022 due to a reduction in international demand.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation and is used as fuel to generate steam for the thermal production process and to create steam and electricity from cogeneration facilities. The Corporation purchases natural gas in Alberta based on the AECO natural gas index price. AECO natural gas prices decreased 66% and 53% in the three and six months ended June 30, 2023, respectively, relative to the same periods of 2022 primarily due to an unseasonably mild winter dampening demand, record natural gas production in North America and significantly reduced export pricing for natural gas.

Electric Power Prices

Electric power prices impact the revenue that the Corporation receives on the sale of surplus power from the Christina Lake Project cogeneration facilities. The Alberta power pool price strengthened by 31% and 42% in the three and six months ended June 30, 2023 compared to the same periods of 2022. These increases reflect the pass through of facility operating cost escalation including higher carbon tax costs, increased offer pricing for marginal power generation in Alberta, and elevated export market pricing.

8. OTHER OPERATING RESULTS

General and Administrative

	Three months ended June 30		Six months ended June 30	
($millions, except as indicated)	**2023**	**2022**	**2023**	**2022**
General and administrative expense	**$ 15**	$ 15	**$ 33**	$ 29
General and administrative expense per barrel of production	**$ 1.85**	$ 2.37	**$ 1.90**	$ 1.92
Bitumen production – bbls/d	**85,974**	67,256	**96,349**	84,099

General and administrative ("G&A") expense during the six months ended June 30, 2023 increased compared to the same period of 2022 primarily due to higher staff costs.

Depletion and Depreciation

	Three months ended June 30		Six months ended June 30	
($millions, except as indicated)	**2023**	**2022**	**2023**	**2022**
Depletion and depreciation expense	**$ 117**	$ 87	**$ 260**	$ 211
Depletion and depreciation expense per barrel of production	**$ 14.88**	$ 14.35	**$ 14.87**	$ 13.89
Bitumen production – bbls/d	**85,974**	67,256	**96,349**	84,099

Depletion and depreciation expense rose during the three and six months ended June 30, 2023, compared to the same periods of 2022, primarily due to increased production and an increase in the per barrel depletion and depreciation rate from higher estimated future development costs.

Commodity Risk Management Gain (Loss)

The Corporation periodically enters financial commodity risk management contracts to protect and increase the predictability of cash flow, manage commodity input costs and to support marketing asset optimization activities. 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 settlements during the period. Unrealized gains or losses on financial commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.

	Three months ended June 30		Six months ended June 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Realized:				
Condensate contracts[1]	**$ (2)**	$ —	**$ 2**	$ —
Natural gas contracts[2]	**(5)**	2	**(8)**	3
Marketing asset optimization contracts[3]	**—**	(1)	**1**	(1)
Realized commodity risk management gain (loss)	**$ (7)**	$ 1	**$ (5)**	$ 2
Unrealized:				
Condensate contracts[1]	**$ (10)**	$ 6	**$ 2**	$ 5
Natural gas contracts[2]	**(1)**	(2)	**(13)**	3
Marketing asset optimization contracts[3]	**—**	4	**—**	4
Unrealized commodity risk management gain (loss)	**$ (11)**	$ 8	**$ (11)**	$ 12
Commodity risk management gain (loss)	**$ (18)**	$ 9	**$ (16)**	$ 14

(1) *Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas relative to WTI.*
(2) *Relates to contracts which fix the AECO price on natural gas purchases.*
(3) *The Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months to support marketing asset optimization activities.*

Natural gas prices weakened during the six months ended June 30, 2023 while condensate prices weakened during the second quarter of 2023, resulting in commodity risk management losses. The prices of these commodities generally strengthened during the comparative 2022 periods, resulting in commodity risk management gains.

Stock-based Compensation

	Three months ended June 30		Six months ended June 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Cash-settled expense (recovery)	**$ (1)**	$ 10	**$ 17**	$ 55
Equity-settled expense	**6**	7	**14**	10
Equity price risk management (gain) loss[1]	**—**	(3)	**(9)**	(45)
Stock-based compensation expense	**$ 5**	$ 14	**$ 22**	$ 20

(1) *Relates to financial equity price risk management contracts entered 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 were unrealized until vesting of the related units occurred. All financial equity price risk management contracts were fully realized as at March 31, 2023. See section 11 "Risk Management" of this MD&A for further details.*

The cash-settled expense during the three and six months ended June 30, 2023 was lower than the same periods of 2022 as the Corporation's share price increased more significantly in the first half of 2022 compared to the first half of 2023. Also, there were less units outstanding during the first half of 2023 compared to the same period of 2022. All of the Corporation's outstanding cash-settled RSUs and PSUs vested during the first quarter of 2023 and the only cash-settled units remaining outstanding are deferred share units ("DSUs").

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. The $9 million and $45 million equity price risk management gains in the first half of 2023 and 2022, respectively, reflect the increased share price in each of those periods. As at March 31, 2023, all outstanding cash-settled RSUs and PSUs were fully vested and all financial equity price risk management contracts were fully realized.

Foreign Exchange Gain (Loss), Net

	Three months ended June 30		Six months ended June 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ 31**	$ (73)	**$ 31**	$ (42)
US$ denominated cash and cash equivalents	**(2)**	14	**(3)**	5
Foreign currency risk management contracts	**—**	—	**—**	7
Unrealized net gain (loss) on foreign exchange	**29**	(59)	**28**	(30)
Realized gain (loss) on foreign exchange	**1**	(1)	**1**	(2)
Foreign exchange gain (loss), net	**$ 30**	$ (60)	**$ 29**	$ (32)

C$ equivalent of 1 US$				
Beginning of period	**1.3528**	1.2508	**1.3534**	1.2656
End of period	**1.3238**	1.2872	**1.3238**	1.2872

The Corporation's foreign exchange gain (loss) is driven by fluctuations in the U.S. dollar to Canadian dollar exchange rate. While the primary driver of the foreign exchange gain (loss) is U.S. dollar denominated long-term debt, the magnitude of gains and losses continues to decline as the Corporation repays debt.

During the three and six months ended June 30, 2023, the Canadian dollar strengthened relative to the U.S. dollar by 2% in both periods resulting in unrealized foreign exchange gains of $29 million and $28 million, respectively.

During the three and six months ended June 30, 2022, the Canadian dollar weakened relative to the U.S. dollar by 3% and 2%, respectively, resulting in unrealized foreign exchange losses of $59 million and $30 million, respectively.

Net Finance Expense

	Three months ended June 30		Six months ended June 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Interest expense on long-term debt	**$ 28**	$ 43	**$ 57**	$ 90
Interest expense on lease liabilities	**6**	6	**12**	12
Interest income	**(2)**	(1)	**(4)**	(1)
Net interest expense	**32**	48	**65**	101
Debt extinguishment expense	**2**	12	**6**	12
Accretion on provisions	**3**	2	**6**	4
Net finance expense	**$ 37**	$ 62	**$ 77**	$ 117

Average effective interest rate	**6.4%**	6.7%	**6.4%**	6.7%

Interest expense on long-term debt decreased during the three and six months ended June 30, 2023, compared to the same periods of 2022, primarily reflecting the US$917 million (approximately $1.2 billion) in debt reduction since April 1, 2022.

Debt extinguishment expense decreased during the three and six months ended June 30, 2023, compared to the same periods of 2022, reflecting lower debt repurchases in 2023. Refer to Note 14 of the interim consolidated financial statements for further details.

Income Tax

	Three months ended June 30		Six months ended June 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Earnings (loss) before income taxes	**$ 168**	$ 317	**$ 278**	$ 783
Effective tax rate	**19 %**	29 %	**22 %**	25 %
Income tax expense (recovery)	**$ 32**	$ 92	**$ 61**	$ 196

As at June 30, 2023, the Corporation had approximately $5.4 billion of available Canadian tax pools, including $3.8 billion of non-capital losses and $0.4 billion of capital losses, and recognized a deferred income tax liability of $84 million.

The effective tax rate for the three and six months ended June 30, 2023 differed from the Canadian statutory rate of 23% primarily due to the tax effect of foreign exchange gains and losses on the Corporation's U.S. dollar denominated long-term debt.

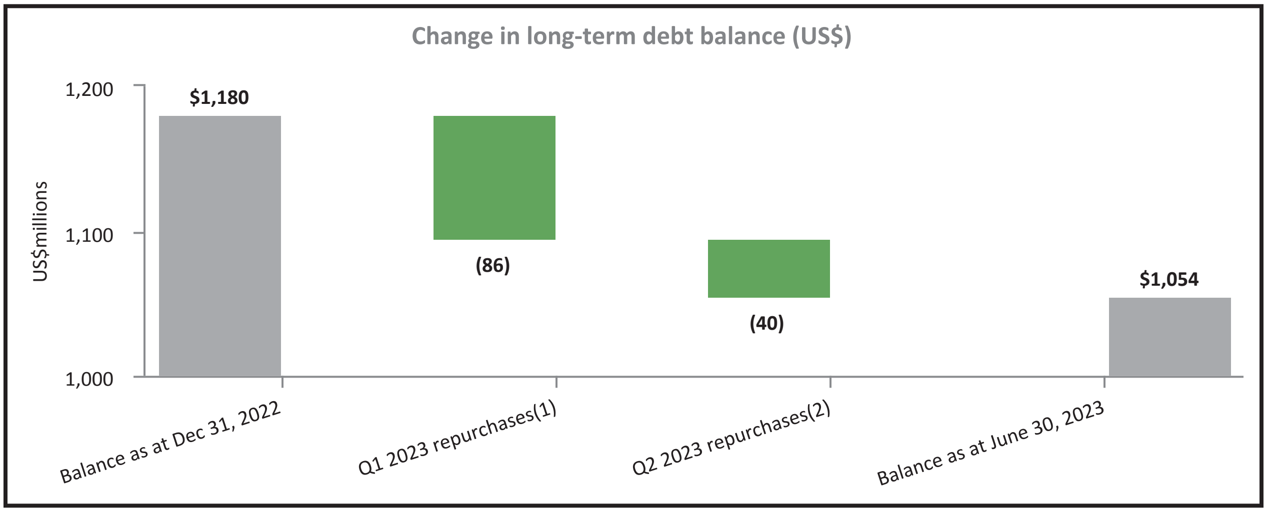
10. LIQUIDITY AND CAPITAL RESOURCES

($millions)	**June 30, 2023**	**December 31, 2022**
Unsecured:		
7.125% senior unsecured notes (June 30, 2023 - US$453.6 million; due 2027; December 31, 2022 - US$579.9 million)	**$ 601**	$ 785
5.875% senior unsecured notes (June 30, 2023 - US$600 million; due 2029; December 31, 2022 - US$600 million)	**794**	812
Unamortized deferred debt discount and debt issue costs	**(13)**	(16)
Current and long-term debt	**1,382**	1,581
Cash and cash equivalents	**(66)**	(192)
Net debt - C$[(1)(2)]	**$ 1,316**	$ 1,389
Net debt - US$[(1)(2)]	**$ 994**	$ 1,026

(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 18 of the interim consolidated financial statements.

(2) On April 14, 2023, S&P Global Ratings raised the Corporation’s long-term issuer credit rating to BB- with a stable outlook from B+ and affirmed the issue-level rating on the Corporation’s senior unsecured notes at BB-. On May 24, 2023 Moody's Investors Service raised the Corporation's long-term issuer rating to Ba3 with a stable outlook from B1 and raised the issue-level rating on the Corporation's senior unsecured notes to B1 from B2.

The Corporation repurchased and extinguished its long-term debt as noted below:



(1) *Weighted average repurchase price of 102.2% plus accrued and unpaid interest on US$86 million of the Corporation's 7.125% senior unsecured notes due 2027.*

(2) *Weighted average repurchase price of 102.3% plus accrued and unpaid interest on US$40 million of the Corporation's 7.125% senior unsecured notes due 2027.*

The Corporation's cash and cash equivalents decreased to $66 million at June 30, 2023 from $192 million at December 31, 2022. Refer to the "Cash Flow Summary" section for further details.

The Corporation's net debt was US$994 million at June 30, 2023 compared to US$1,026 million at December 31, 2022.

At the beginning of 2022, the Corporation started allocating all free cash flow to debt reduction. During the second quarter of 2022, upon reaching net debt of US$1.7 billion, the Corporation initiated the allocation of approximately 25% of free cash flow to share buybacks with the remainder applied to debt reduction. At the end of the third quarter of 2022, net debt declined to US$1.2 billion and free cash flow allocated to share buybacks was raised to approximately 50% with the remainder applied to debt reduction. The current free cash flow allocation strategy will remain in place until net debt reaches US$600 million, which is expected to occur in 2024 at current oil prices.

The Corporation has $1.2 billion of available credit, comprised of $600 million under a revolving credit facility and $600 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 maturity dates of October 31, 2026 and are secured by substantially all the assets of the Corporation.

Commodity market volatility is managed through the Corporation's various financial frameworks. Credit exposure is reduced by targeting sales to primarily investment grade customers. The US$453.6 million of 7.125% senior unsecured notes due February 2027 represents the earliest long-term debt maturity. Additionally, the modified covenant-lite $600 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $300 million or 50%. If drawn in excess of $300 million, or 50%, 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 revolving credit facility plus other debt that is secured on a *pari passu* basis with the revolving credit facility, less cash-on-hand. None of the outstanding long-term debt contains financial maintenance covenants or is secured on a *pari passu* basis with the revolving credit facility.

At June 30, 2023, the Corporation had $600 million of unutilized capacity under the revolving credit facility and $167 million of unutilized capacity remained under the $600 million EDC Facility. Letters of credit issued under the revolving credit facility or EDC Facility are not included in first lien net debt for purposes of calculating the first lien net leverage ratio.

Management believes current capital resources and the ability to manage cash flow and working capital levels allows the Corporation to meet current and future obligations, make scheduled principal and interest payments, and fund 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 project development are dependent on factors discussed in the "RISK FACTORS" section of this MD&A.

Cash Flow Summary

	Three months ended June 30		Six months ended June 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Net cash provided by (used in):				
Operating activities	**$ 244**	$ 611	**$ 481**	$ 928
Investing activities	**(137)**	(92)	**(248)**	(180)
Financing activities	**(123)**	(578)	**(355)**	(869)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(3)**	13	**(4)**	4
Change in cash and cash equivalents	**$ (19)**	$ (46)	**$ (126)**	$ (117)

Cash Flow – Operating Activities

Net cash provided by operating activities during the three and six months ended June 30, 2023 decreased, compared to the same periods of 2022, primarily due to lower realized crude oil prices.

Cash Flow – Investing Activities

Net cash used in investing activities increased $45 million and $68 million during the three and six months ended June 30, 2023, compared to the same periods of 2022, reflecting increased capital spending.

Cash Flow – Financing Activities

Net cash used in financing activities decreased $455 million during the three months ended June 30, 2023, compared to the same period of 2022, primarily due to decreased debt repayment and lower share buybacks under the Corporation's capital allocation strategy.

Net cash used in financing activities decreased $514 million during the six months ended June 30, 2023, compared to the same period of 2022, primarily due to decreased debt repayment partially offset by higher share buybacks under the Corporation's capital allocation strategy.

11. RISK MANAGEMENT

Commodity Price Risk Management

The Corporation periodically enters financial commodity risk management contracts to manage exposure on blend sales, condensate purchases, natural gas purchases and power sales. Financial commodity risk management contracts are also used to eliminate price risk on marketing asset optimization activities pursuant to Board approved policies.

The Corporation periodically enters 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 contracts are recognized in the consolidated statement of earnings (loss) and comprehensive income (loss) and in cash operating netback as the contracts are realized.

The Corporation had the following financial commodity risk management contracts relating to condensate purchases and natural gas purchases outstanding at June 30, 2023:

As at June 30, 2023			
Condensate Purchase Contracts	**Volumes (bbls/d)**	**Term**	**Average Price (US$/bbl)**
WTI:Mont Belvieu Fixed Differential	10,000	Jul 1, 2023 - Oct 31, 2023	$(11.44)
Natural Gas Purchase Contracts	**Volumes (GJ/d)**	**Term**	**Average Price (C$/GJ)**
AECO Fixed Price	35,000	Jul 1, 2023 - Dec 31, 2023	$3.88
AECO Fixed Price	30,000	Jan 1, 2024 - Dec 31, 2024	$4.11

Incremental to these commodity risk management contracts, the Corporation occasionally enters contracts to fix the spread between WTI prices for consecutive months to support marketing asset optimization activities.

The following table summarizes the sensitivity of cash operating netback, adjusted funds flow and earnings (loss) before income tax of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place at June 30, 2023:

Commodity	Sensitivity Range	Increase	Decrease
Condensate purchase price	± 5% in condensate price as a percentage of WTI	**$ 6**	**$ (6)**
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	**$ 9**	**$ (9)**

Equity Price Risk Management

Equity price risk is the risk that changes in the Corporation's own share price impacts earnings and cash flows. Earnings and funds flow from operating activities are impacted when outstanding cash-settled instruments, issued under the stock-based compensation plans, are revalued each period based on the Corporation's share price and recognized in stock-based compensation expense. Net cash provided by (used in) operating activities is impacted when the cash-settled components of these stock-based compensation units are ultimately settled. Equity price risk management (gain) loss is recognized in stock-based compensation expense on the statement of earnings (loss), the unrealized asset (liability) is included in risk management on the balance sheet and any realized asset outstanding at period-end is included in trade receivables and other on the balance sheet. In March 2020, the Corporation entered financial equity price risk management contracts to manage exposure on cash-settled RSUs and PSUs vesting between April 1, 2021 and March 31, 2023.

	Three months ended June 30		Six months ended June 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Unrealized equity price risk management (gain) loss	**$ —**	$ (3)	**$ 78**	$ 1
Realized equity price risk management (gain) loss	**—**	—	**(87)**	(46)
Equity price risk management (gain) loss	**$ —**	$ (3)	**$ (9)**	$ (45)

(1) *As at March 31, 2023, all outstanding cash-settled RSUs and PSUs were fully vested and all financial equity price risk management contracts were fully realized. DSUs are the only cash-settled units remaining outstanding as at June 30, 2023.*

12. SHARES OUTSTANDING

At June 30, 2023, the Corporation had the following share capital instruments outstanding or exercisable:

(thousands)	**Units**
Common shares:	
Outstanding at December 31, 2022	291,081
Issued upon exercise of stock options	126
Issued upon vesting and release of equity-settled RSUs and PSUs	2,377
Repurchased for cancellation	(8,018)
Common shares outstanding at June 30, 2023	**285,566**
Convertible securities:	
Stock options(1)	**168**
Equity-settled RSUs and PSUs	**3,717**

(1) All outstanding stock options were exercisable at June 30, 2023.

In the second quarter of 2023, the Corporation repurchased for cancellation 3.1 million common shares under its NCIB program at a weighted average price of $21.51 for a total cost of $66 million.

At July 27, 2023, the Corporation had 285.4 million common shares outstanding, 0.2 million stock options outstanding and exercisable and 3.7 million equity-settled RSUs and equity-settled PSUs outstanding.

13. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of obligations at June 30, 2023. These estimates may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities and the senior unsecured notes may be retired earlier due to mandatory or discretionary repayments or redemptions.

($millions)	**2023**	**2024**	**2025**	**2026**	**2027**	**Thereafter**	**Total**
Commitments:							
Transportation and storage(1)	$ 219	$ 495	$ 469	$ 448	$ 452	$ 5,514	$ 7,597
Diluent purchases	90	12	—	—	—	—	102
Other operating commitments	9	18	17	17	8	24	93
Variable office lease costs	2	4	4	4	4	17	35
Capital commitments	14	—	—	—	—	—	14
Total Commitments	334	529	490	469	464	5,555	7,841
Other Obligations:							
Lease obligations	19	37	30	29	29	434	578
Current and long-term debt(2)	—	—	—	—	601	794	1,395
Interest on long-term debt(2)	45	89	89	89	52	53	417
Decommissioning obligation(3)	3	4	3	3	3	814	830
Total Commitments and Obligations	**$ 401**	**$ 659**	**$ 612**	**$ 590**	**$ 1,149**	**$ 7,650**	**$ 11,061**

(1) This represents transportation and storage commitments from 2023 to 2048, including the estimated TMX commitment which is not yet in service. The estimated commitment on TMX increased during the second quarter of 2023 to reflect the interim toll. Excludes finance leases recognized on the consolidated balance sheet.

(2) This represents the scheduled principal repayments of the senior unsecured notes and associated interest payments based on interest and foreign exchange rates in effect on June 30, 2023.

(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 and believes that any liabilities that may arise pertaining to such matters would not have a material impact on its financial position.

14. 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 consolidated 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 non-recurring adjustments, 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 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 and return capital to shareholders. Free cash flow is calculated as adjusted funds flow less capital expenditures.

In the second quarter of 2022, an adjustment was made to the presentation of adjusted funds flow and free cash flow. In April 2020, the Corporation issued cash-settled RSUs under its long-term incentive ("LTI") plan when the share price was at a historic low of $1.57 per share. Concurrent with the issuance, the Corporation entered equity price risk management contracts to manage share price volatility in the subsequent three-year period, effectively reducing share price appreciation cash flow risk. The increase in the Corporation's share price from April 2020 to June 30, 2022 resulted in the recognition of a significant cash-settled stock-based compensation expense, which was previously included as a component of adjusted funds flow and free cash flow. The actual cash impact of the 2020 cash-settled RSUs, however, is subject to equity price risk management contracts, so the cash impact over the term of these RSUs has been reduced and the change in value does not provide a valuable indication of operating performance.

Therefore, the financial statement impacts of the April 2020 cash-settled stock-based compensation and the equity price risk management contracts have been excluded from adjusted funds flow and free cash flow. All prior periods presented have been adjusted to reflect this change in presentation.

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

	Three months ended June 30		Six months ended June 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Funds flow from operating activities	**$ 278**	$ 412	**$ 626**	$ 999
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management	**—**	66	**13**	85
Realized equity price risk management gain	**—**	—	**(87)**	(46)
Adjusted funds flow	**278**	478	**552**	1,038
Capital expenditures	**(149)**	(104)	**(262)**	(192)
Free cash flow	**$ 129**	$ 374	**$ 290**	$ 846

Net Debt

Net debt is a capital management measure and is defined in the Corporation's consolidated 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	**June 30, 2023**	**December 31, 2022**
Long-term debt	**$ 1,382**	$ 1,578
Current portion of long-term debt	**—**	3
Cash and cash equivalents	**(66)**	(192)
Net debt - C$	**$ 1,316**	$ 1,389
Net debt - US$	**$ 994**	$ 1,026

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 volumes.

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 revenues to cash operating netback has been provided below:

	Three months ended June 30				Six months ended June 30			
($millions)	**2023**		2022		**2023**		2022	
Revenues	**$**	**1,291**	$	1,571	**$**	**2,771**	$	3,102
Diluent expense		**(363)**		(415)		**(861)**		(932)
Transportation and storage expense		**(152)**		(130)		**(295)**		(248)
Purchased product		**(373)**		(376)		**(787)**		(536)
Operating expenses		**(73)**		(107)		**(172)**		(211)
Realized gain (loss) on commodity risk management		**(7)**		1		**(5)**		2
Cash operating netback	**$**	**323**	$	544	**$**	**651**	$	1,177

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 is based on blend sales volumes and bitumen realization per barrel is based on bitumen sales volumes.

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 blend sales and bitumen realization. A reconciliation from revenues to blend sales and bitumen realization has been provided below:

	Three months ended June 30				Six months ended June 30			
	2023		2022		**2023**		2022	
($millions, except as indicated)		**$/bbl**		$/bbl		**$/bbl**		$/bbl
Revenues	**$ 1,291**		$ 1,571		**$ 2,771**		$ 3,102	
Power and transportation revenue	**(24)**		(22)		**(65)**		(46)	
Royalties	**58**		58		**89**		105	
Petroleum revenue	**1,325**		1,607		**2,795**		3,161	
Purchased product	**(373)**		(376)		**(787)**		(536)	
Blend sales	**952**	**$ 87.81**	1,231	$ 128.20	**2,008**	**$ 81.22**	2,625	$ 115.23
Diluent expense	**(363)**	**(10.27)**	(415)	(5.51)	**(861)**	**(14.48)**	(932)	(7.16)
Bitumen realization	**$ 589**	**$ 77.54**	$ 816	$ 122.69	**$ 1,147**	**$ 66.74**	$ 1,693	$ 108.07

Net Transportation and Storage Expense

Net transportation and storage expense 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.

Transportation and storage expense is an IFRS measure in the Corporation's consolidated statements of earnings (loss) and comprehensive income (loss).

Power and transportation 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 power and transportation revenue to transportation revenue has been provided below.

	Three months ended June 30				Six months ended June 30			
	2023		2022		2023		2022	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Transportation and storage expense	**$ (152)**	**$ (20.01)**	$ (130)	$ (19.57)	**$ (295)**	**$ (17.15)**	$ (248)	$ (15.86)
Power and transportation revenue	**$ 24**		$ 22		**$ 65**		$ 46	
Less power revenue	**(23)**		(21)		**(63)**		(44)	
Transportation revenue	**$ 1**	**$ 0.11**	$ 1	$ 0.17	**$ 2**	**$ 0.10**	$ 2	$ 0.16
Net transportation and storage expense	**$ (151)**	**$ (19.90)**	$ (129)	$ (19.40)	**$ (293)**	**$ (17.05)**	$ (246)	$ (15.70)

Bitumen Realization after Net Transportation and Storage Expense

Bitumen realization after net transportation and storage expense 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 net transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access.

	Three months ended June 30				Six months ended June 30			
	2023		2022		2023		2022	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Bitumen realization[(1)]	**$ 589**	**$ 77.54**	$ 816	$122.69	**$ 1,147**	**$ 66.74**	$ 1,693	$108.07
Net transportation and storage expense[(1)]	**(151)**	**(19.90)**	(129)	(19.40)	**(293)**	**(17.05)**	(246)	(15.70)
Bitumen realization after net transportation and storage expense	**$ 438**	**$ 57.64**	$ 687	$103.29	**$ 854**	**$ 49.69**	$ 1,447	$ 92.37

(1) Non-GAAP financial measure as defined in this section.

Operating Expenses net of Power Revenue and Energy Operating Costs net of Power Revenue

Operating expenses net of power revenue and Energy operating costs net of power revenue are both non-GAAP financial measures, or ratios when expressed on a per barrel basis. 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. Per barrel amounts are based on bitumen sales volumes.

Operating expenses net of power revenue 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.

Energy operating costs net of power revenue is used to measure the performance of the Corporation's cogeneration facilities to offset energy operating costs.

Non-energy operating costs and energy operating costs are supplementary financial measures as they represent portions of operating expenses. Non-energy operating costs comprise 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). Power and transportation 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 power and transportation revenue to power revenue has been provided below.

	Three months ended June 30				Six months ended June 30			
	2023		2022		**2023**		2022	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Non-energy operating costs	**$ (43)**	**$ (5.66)**	$ (38)	$ (5.65)	**$ (89)**	**$ (5.17)**	$ (80)	$ (5.13)
Energy operating costs	**(30)**	**(3.92)**	(69)	(10.40)	**(83)**	**(4.84)**	(131)	(8.33)
Operating expenses	**$ (73)**	**$ (9.58)**	$ (107)	$ (16.05)	**$ (172)**	**$ (10.01)**	$ (211)	$ (13.46)
Power and transportation revenue	**$ 24**		$ 22		**$ 65**		$ 46	
Less transportation revenue	**(1)**		(1)		**(2)**		(2)	
Power revenue	**$ 23**	**$ 2.95**	$ 21	$ 3.08	**$ 63**	**$ 3.66**	$ 44	$ 2.78
Operating expenses net of power revenue	**$ (50)**	**$ (6.63)**	$ (86)	$ (12.97)	**$ (109)**	**$ (6.35)**	$ (167)	$ (10.68)
Energy operating costs net of power revenue	**$ (7)**	**$ (0.97)**	$ (48)	$ (7.32)	**$ (20)**	**$ (1.18)**	$ (87)	$ (5.55)

Effective royalty rate

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

Effective royalty rate enables a comparison between pre- and post-payout Crown royalties by calculating a royalty rate on a consistent basis. The actual royalty rate applied will differ from the effective royalty rate.

The effective royalty rate is calculated as royalty expense divided by bitumen realization after net transportation and storage expense (non-GAAP measure reconciled above).

	Three months ended June 30		Six months ended June 30	
($millions)	**2023**	2022	**2023**	2022
Bitumen realization	**$ 589**	$ 816	**$ 1,147**	$ 1,693
Transportation and storage expense	**(152)**	(130)	**(295)**	(248)
Transportation revenue	**1**	1	**2**	2
Bitumen realization after net transportation and storage expense	**$ 438**	$ 687	**$ 854**	$ 1,447
Royalties	**$ 58**	$ 58	**$ 89**	$ 105
Effective royalty rate	**13.2 %**	8.4 %	**10.4 %**	7.3 %

15. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting policies and estimates are those estimates having a significant impact on the 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 can be found in the Corporation's annual consolidated financial statements for the year ended December 31, 2022.

16. 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.sedarplus.ca.

17. 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.

18. 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, will 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.

19. 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
ERM	Enterprise Risk Management
ESG	Environment, Social and Governance
FSP	Flanagan South and Seaway Pipeline
G&A	General and Administrative
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse Gas
IFRS	International Financial Reporting Standards
LTI	Long-term incentive
NCIB	Normal course issuer bid
MD&A	Management's Discussion and Analysis
OPEC	Organization of Petroleum Exporting Countries
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam-oil ratio
SBC	Stock-based compensation
TMX	Trans Mountain Expansion
U.S.	United States
US$	United States dollars
USGC	United States Gulf Coast
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

20. 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; statements regarding the Corporation’s estimated reserves; the Corporation’s expectation that the Christina Lake Project has an oil processing capacity of approximately 110,000 bbls/d at a current steam oil-oil ratio of 2.2 prior to any impact from scheduled maintenance activity or outages; the Corporation’s statement that the typical average production decline rate at the Christina Lake Project is approximately 10% to 15%; the Corporation’s statement that, at an annual production level of 103,700 bbl/d, MEG has a 2P reserves life index of greater than 50 years; the impact on SOR of the Corporation’s proprietary reservoir technology and enhanced completion designs, optimized inter-well spacing and development and redevelopment program; the Corporation’s marketing strategy and marketing asset optimization strategy; the Corporation’s expectations regarding the Pathways Alliance projects and government support of these projects; the Corporation’s expectation that its marketing transportation and storage assets will enable it to access diverse global markets and enhance realized prices; 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; all statements relating to the Corporation’s annual 2023 guidance, including its full year production, non-energy operating costs, G&A expense, capital expenditures and transportation costs and all statements relating to the Corporation’s effective royalty rate; the Corporation’s expectation that TMX will come into service in early 2024; the Corporation’s expectations regarding global crude oil prices and global crude oil demand and supply balances; the Corporation’s expectation of allocating 50% of free cash flow to share buybacks with the remaining cash flow applied to ongoing debt reduction until it reaches a net debt floor of US$600 million, which is expected to occur in 2024 at current oil prices; the Corporation’s continued focus on debt reduction as a key component of its capital allocation strategy; 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 2023 and 2024 commodity risk management contracts.

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 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 impact of the Russian invasion of Ukraine and associated sanctions on commodity prices; 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.sedarplus.ca.

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.

21. 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.sedarplus.ca.

22. QUARTERLY SUMMARIES

	2023		2022				2021	
Unaudited	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**136**	81	159	156	225	362	177	54
Per share, diluted	**0.47**	0.28	0.53	0.51	0.72	1.15	0.57	0.17
Funds flow from operating activities	**278**	348	383	501	412	587	260	212
Per share, diluted	**0.96**	1.19	1.28	1.63	1.31	1.87	0.83	0.68
Adjusted funds flow(1)	**278**	274	401	496	478	559	274	243
Per share, diluted(1)	**0.96**	0.94	1.34	1.61	1.52	1.78	0.88	0.78
Capital expenditures	**149**	113	106	78	104	88	106	84
Free cash flow(1)	**129**	161	295	418	374	471	168	159
Working capital	**231**	219	289	395	437	465	150	199
Net debt - C$(1)	**1,316**	1,381	1,389	1,634	1,782	2,150	2,401	2,559
Net debt - US$(1)	**994**	1,020	1,026	1,193	1,384	1,722	1,897	2,007
Shareholders' equity	**4,441**	4,370	4,383	4,418	4,339	4,178	3,808	3,628
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**73.78**	76.13	82.65	91.55	108.41	94.29	77.19	70.56
Differential – WTI:WCS – Edmonton (US$/bbl)	**(15.16)**	(24.88)	(25.89)	(19.86)	(12.80)	(14.53)	(14.64)	(13.58)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(17.37)**	(27.63)	(29.14)	(22.80)	(14.25)	(16.35)	(16.40)	(15.13)
AWB – Edmonton (US$/bbl)	**56.41**	48.50	53.51	68.75	94.16	77.94	60.79	55.43
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(7.62)**	(14.87)	(16.35)	(10.15)	(6.15)	(5.85)	(6.40)	(5.57)
AWB – U.S. Gulf Coast (US$/bbl)	**66.16**	61.26	66.30	81.40	102.26	88.44	70.79	64.99
Enbridge Mainline heavy apportionment	**1 %**	12 %	5 %	3 %	0 %	10 %	21 %	53 %
C$ equivalent of 1US$ – average	**1.3430**	1.3520	1.3577	1.3059	1.2766	1.2661	1.2600	1.2602
Natural gas – AECO ($/mcf)	**2.67**	3.51	5.57	4.54	7.89	5.16	5.07	3.92
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**119,187**	154,197	160,163	131,327	105,517	146,382	141,280	127,546
Diluent usage – bbls/d	**(35,656)**	(47,717)	(46,581)	(35,568)	(32,426)	(46,196)	(42,386)	(35,295)
Bitumen sales – bbls/d	**83,531**	106,480	113,582	95,759	73,091	100,186	98,894	92,251
Bitumen production – bbls/d	**85,974**	106,840	110,805	101,983	67,256	101,128	100,698	91,506
Steam-oil ratio (SOR)	**2.25**	2.25	2.22	2.39	2.46	2.43	2.42	2.56
Blend sales(2)	**87.81**	76.07	83.28	99.96	128.20	105.79	82.43	74.54
Diluent expense	**(10.27)**	(17.89)	(14.12)	(9.63)	(5.51)	(8.51)	(11.37)	(9.63)
Net transportation and storage expense(2)	**(19.90)**	(14.78)	(14.41)	(15.58)	(19.40)	(12.97)	(11.39)	(10.03)
Bitumen realization after net transportation and storage expense(2)	**57.64**	43.40	54.75	74.75	103.29	84.31	59.67	54.88
Royalties	**(7.69)**	(3.18)	(5.15)	(7.47)	(8.67)	(5.24)	(3.54)	(2.67)
Non-energy operating costs(3)	**(5.66)**	(4.77)	(4.34)	(4.49)	(5.65)	(4.74)	(4.56)	(4.46)
Energy operating costs(3)	**(3.92)**	(5.57)	(6.71)	(6.12)	(10.40)	(6.80)	(6.22)	(4.77)
Power revenue	**2.95**	4.21	5.22	5.16	3.08	2.56	2.58	2.06
Realized gain (loss) on commodity risk management	**(0.94)**	0.23	0.12	0.80	0.10	0.12	(10.06)	(7.73)
Cash operating netback(2)	**42.38**	34.32	43.89	62.63	81.75	70.21	37.87	37.31
Revenues	**1,291**	1,480	1,445	1,571	1,571	1,531	1,307	1,091
Power sales price (C$/MWh)	**150.19**	162.90	219.81	217.25	117.94	91.50	95.22	82.17
Power sales (MW/h)	**71**	118	116	98	82	121	117	101
Average cost of diluent ($/bbl of diluent)	**111.85**	116.01	117.72	125.91	140.61	124.23	108.96	99.69
Average cost of diluent as a % of WTI	**113 %**	113 %	105 %	105 %	102 %	104 %	112 %	112 %
Depletion and depreciation rate per bbl of production	**14.88**	14.86	15.84	14.30	14.35	13.58	13.63	12.78
General and administrative expense per bbl of production	**1.85**	1.94	1.62	1.72	2.37	1.61	1.58	1.72
COMMON SHARES								
Shares outstanding, end of period (000)	**285,566**	288,614	291,081	301,649	307,271	307,596	306,865	306,773
Common share price ($) - close (end of period)	**21.00**	21.71	18.85	15.46	17.82	17.07	11.70	9.89

(1) *Capital management measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.*
(2) *Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Supplementary financial measure - please refer to section 14 "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:

- significant variability in blend sales pricing primarily due to high volatility in the price of WTI which ranged from a quarterly average of US$70.56/bbl to US$108.41/bbl;
- variability in WTI:AWB differentials;
- 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;
- transition of royalty status for the Christina Lake project from pre-payout to post-payout, which impacts the Crown royalty rate and resulting royalty expense;
- timing of capital projects;
- inflationary pressure;
- pipeline apportionment and the ability to reach USGC markets;
- fluctuations in natural gas and power pricing;
- gains and losses on risk management contracts;
- changes in depletion and depreciation expense as a result of changes in production rates and future development costs;
- changes in the Corporation's share price and the resulting impact on stock-based compensation and financial equity price risk management contracts; and
- planned turnaround, unplanned outages and other maintenance activities affecting production.

23. ANNUAL SUMMARIES

	2022	2021	2020	2019	2018[1]	2017[1]	2016[1]
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	902	283	(357)	(62)	(119)	166	(429)
Per share, diluted	2.92	0.91	(1.18)	(0.21)	(0.40)	0.57	(1.90)
Funds flow from operating activities	1,882	753	239	741	169	343	(69)
Per share, diluted	6.09	2.42	0.78	2.46	0.56	1.18	(0.31)
Adjusted funds flow[2]	1,934	826	281	724	175	371	(63)
Per share, diluted[2]	6.26	2.65	0.92	2.41	0.58	1.28	(0.28)
Capital expenditures	376	331	149	198	622	508	140
Free cash flow[2]	1,558	495	132	526	(447)	(137)	(203)
Working capital	289	150	55	123	290	313	96
Net debt - C$[2]	1,389	2,401	2,798	2,917	3,422	4,205	4,897
Net debt - US$[2]	1,026	1,897	2,194	2,250	2,508	3,359	3,647
Shareholders' equity	4,383	3,808	3,506	3,853	3,886	3,964	3,287
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/bbl)	94.23	67.91	39.40	57.03	64.77	50.95	43.33
Differential – WTI:WCS – Edmonton (US$/bbl)	(18.27)	(13.04)	(12.60)	(12.76)	(26.31)	(11.98)	(13.84)
Differential – WTI:AWB – Edmonton (US$/bbl)	(20.64)	(14.71)	(14.32)	(14.95)	(29.99)	(14.09)	(16.40)
AWB – Edmonton (US$/bbl)	73.59	53.20	25.08	42.08	34.78	36.86	26.93
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	(9.62)	(4.60)	(4.77)	(1.77)	(6.68)	(7.61)	(11.53)
AWB - U.S. Gulf Coast (US$/bbl)	84.61	63.31	34.63	55.26	58.09	43.34	31.80
Enbridge Mainline heavy apportionment	5 %	42 %	24 %	43 %	41 %	20 %	12 %
C$ equivalent of 1US$ – average	1.3016	1.2536	1.3413	1.3269	1.2962	1.2980	1.3256
Natural gas – AECO ($/mcf)	5.79	3.95	2.43	1.92	1.62	2.29	2.25
OPERATIONAL **($/bbl unless specified)**							
Blend sales, net of purchased product – bbls/d	135,873	131,659	118,347	134,223	125,368	115,766	116,586
Diluent usage – bbls/d	(40,182)	(39,521)	(35,626)	(40,637)	(38,317)	(35,766)	(36,159)
Bitumen sales – bbls/d	95,691	92,138	82,721	93,586	87,051	80,000	80,427
Bitumen production – bbls/d	95,338	93,733	82,441	93,082	87,731	80,774	81,245
Steam-oil ratio (SOR)	2.36	2.43	2.32	2.22	2.19	2.31	2.29
Blend sales[3]	102.02	72.20	37.65	61.29	53.47	51.39	38.19
Diluent expense	(10.07)	(9.73)	(10.42)	(8.08)	(16.78)	(9.36)	(10.28)
Net transportation and storage expense[3]	(15.29)	(10.93)	(12.92)	(10.84)	(8.42)	(6.89)	(6.46)
Bitumen realization after net transportation & storage expense[3]	76.66	51.54	14.31	42.37	28.27	35.14	21.45
Curtailment	—	—	0.06	(0.37)	—	—	—
Royalties	(6.43)	(2.25)	(0.31)	(1.30)	(1.20)	(0.77)	(0.29)
Non-energy operating costs[4]	(4.73)	(4.24)	(4.38)	(4.61)	(4.62)	(4.62)	(5.62)
Energy operating costs[4]	(7.29)	(4.94)	(3.29)	(2.38)	(1.98)	(2.98)	(3.01)
Power revenue	4.11	2.58	1.49	1.75	1.51	0.76	0.64
Realized gain (loss) on commodity risk management	0.29	(9.32)	11.34	(3.31)	(4.37)	(0.39)	0.08
Cash operating netback[3]	62.61	33.37	19.22	32.15	17.61	27.14	13.25
Revenues	6,118	4,321	2,292	3,931	2,733	2,474	1,866
Power sales price (C$/MWh)	162.33	90.10	47.81	56.70	47.87	21.49	18.74
Power sales (MW/h)	104	115	108	121	114	118	115
Average cost of diluent ($/bbl of diluent)	126.00	94.88	61.86	79.89	91.60	72.32	61.06
Average cost of diluent as a % of WTI	103 %	111 %	117 %	106 %	109 %	109 %	106 %
Depletion and depreciation rate per bbl of production	14.57	13.15	13.60	20.90	14.12	16.13	16.81
General and administrative expense per bbl of production	1.78	1.65	1.62	1.99	2.58	2.94	3.24
COMMON SHARES							
Shares outstanding, end of period (000)	291,081	306,865	302,681	299,508	296,841	294,104	226,467
Common share price ($) - close (end of period)	18.85	11.70	4.45	7.39	7.71	5.14	9.23

(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 14 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.*
(4) *Supplementary financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.*