Report to Shareholders for the period ended March 31, 2025

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

MEG Energy Corp. reported its first quarter 2025 operational and financial results on May 6, 2025.[1]

“The work we’ve done over the past few years establishes a strong financial foundation and lays the groundwork for the next phase of production growth. MEG is in an enviable position to deliver substantial growth in free cash flow per share even through uncertain commodity price environments,” said Darlene Gates, President and Chief Executive Officer of MEG. “We remain focused on disciplined spending, operational excellence, and delivering value to our shareholders. We’ll continue to navigate market dynamics with agility and prudence, ensuring we’re well-positioned for long-term success.”

Highlights:

- Delivered first quarter production of 103,224 bbls/d at a leading 2.28 steam-oil ratio ("SOR");
- Generated funds from operations ("FFO") of $380 million ($1.47 per share), an increase of 24% from Q1 2024;
- Reported free cash flow ("FCF") of $223 million ($0.86 per share) after funding $157 million of capital expenditures;
- Returned $185 million of capital to shareholders:
    - Repurchased and cancelled 6.7 million shares, or 3% of total shares outstanding at December 31, 2024, for $159 million; and
    - Paid a quarterly cash dividend of $26 million, or $0.10 per share, on January 15, 2025;
- Incurred non-energy operating costs of $5.84 per barrel and energy operating costs net of power revenue of $2.06 per barrel;
- The Corporation’s 2025 operating and capital guidance remains unchanged; and
- On May 6, 2025, the Corporation's Board of Directors declared a quarterly base dividend of $0.10 per share for payment on July 15, 2025, to shareholders of record on June 16, 2025.

Financial Results

FFO in the first quarter of 2025 was $380 million compared to $329 million in the same period of 2024. The 16% increase was mainly driven by a higher cash operating netback and a lower interest expense due to reduced debt levels.

On a diluted per-share basis, FFO increased 24%, to $1.47, in the first quarter of 2025 from $1.19 in the comparative 2024 period reflecting the combined impact of increased FFO and the reduced number of shares outstanding as a result of share repurchases.

[1] All financial figures are expressed in Canadian dollars ($ or C$) and all references to barrels are per barrel of bitumen, unless otherwise noted. The Corporation's Non-GAAP and Other Financial Measures are detailed in the Advisory section of this report to shareholders. They include: cash operating netback, bitumen realization net of transportation and storage expense, operating expenses net of power revenue, energy operating costs net of power revenue, non-energy operating costs, energy operating costs, funds from operations and free cash flow.

Cash operating netback increased to $46.30 per barrel during the first quarter of 2025 from $39.99 per barrel in the same period of 2024, mainly reflecting a higher bitumen realization after net transportation and storage expense and lower royalties partially offset by higher operating expenses net of power revenue.

Bitumen realization after net transportation and storage expense increased 10%, to $65.98 per barrel, in the first quarter of 2025 from $60.10 per barrel in the same period of 2024. The benefits from a US$6.64 per barrel narrower WTI:WCS differential, the positive impact of a weaker Canadian dollar, higher price realization associated with diverse market access and lower diluent expense were partially offset by a lower average WTI price and higher net transportation and storage expense.

After funding capital expenditures of $157 million, MEG generated $223 million of FCF which was used to return $185 million to shareholders. During the first quarter of 2025, the Corporation repurchased and cancelled 3% of total shares outstanding at December 31, 2024, or 6.7 million shares, for $159 million and paid $26 million of dividends.

First quarter net earnings were $211 million in 2025, compared to $98 million in 2024, driven by higher FFO, lower depletion and depreciation expense and a reduced unrealized foreign exchange loss partially offset by higher deferred income tax expense.

Operational Results

Average first quarter 2025 bitumen production was 103,224 barrels per day at 2.28 SOR, compared to 104,088 barrels per day in the same period of 2024 at a 2.37 SOR. The lower SOR reflects improved reservoir quality and optimized design of recent wells.

Per barrel non-energy operating costs were $5.84 in the first quarter of 2025, compared to $5.18 in the same period of 2024, primarily reflecting expected increases in process treating costs and services as a result of new well pads.

Energy operating costs net of power revenue rose to $2.06 per barrel in the first quarter of 2025 from $1.19 per barrel in the comparative 2024 period. The benefit associated with a weaker AECO natural gas price was more than offset by a lower realized power price. Revenue from the sale of excess power generated by the Corporation's cogeneration facilities offset 34% of energy operating costs in the first quarter of 2025 compared to 69% in the comparative 2024 period.

Capital expenditures increased to $157 million in the first quarter of 2025, from $112 million in the same period of 2024, primarily reflecting the planned investment in the Facility Expansion Project and field and facility infrastructure costs.

Capital Allocation Strategy

The Corporation intends to return 100% of free cash flow to shareholders through a combination of share repurchases and payment of a quarterly base dividend while preserving balance sheet quality and managing working capital cash requirements.

On May 6, 2025, the Corporation's Board of Directors declared a quarterly base dividend of $0.10 per share for payment on July 15, 2025, to shareholders of record on June 16, 2025. Declaration of dividends is at the discretion of the Board of Directors. All dividends paid by MEG are designated as eligible dividends for Canadian federal income tax purposes.

On March 6, 2025, the Toronto Stock Exchange approved the renewal of the Corporation's normal course issuer bid ("NCIB"). Pursuant to the NCIB, MEG may, at its discretion, purchase and cancel up to a maximum of 22,535,791 common shares of the Corporation. The NCIB became effective on March 11, 2025, and will terminate on March 10, 2026 or such earlier time as the NCIB is completed or terminated at the option of MEG.

Outlook

The Corporation's 2025 operating and capital guidance released on November 25, 2024 remains unchanged.

Summary of 2025 Guidance	
Capital expenditures	$635 million
Bitumen production - 2025 annual average	95,000 to 105,000 bbls/d
Non-energy operating costs	$5.30 to $5.80 per bbl

Funds from Operations Sensitivity

MEG's production is composed entirely of crude oil, and FFO is highly correlated with crude oil benchmark prices and light-heavy oil differentials. The following table provides an annual sensitivity estimate to the most significant market variables.

Variable	Range	2025 FFO Sensitivity[(1)(2)] - C$
WCS Differential (US$/bbl)	+/- US$1.00/bbl	+/- C$46mm
WTI (US$/bbl)	+/- US$1.00/bbl	+/- C$32mm
Bitumen Production (bbls/d)	+/- 1,000 bbls/d	+/- C$16mm
Condensate (US$/bbl)	+/- US$1.00/bbl	+/- C$14mm
Exchange Rate (C$/US$)	+/- $0.01	+/- C$10mm
Non-Energy Opex (C$/bbl)	+/- C$0.25/bbl	+/- C$6mm
AECO Gas[(3)] (C$/GJ)	+/- C$0.50/GJ	+/- C$5mm

(1) Each sensitivity is independent of changes to other variables.

(2) Assumes mid-point of 2025 production guidance, US$70.00/bbl WTI, ~US$13.00/bbl Edmonton/PADD II WTI:WCS discount, C$1.35/US$ F/X rate, condensate purchased at 100% of WTI, and one bbl of bitumen per 1.42 bbls of blend sales (1.42 blend ratio).

(3) Assumes 1.3 GJ/bbl of bitumen, 64% of 150 MW of power generation sold externally and a 25.0 heat rate (every $0.50/GJ change in AECO natural gas price changes the power price by C$12.50/MWh).

ADVISORY

Forward-Looking Information

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

Non-GAAP and Other Financial Measures

Certain financial measures in this report to shareholders are non-GAAP financial measures or ratios, supplementary financial measures and capital management measures. These measures are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP and other financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Please refer to section 11 "Non-GAAP and Other Financial Measures" of the Corporation's period ended March 31, 2025 Management's Discussion and Analysis for detailed descriptions of these measures.

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three months ended March 31, 2025 was approved by the Corporation's Board of Directors on May 6, 2025. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three months ended March 31, 2025, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2024, the 2024 annual MD&A and the 2024 Annual Information Form ("AIF").

Basis of Presentation

This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards") 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.

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 Accounting Standards 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 Accounting Standards. Please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A for further descriptions of the measures noted below.

Non-GAAP financial measures and ratios include: 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, and per barrel figures associated with non-GAAP financial measures.

Supplementary financial measures and ratios include: non-energy operating costs, energy operating costs, and per barrel figures associated with supplementary financial measures.

Capital management measures include: funds from operations, free cash flow, and net debt.

MD&A - Table of Contents

1. HIGHLIGHTS

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

	2025	2024			
($millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Operational results:					
Bitumen production - bbls/d	**103,224**	100,139	103,298	100,531	104,088
Per share, diluted	**0.04**	0.03	0.04	0.03	0.03
Steam-oil ratio	**2.28**	2.40	2.36	2.44	2.37
Bitumen sales - bbls/d	**102,126**	100,821	105,255	93,140	105,534
Business environment:					
WTI - US$/bbl	**71.42**	70.27	75.09	80.57	76.96
Differential - WTI:WCS - Edmonton - US$/bbl	**(12.67)**	(12.56)	(13.55)	(13.61)	(19.31)
AWB - Edmonton - US$/bbl	**57.77**	56.82	60.62	65.99	55.96
C$ equivalent of 1 US$ – average	**1.4350**	1.3991	1.3636	1.3684	1.3488
Financial results:					
Bitumen realization after net transportation and storage expense(1) - $/bbl	**65.98**	62.62	65.61	73.84	60.10
Non-energy operating costs(2) - $/bbl	**5.84**	5.61	5.18	5.63	5.18
Energy operating costs net of power revenue(1) - $/bbl	**2.06**	0.90	0.64	0.99	1.19
Operating expenses net of power revenue(1) - $/bbl	**7.90**	6.51	5.82	6.62	6.37
Cash operating netback(1) - $/bbl	**46.30**	41.09	41.35	47.14	39.99
Royalties	**108**	132	169	162	128
Funds from operations(3)	**380**	340	362	354	329
Per share, diluted	**1.47**	1.29	1.34	1.30	1.19
Capital expenditures	**157**	172	141	123	112
Free cash flow(3)	**223**	168	221	231	217
Per share, diluted	**0.86**	0.64	0.82	0.85	0.78
Weighted average common shares outstanding - diluted	**258**	263	269	272	276
Debt repayments - US$	**—**	—	100	53	105
Share repurchases - C$	**159**	151	108	68	127
Dividends paid - C$	**26**	27	—	—	—
Revenues	**1,162**	1,147	1,265	1,373	1,364
Net earnings	**211**	106	167	136	98
Per share, diluted	**0.82**	0.40	0.62	0.50	0.36

(1) *Non-GAAP financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.*
(2) *Supplementary financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Capital management measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.*

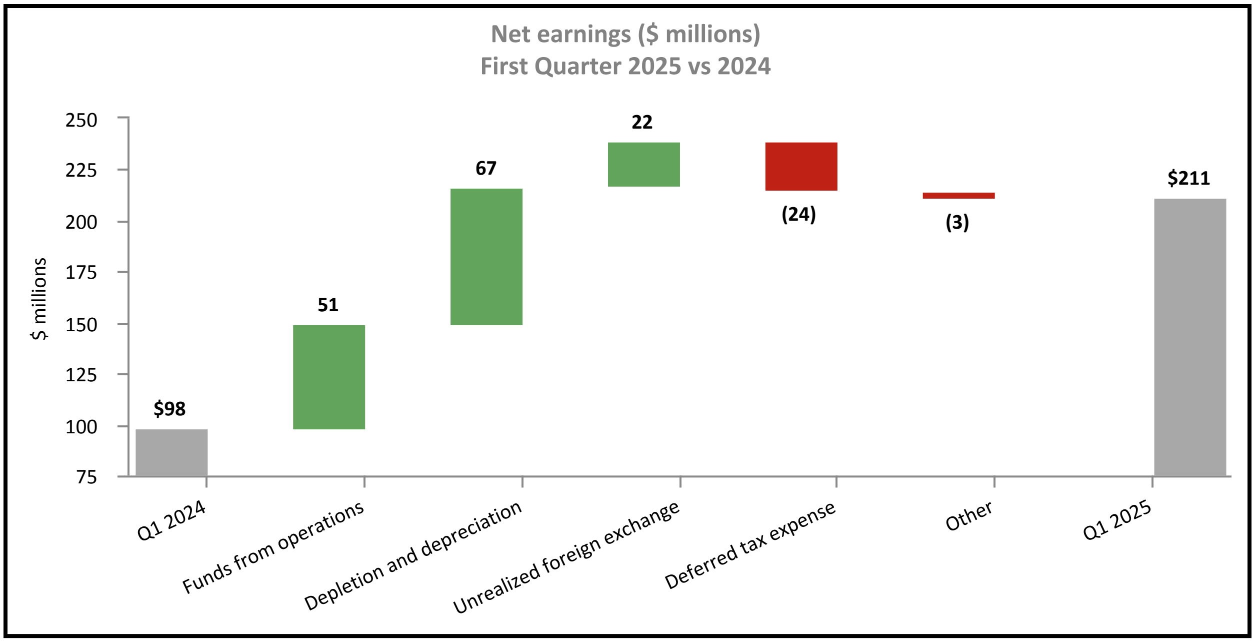
The Corporation generated free cash flow ("FCF") of $223 million in the first quarter of 2025, which was used to return $159 million to shareholders through the repurchase of 6.7 million shares, or 3% of total shares outstanding at December 31, 2024, and pay a quarterly cash dividend of $26 million.

Funds from operations ("FFO") during the first quarter of 2025 increased 16% to $380 million from $329 million in the same period of 2024. The increase mainly reflects a higher blend sales price partially offset by lower blend sales volumes and higher net transportation and storage expense. On a diluted per share basis, FFO increased 24% to $1.47 in the first quarter of 2025 from $1.19 in the comparative 2024 period reflecting the combined impact of increased FFO and share repurchases.

Average bitumen production volumes in the first quarter of 2025 were 103,224 barrels per day, at a steam-oil ratio ("SOR") of 2.28, compared to 104,088 barrels per day, at an SOR of 2.37, in the first quarter of 2024.

Capital expenditures increased to $157 million from $112 million in the first quarters of 2025 and 2024, respectively. The increase primarily reflects the planned investment in the facility expansion project ("FEP") and field and facility infrastructure costs.

2. NET EARNINGS



Net earnings increased to $211 million in the first quarter of 2025, from $98 million in the same period of 2024, driven by higher FFO, lower depletion and depreciation expense and a reduced unrealized foreign exchange loss partially offset by higher deferred income tax expense.

3. REVENUES

	Three months ended March 31	
($millions)	**2025**	**2024**
Sales from:		
Production	**$ 1,229**	$ 1,153
Purchased product[(1)]	**30**	313
Petroleum revenue	**$ 1,259**	$ 1,466
Royalties	**(108)**	(128)
Petroleum revenue, net of royalties	**$ 1,151**	$ 1,338
Power revenue	**$ 10**	$ 25
Transportation revenue	**1**	1
Power and transportation revenue	**$ 11**	$ 26
Revenues	**$ 1,162**	$ 1,364

(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 months ended March 31, 2025, petroleum revenue, net of royalties decreased to $1.2 billion from $1.3 billion in the same period of 2024. The reduction in first quarter 2025 sales from purchased product reflects lower marketing asset optimization activity as a result of improved pipeline egress, while sales from production rose due to a higher realized blend sales price partially offset by lower blend sales volumes. Royalties declined due to lower annual crude oil price estimates.

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.

4. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended March 31	
	2025	**2024**
Bitumen production – bbls/d	**103,224**	104,088
Bitumen production per share - diluted	**0.04**	0.03
Steam-oil ratio (SOR)	**2.28**	2.37

Bitumen Production

Bitumen production averaged 103,224 barrels per day during the three months ended March 31, 2025 compared to 104,088 barrels per day in the same period of 2024. First quarter of 2025 production reflects increased unplanned maintenance activities relative to the same period of 2024.

On a diluted per share basis, bitumen production increased to 0.04 barrels in the first quarter of 2025 from 0.03 barrels in the same period of 2024 reflecting share repurchases.

Steam-Oil Ratio ("SOR")

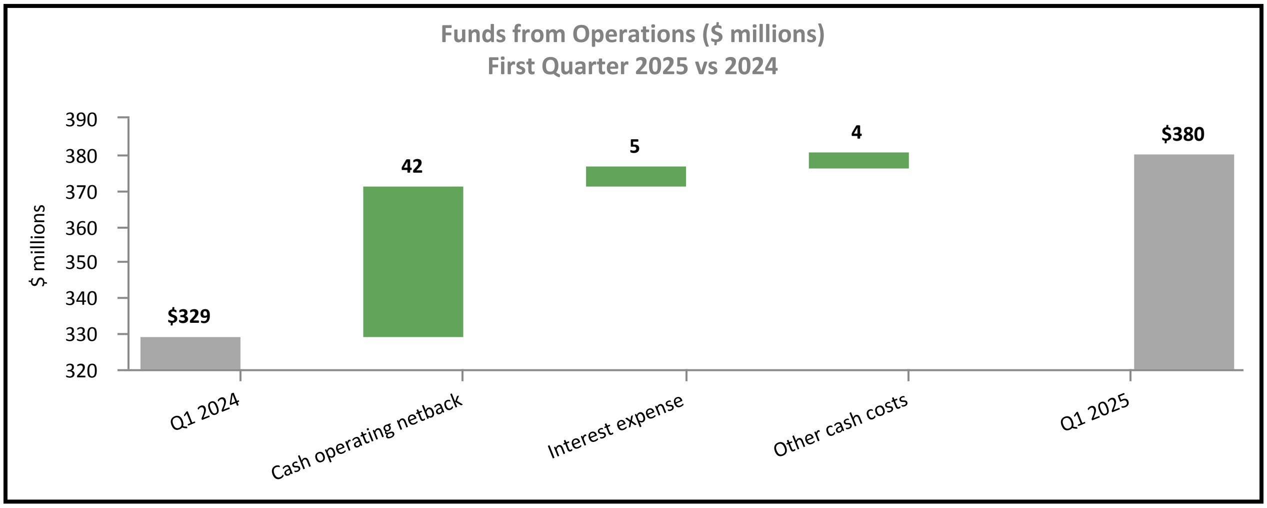
The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is SOR, which is an efficiency indicator that measures the amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR decreased approximately 4% to 2.28 in the first quarter of 2025 from 2.37 in the same period of 2024. This performance reflects improved reservoir quality and optimized design of recent wells.

Funds from Operations ("FFO") and Free Cash Flow ("FCF")

FFO and FCF are capital management measures defined in the Corporation's consolidated financial statements and both are presented to assist management and investors in analyzing operating performance and cash flow generating ability. FFO is calculated as net cash provided by (used in) operating activities before the net change in non-cash working capital items. FCF also assists management and investors in analyzing performance by the Corporation as a measure of financial liquidity and the capacity of the business to return capital to shareholders. FCF is calculated as FFO less capital expenditures.

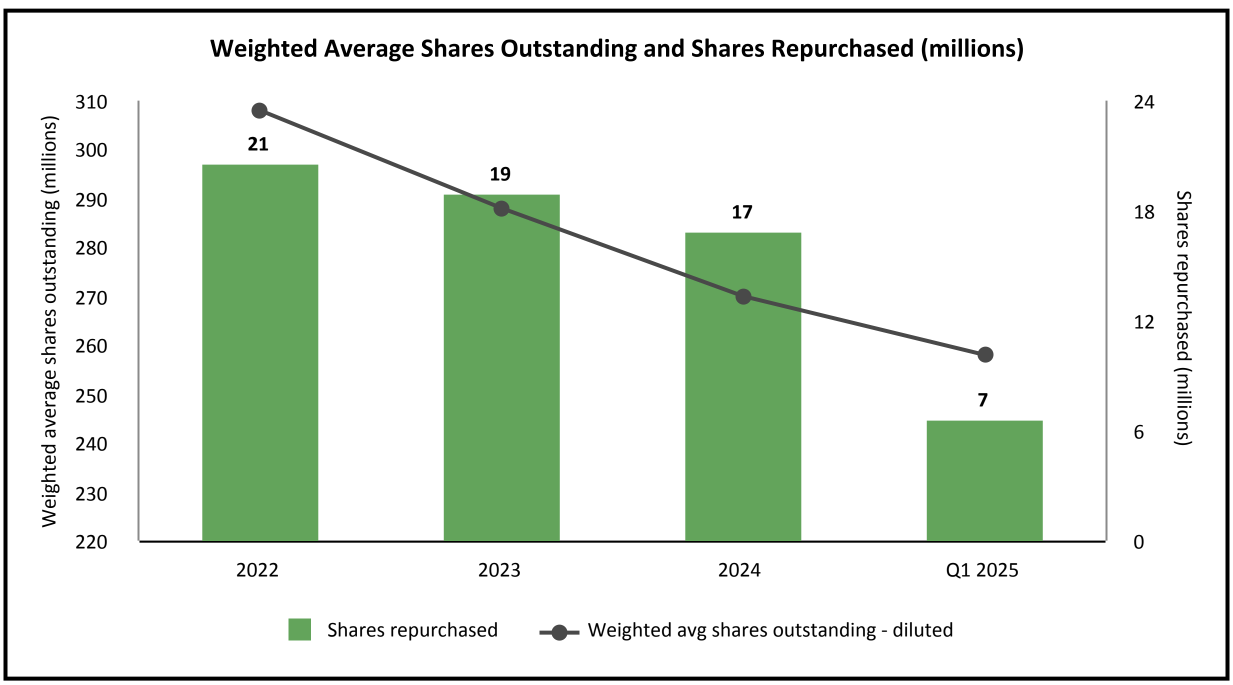
		Three months ended March 31	
($millions, except as indicated)		**2025**	**2024**
Funds from operations[(1)]	**$**	**380**	$ 329
Funds from operations per share - diluted	**$**	**1.47**	$ 1.19
Free cash flow[(1)]	**$**	**223**	$ 217
Free cash flow per share - diluted	**$**	**0.86**	$ 0.78
Weighted average shares outstanding - diluted		**258**	**276**

(1) Capital management measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.



FFO increased in the first quarter of 2025, compared to the same period of 2024, driven mainly by a higher cash operating netback and a lower interest expense due to reduced debt levels.

On a diluted per share basis, FFO increased to $1.47 per share in the first quarter of 2025 from $1.19 per share in the comparative 2024 period, reflecting the combined impact of increased FFO and share repurchases.

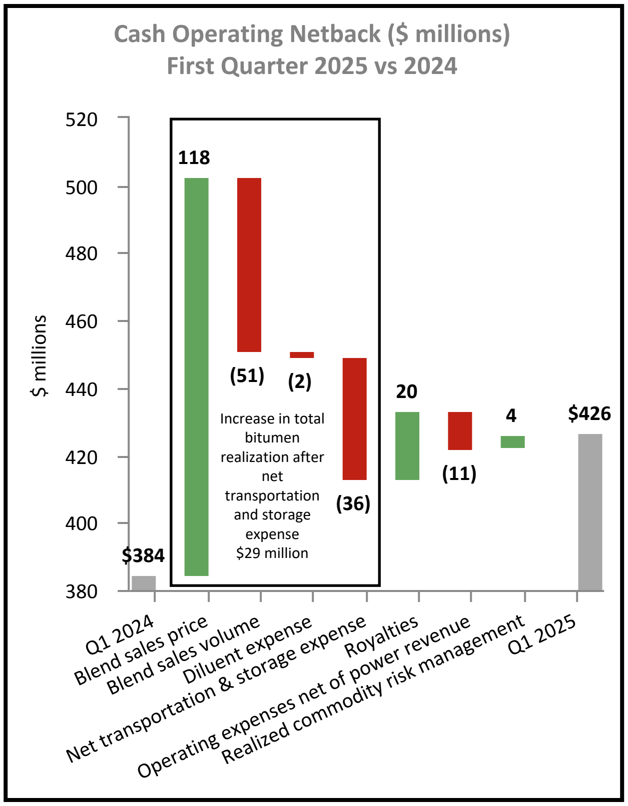


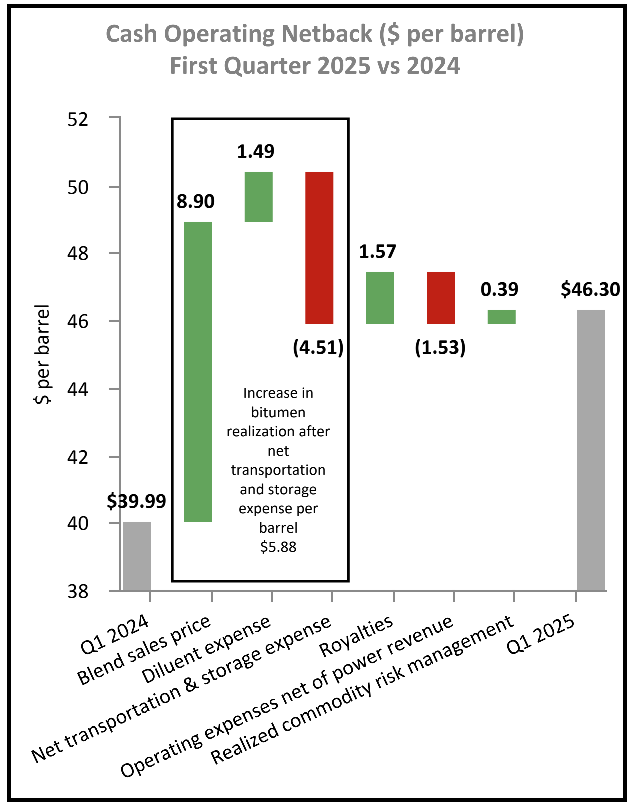
CASH OPERATING NETBACK

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

	Three months ended March 31			
	2025		2024	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Sales from production	**$ 1,229**		$ 1,153	
Sales from purchased product[1]	**30**		313	
Petroleum revenue	**$ 1,259**		$ 1,466	
Purchased product[1]	**(30)**		(304)	
Blend sales[2][3]	**$ 1,229**	**$ 92.48**	$ 1,162	$ 83.58
Diluent expense	**(458)**	**(8.51)**	(456)	(10.00)
Bitumen realization[3]	**$ 771**	**$ 83.97**	$ 706	$ 73.58
Net transportation and storage expense[3][4]	**(165)**	**(17.99)**	(129)	(13.48)
Bitumen realization after net transportation and storage expense[3]	**$ 606**	**$ 65.98**	$ 577	$ 60.10
Royalties	**(108)**	**(11.78)**	(128)	(13.35)
Operating expenses net of power revenue[3]	**(72)**	**(7.90)**	(61)	(6.37)
Realized loss on commodity risk management	**—**	**—**	(4)	(0.39)
Cash operating netback[3]	**$ 426**	**$ 46.30**	$ 384	$ 39.99
Bitumen sales volumes - bbls/d		**102,126**		105,534

(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 11 "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.





During the three months ended March 31, 2025, cash operating netback increased to $426 million from $384 million in the same period of 2024, reflecting a higher blend sales price and lower royalties, partially offset by lower blend sales volumes, higher net transportation and storage expense and increased operating expenses net of power revenue.

On a per barrel basis, cash operating netback rose to $46.30 per barrel in the first quarter of 2025 from $39.99 in the same period of 2024, mainly reflecting an increased bitumen realization after net transportation and storage expense and lower royalties partially offset by higher operating expenses net of power revenue.

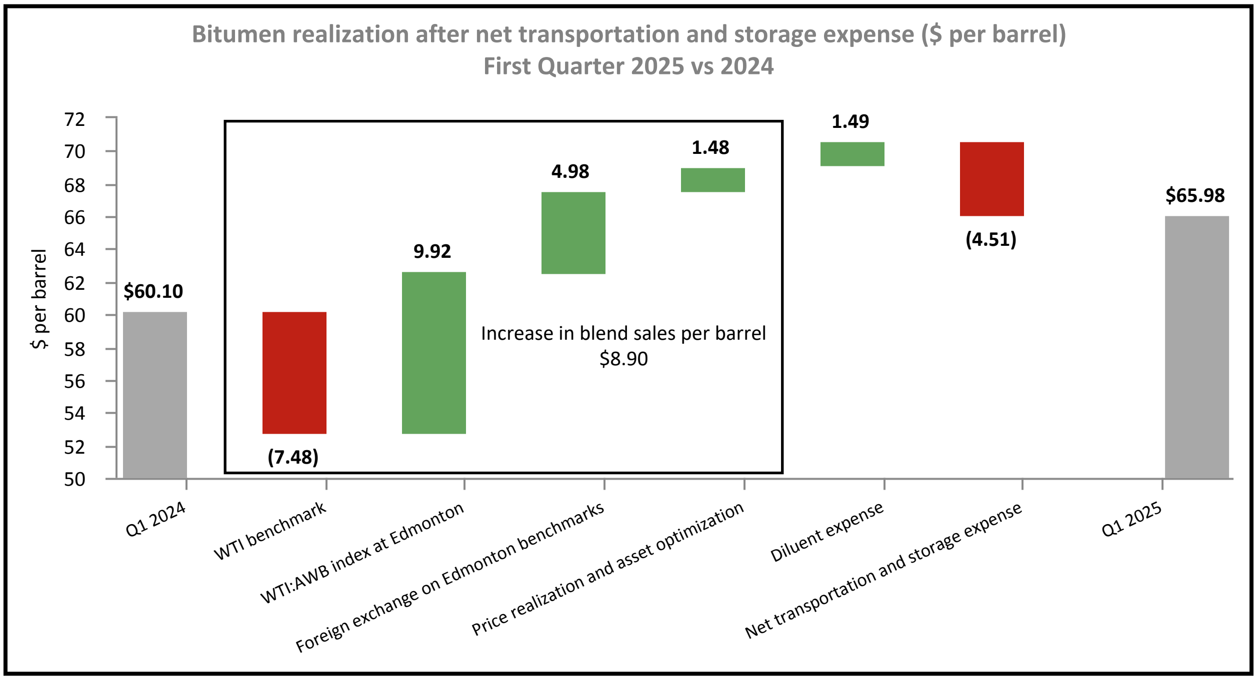
Bitumen Realization after Net Transportation and Storage Expense

Bitumen realization after net transportation and storage expense reflects the realized bitumen price 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 at the ultimate sales location 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 barrels per day of diluent is sourced from the Mont Belvieu, Texas market with the remainder from Edmonton. The cost of purchased diluent 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 the WTI price and the WTI:AWB differential.

	Three months ended March 31			
	2025		2024	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	**$ 1,229**		$ 1,153	
Sales from purchased product[1]	**30**		313	
Petroleum revenue	**$ 1,259**		$ 1,466	
Purchased product[1]	**(30)**		(304)	
Blend sales[2][3]	**$ 1,229**	**$ 92.48**	$ 1,162	$ 83.58
Diluent expense	**(458)**	**(8.51)**	(456)	(10.00)
Bitumen realization[3]	**$ 771**	**$ 83.97**	$ 706	$ 73.58
Net transportation and storage expense[3]	**(165)**	**(17.99)**	(129)	(13.48)
Bitumen realization after net transportation and storage expense	**$ 606**	**$ 65.98**	$ 577	$ 60.10
Bitumen sales volumes - bbls/d		**102,126**		105,534

(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 11 "Non-GAAP and Other Financial Measures" of this MD&A.



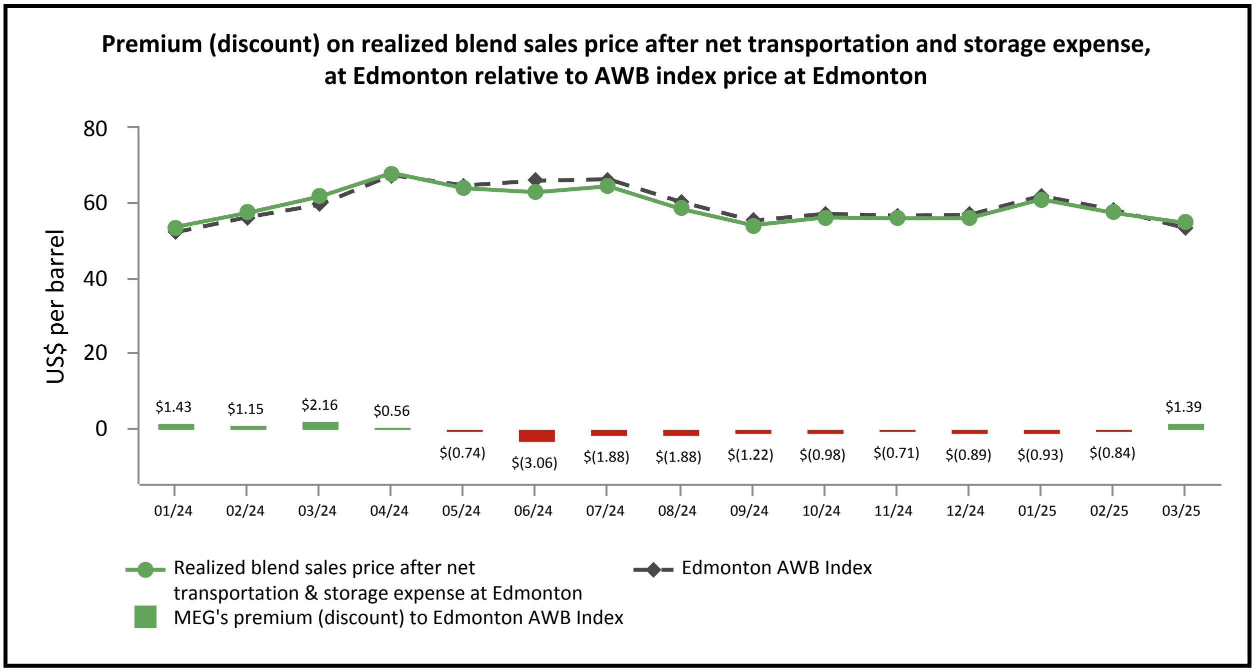
Bitumen realization after net transportation and storage expense increased 10%, to $65.98 per barrel, in the three months ended March 31, 2025, from $60.10 per barrel in the same period of 2024. The benefits from narrower WTI:AWB differentials, the positive impact of a weaker Canadian dollar, higher price realization associated with diverse market access, and lower diluent expense were partially offset by a lower average WTI price and higher net transportation and storage expense.

Diluent expense per barrel in the three months ended March 31, 2025 decreased to $8.51 from $10.00 in the same period of 2024, reflecting narrower WTI:AWB differentials partially offset by a higher average condensate price relative to WTI. As a result, the Corporation recovered 83% of diluent costs through blend sales in the three months ended March 31, 2025 compared to 79% in the same period of 2024.

	Three months ended March 31					
	2025			2024		
($millions, except as indicated)			$/bbl			$/bbl
Transportation and storage expense	$	(166) $	(18.07) $		(130) $	(13.55)
Transportation revenue		1	0.08		1	0.07
Net transportation and storage expense	$	(165) $	(17.99) $		(129) $	(13.48)
Bitumen sales volumes - bbls/d			102,126			105,534

Net transportation and storage expense in the three months ended March 31, 2025, on a total and per barrel basis, rose relative to the same period of 2024 primarily reflecting higher volumes shipped to the USGC as a result of lower pipeline apportionment and new tolls on volumes transported to the west coast of Canada on TMX.

Long-term transportation and storage assets are strategically utilized to access diverse global markets and 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 the average sales price achieved through long-term market diversification relative to local markets.



In the first quarter of 2025, the Corporation's overall average realized blend sales price after net transportation and storage expense received a discount of US$0.08 per barrel compared to the Edmonton AWB index.

Since the start-up of TMX, pipeline egress from Western Canada is unconstrained and heavy oil differentials have narrowed with anticipated lower volatility relative to historic levels. In this transportation environment, the Edmonton market will typically outperform global prices after netting transportation and storage commitments utilized by the Corporation to reach tidewater. As western Canadian production grows and egress fills, this trend is expected to reverse and the historic benefits of MEG's pipeline transportation commitments are expected to return.

Royalties

The Oil Sands Royalty Regulation, 2009, establishes royalty rates that are linked to the WTI price 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 Corporation's Christina Lake project reached payout in 2023.

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 dollar WTI price is $120 per barrel or higher. Royalties are calculated in respect of a calendar year with monthly installments paid based on annual estimates allocated by revenue.

	Three months ended March 31	
($millions)	**2025**	**2024**
Royalties	**$ 108**	$ 128
Royalty rate	**35.5 %**	35.3 %

Royalties in the first quarter of 2025 decreased 15%, compared to the same period of 2024. Royalties declined primarily due to lower annual forecasted net revenues reflecting the impact of lower crude oil price estimates for 2025 and a higher capital expenditures forecast.

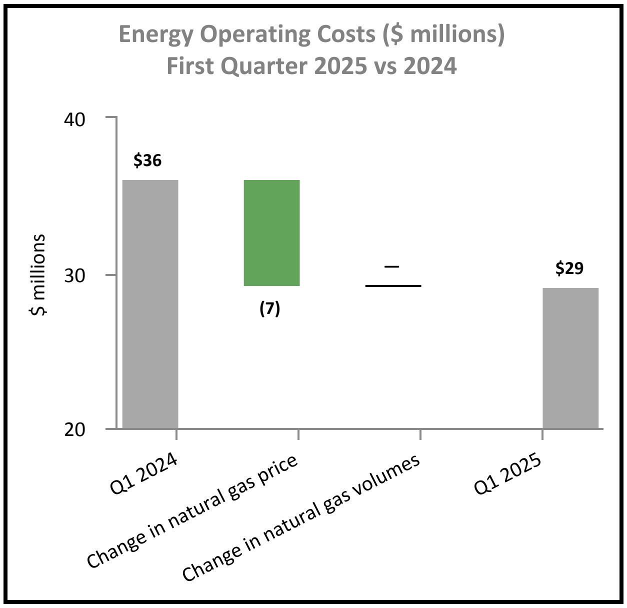
Operating Expenses net of Power Revenue

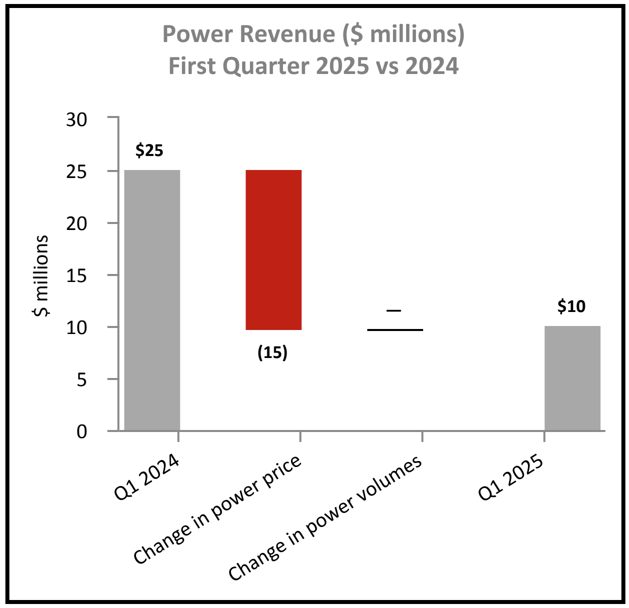
Operating expenses net of power revenue are comprised of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-oriented operating activities and energy operating costs reflect the cost of natural gas used to generate steam and power. Power revenue is recognized from the sale of surplus power generated by the Corporation's cogeneration facilities.

	Three months ended March 31			
	2025		**2024**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Non-energy operating costs[1]	**$ (53)**	**$ (5.84)**	$ (50)	$ (5.18)
Energy operating costs[1]	**(29)**	**(3.12)**	(36)	(3.74)
Operating expenses	**(82)**	**(8.96)**	(86)	(8.92)
Power revenue	**10**	**1.06**	25	2.55
Operating expenses net of power revenue[2]	**$ (72)**	**$ (7.90)**	$ (61)	$ (6.37)
Energy operating costs net of power revenue[2]	**$ (19)**	**$ (2.06)**	$ (11)	$ (1.19)
Average delivered natural gas price (C$/mcf)		**$ 2.44**		$ 3.03
Average realized power sales price (C$/Mwh)		**$ 41.31**		$ 102.53

(1) Supplementary financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Non-GAAP financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.

Total non-energy operating costs during the first quarter of 2025 increased $3 million, to $53 million, from the same period of 2024, primarily reflecting expected increases in process treating costs and services as a result of new well pads. Lower bitumen sales volumes during the first quarter of 2025, compared to the same period of 2024, further contributed to the increase on a per barrel basis.





Energy operating costs in the first quarter of 2025, on a total and per barrel basis, decreased compared to the same period of 2024 reflecting a weaker AECO natural gas price.

Power revenue in the first quarter of 2025, on a total and per barrel basis, decreased compared to the same period of 2024 reflecting a 60% decline in the realized power price.

Overall, energy operating costs net of power revenue were $2.06 per barrel in the first quarter of 2025 compared to $1.19 per barrel in the same period of 2024. Power revenue offset 34% of energy operating costs in the first quarter of 2025 compared to 69% in the comparative 2024 period.

Capital Expenditures

	Three months ended March 31	
($millions)	**2025**	**2024**
Sustaining, maintenance and other	**$ 130**	$ 112
Facility expansion project	**20**	—
Turnaround	**7**	—
	$ 157	$ 112

Capital expenditures increased to $157 million during the first quarter of 2025 from $112 million in the same period of 2024, primarily reflecting the planned investment in the facility expansion project ("FEP") and field and facility infrastructure costs.

During 2024, the Corporation reached final investment decision and approved the multi-year Christina Lake FEP which is expected to add 25,000 barrels per day of production capacity, bringing total production capacity to approximately 135,000 barrels per day in 2027, at a total estimated cost of $470 million. Progress to date is on plan. The Corporation retains the flexibility to reduce capital expenditures in response to changing market conditions, such as declining oil prices, weaker differentials, inflationary cost pressures and potential tariff impacts.

5. OUTLOOK

The Corporation's 2025 operating and capital guidance released on November 25, 2024 remains unchanged.

Summary of 2025 Guidance	
Capital expenditures	$635 million
Bitumen production - annual average	95,000 to 105,000 bbls/d
Non-energy operating costs	$5.30 to $5.80 per bbl

The annual production guidance reflects the expected startup of two new well pads in the second half of 2025, supporting increased capacity for future production, as well as an estimated 8,000 barrels per day impact from the planned second quarter turnaround.

The Corporation's $635 million capital expenditure program includes $70 million for major planned turnaround activities and $130 million for the multi-year FEP. The remaining $435 million in the 2025 capital expenditure program will be allocated to field development and infrastructure to sustain and build future production capacity.

6. BUSINESS ENVIRONMENT

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

AVERAGE BENCHMARK COMMODITY PRICE INDICES	2025	2024				2023		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Crude oil prices								
Brent (US$/bbl)	**74.92**	73.98	78.47	84.99	81.85	81.61	85.95	78.01
WTI (US$/bbl)	**71.42**	70.27	75.09	80.57	76.96	78.32	82.26	73.78
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.67)**	(12.56)	(13.55)	(13.61)	(19.31)	(21.89)	(12.91)	(15.16)
AWB – Edmonton (US$/bbl)	**57.77**	56.82	60.62	65.99	55.96	54.53	67.88	56.41
Condensate prices								
Condensate at Edmonton (C$/bbl)	**100.29**	98.86	97.10	105.56	98.18	103.90	104.62	97.19
Condensate at Edmonton as a % of WTI	**97.9**	100.6	94.8	95.7	94.6	97.4	94.8	98.1
Condensate at Mont Belvieu, Texas (US$/bbl)	**64.05**	62.86	62.06	64.96	64.52	62.28	64.90	60.54
Condensate at Mont Belvieu, Texas as a % of WTI	**89.7**	89.5	82.6	80.6	83.8	79.5	78.9	82.1
Natural gas prices								
AECO (C$/mcf)	**2.36**	1.61	0.75	1.29	2.72	2.51	2.83	2.67
Electric power prices								
Alberta power pool (C$/MWh)	**40.29**	51.73	55.23	45.28	98.87	81.76	151.18	159.87
Foreign exchange rates								
C$ equivalent of 1 US$ – average	**1.4350**	1.3991	1.3636	1.3684	1.3488	1.3618	1.3410	1.3430
C$ equivalent of 1 US$ – period end	**1.4379**	1.4405	1.3505	1.3687	1.3533	1.3205	1.3537	1.3238

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.

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 is 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 and the Canadian West Coast where it is typically sold at a discount to WTI reflecting supply/demand fundamentals for heavy sour oil in those regions.

The average WTI price decreased 7%, to US$71.42 per barrel, in the first quarter of 2025, relative to the same period of 2024. Subsequent to the first quarter of 2025, WTI prices further declined, primarily driven by an anticipated reduction in oil demand from tariffs on the global economy, exacerbated by OPEC+ announced production increases.

The WCS differential improved US$6.64 per barrel in the first quarter of 2025, relative to the comparative 2024 period, reflecting unconstrained pipeline egress, low inventories of heavy crude in Western Canada and sustained global demand for heavy crude. As a result, the AWB Edmonton index rose US$1.81 per barrel, to US$57.77 per barrel, in the first quarter of 2025, relative to the same period of 2024, reflecting tighter differentials partially offset by a lower WTI price.

Condensate Prices

In order to facilitate pipeline transportation, the Corporation uses condensate as diluent for blending with its 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 and the USGC increased as a percentage of WTI in the first quarter of 2025 compared to the same period of 2024. The increase in condensate pricing in the first quarter of 2025 reflects higher diluent demand associated with Western Canada sedimentary basin bitumen production as well as higher petrochemical feedstock demand stemming from modest growth in global manufacturing. The narrower heavy oil differential more than offset the condensate price increase and improved the recovery of diluent costs in blend sales, reducing per barrel diluent expense. The Corporation recovered 83% of diluent costs through blend sales in the three months ended March 31, 2025 compared to 79% in the same period of 2024.

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. The average AECO natural gas price decreased 13%, to $2.36 per mcf, in the first quarter of 2025, relative to the comparative 2024 period, primarily due to continued strong natural gas production in Alberta.

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 weakened 59%, to $40.29 per MWh, in the first quarter of 2025, compared to the same period of 2024, reflecting increasing penetration of renewables, start-up of several new large-scale gas fired generation units and lower natural gas prices.

7. OTHER OPERATING RESULTS

General and Administrative

	Three months ended March 31	
($millions, except as indicated)	**2025**	**2024**
General and administrative	**$ 19**	$ 20
General and administrative expense per barrel of production	**$ 2.00**	$ 2.18
Bitumen production - bbls/d	**103,224**	104,088

Depletion and Depreciation

	Three months ended March 31	
($millions, except as indicated)	**2025**	**2024**
Depletion and depreciation expense	**$ 92**	$ 159
Depletion and depreciation expense per barrel of production	**$ 9.86**	$ 16.79
Bitumen production - bbls/d	**103,224**	104,088

Depletion and depreciation expense decreased by $67 million during the three months ended March 31, 2025, compared to the same period of 2024. Effective January 1, 2025 field production assets are depleted using the unit-of-production method based on estimated proved developed bitumen reserves. Prior to January 1, 2025, field production assets were depleted using the unit-of-production method based on estimated proved bitumen reserves plus estimated future development costs to develop and produce these proved bitumen reserves. This change in estimate has been applied on a prospective basis resulting in an approximately $57 million decrease to depletion and depreciation expense during the three months ended March 31, 2025. This change in estimate better allocates costs over the remaining estimated useful lives of the field production assets.

Stock-based Compensation

	Three months ended March 31	
($millions)	**2025**	**2024**
Cash-settled expense	**$ 5**	$ 11
Equity-settled expense	**14**	7
Stock-based compensation expense	**$ 19**	$ 18

During the first quarter of 2025, the Corporation's share price increased 7% compared to 31% in the same period of 2024 and there were fewer cash-settled units outstanding on average in 2025. These factors resulted in a lower cash-settled stock-based compensation expense in the first quarter of 2025.

Equity-settled stock-based compensation expense increased $7 million in the first quarter of 2025 compared to comparative 2024 period primarily as a result of an increase in the estimated fair value of awards granted.

Foreign Exchange Gain (Loss)

	Three months ended March 31	
($millions)	**2025**	**2024**
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ 1**	$ (28)
US$ denominated cash and cash equivalents	**(1)**	6
Unrealized net gain (loss) on foreign exchange	**—**	(22)
Realized gain (loss) on foreign exchange	**—**	(1)
Foreign exchange gain (loss)	**$ —**	$ (23)

C$ equivalent of 1 US$		
Beginning of period	**1.4405**	1.3205
End of period	**1.4379**	1.3533

Foreign exchange gains (losses) reflect fluctuations in the U.S. dollar to Canadian dollar exchange rate and are primarily driven by the Corporation's U.S. dollar denominated long-term debt.

There was minimal change in the Canadian dollar exchange rate relative to the U.S. dollar in the first quarter of 2025 resulting in $nil foreign exchange gain (loss).

During the three months ended March 31, 2024, the Canadian dollar weakened relative to the U.S. dollar by 2% resulting in an unrealized foreign exchange loss of $22 million.

Net Finance Expense

	Three months ended March 31	
($millions)	**2025**	**2024**
Interest expense on long-term debt	**$ 13**	$ 19
Interest expense on lease liabilities	**6**	6
Credit facility fees	**2**	3
Interest income	**(1)**	(3)
Net interest expense	**20**	25
Debt extinguishment expense	**—**	7
Accretion on provisions	**3**	3
Net finance expense	**$ 23**	$ 35

Average effective interest rate	**5.9%**	6.2%

Interest expense on long-term debt decreased during the three months ended March 31, 2025, compared to the same period of 2024, primarily reflecting debt repayments in 2024.

During the three months ended March 31, 2024, debt extinguishment expense of $7 million was recognized on the redemption of US$105 million of the Corporation's 7.125% senior unsecured notes.

Income Tax

	Three months ended March 31	
($millions)	**2025**	**2024**
Earnings before income taxes	**$ 273**	$ 137
Effective tax rate	**23 %**	28 %
Income tax expense	**$ 62**	$ 39

At March 31, 2025, the Corporation had approximately $3.5 billion of available Canadian tax pools, including $2.1 billion of non-capital losses and $0.2 billion of capital losses, and recognized a deferred income tax liability of $422 million.

The effective tax rate for the three months ended March 31, 2024 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.

8. LIQUIDITY AND CAPITAL RESOURCES

($millions)	**March 31, 2025**	December 31, 2024
Unsecured:		
5.875% senior unsecured notes (Mar 31, 2025 - US$600 million; due 2029; December 31, 2024 - US$600 million)	**$ 863**	$ 864
Unamortized deferred debt discount and debt issue costs	**(6)**	(6)
Current and long-term debt	**857**	858
Cash and cash equivalents	**(88)**	(156)
Net debt - C$[1]	**$ 769**	$ 702
Net debt - US$[1]	**$ 535**	$ 488

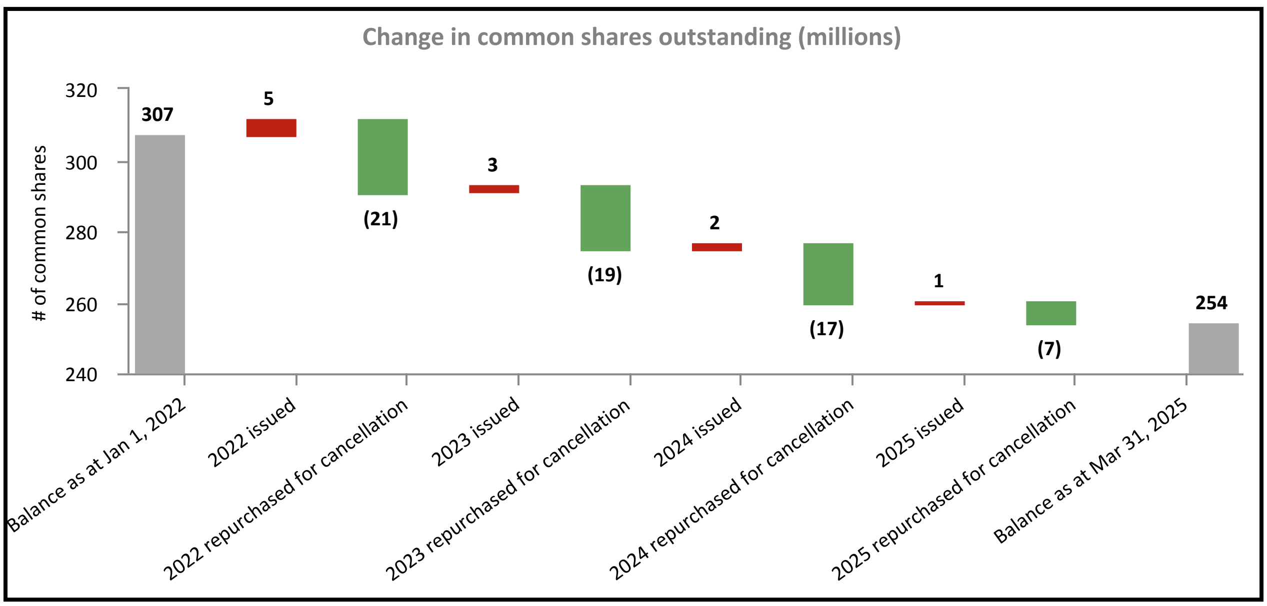
(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 22 of the interim consolidated financial statements.

The Corporation's cash and cash equivalents were $88 million at March 31, 2025 and $156 million at December 31, 2024. Refer to the "Cash Flow Summary" section for further details.

The Corporation intends to return 100% of FCF to shareholders through share repurchases and a quarterly base dividend while managing working capital cash requirements.

During the three months ended March 31, 2025, the Corporation repurchased for cancellation 6.7 million shares under its NCIB program at a weighted-average price of $23.82 per share for a total cost of $159 million.

On March 6, 2025, the Toronto Stock Exchange approved the renewal of the Corporation's normal course issuer bid ("NCIB"). Pursuant to the NCIB, the Corporation is purchasing its common shares for cancellation, from time to time, as it considers advisable, up to a maximum of 22,535,791 shares. The NCIB became effective on March 11, 2025 and will terminate on March 10, 2026 or such earlier time as the NCIB is completed or terminated at the option of MEG.



The following dividends were declared or paid in 2025:

Board of Directors Declaration Date	Shareholders of Record Date	Payment Date	Amount (C$/share)
November 5, 2024	December 16, 2024	January 15, 2025	$0.10
February 27, 2025	March 20, 2025	April 15, 2025	$0.10
May 6, 2025	June 16, 2025	July 15, 2025	$0.10

Declaration of dividends is at the discretion of the Board of Directors. Future declarations will be dependent on, among other things, the prevailing business environment, MEG’s financial and operating results and financial condition, the need for funds to finance ongoing operations or growth and other business conditions which the Corporation’s Board of Directors considers relevant.

All dividends paid by the Corporation are designated as eligible dividends for Canadian federal income tax purposes.

The Corporation has $1.2 billion of available credit, comprised of $600 million under a revolving covenant-lite credit facility and $600 million under a letter of credit facility guaranteed by Export Development Canada ("EDC Facility"). Letters of credit issued under the EDC Facility do not consume capacity of the revolving credit facility. The revolving credit facility and the EDC Facility mature on October 31, 2026 and are secured by substantially all the assets of the Corporation.

The $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 facilities, 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.

At March 31, 2025, the Corporation had $600 million of unutilized capacity under the revolving credit facility and, with $214 million of issued letters of credit, had $386 million of unutilized capacity 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.

The US$600 million of 5.875% senior unsecured notes due February 2029 represents the Corporation's only outstanding long-term debt. The outstanding debt is unsecured and contains no financial maintenance covenants.

Commodity market volatility is managed through the Corporation's various financial frameworks. Credit exposure is reduced by targeting sales to primarily investment grade customers. 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 asset development are dependent on factors discussed in the "RISK FACTORS" section of this MD&A.

Cash Flow Summary

	Three months ended March 31	
($millions)	**2025**	**2024**
Net cash provided by (used in):		
Operating activities	**$ 296**	$ 317
Investing activities	**(175)**	(119)
Financing activities	**(188)**	(279)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(1)**	6
Change in cash and cash equivalents	**$ (68)**	$ (75)

Cash Flow – Operating Activities

Net cash provided by operating activities during three months ended March 31, 2025 decreased $21 million, compared to the same period of 2024, primarily due to increased funds used for working capital requirements partially offset by higher cash operating netback.

Cash Flow – Investing Activities

Net cash used in investing activities increased $56 million during three months ended March 31, 2025, compared to the same period of 2024, primarily reflecting increased capital spending and funds used for working capital requirements.

Cash Flow – Financing Activities

Net cash used in financing activities decreased $91 million during three months ended March 31, 2025, compared to the same period of 2024, primarily reflecting decreased FCF available for share repurchases or dividends.

9. SHARES OUTSTANDING

At March 31, 2025, the Corporation had the following share capital instruments outstanding or exercisable:

(thousands)	**Units**
Common shares:	
Outstanding at December 31, 2024	260,151
Issued upon vesting and release of equity-settled RSUs and PSUs	1,334
Repurchased for cancellation	(6,659)
Common shares outstanding at March 31, 2025	**254,826**
Convertible securities:	
Equity-settled RSUs and PSUs	**2,617**

At May 5, 2025, the Corporation had 254.4 million common shares outstanding and 2.6 million equity-settled RSUs and PSUs outstanding.

10. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of obligations at March 31, 2025. 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)	2025	2026	2027	2028	2029	Thereafter	Total
Commitments:							
Transportation and storage[(1)]	$ 380	$ 506	$ 507	$ 512	$ 496	$ 4,691	$ 7,092
Diluent purchases[(2)]	188	74	65	66	65	32	490
Other operating commitments	15	19	10	9	6	58	117
Variable office lease costs	3	4	4	4	4	8	27
Capital commitments	40	—	—	—	—	—	40
Total Commitments	626	603	586	591	571	4,789	7,766
Other Obligations:							
Lease liabilities[(4)]	28	37	38	38	38	376	555
Long-term debt[(3)]	—	—	—	—	863	—	863
Interest on long-term debt[(3)]	38	51	51	51	6	—	197
Onerous contract[(4)]	8	11	11	11	3	—	44
Decommissioning obligation[(4)]	5	8	8	8	8	858	895
Total Commitments and Obligations	**$ 705**	**$ 710**	**$ 694**	**$ 699**	**$ 1,489**	**$ 6,023**	**$ 10,320**

(1) This represents transportation and storage commitments from 2025 to 2048. Excludes amounts recognized on the consolidated balance sheet.
(2) The associated transportation commitment is included in transportation and storage.
(3) 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 March 31, 2025.
(4) Represents the undiscounted future obligations associated with these liabilities.

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.

11. 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.

Funds from Operations and Free Cash Flow

Funds from operations and free cash flow are capital management measures and are defined in the Corporation's consolidated financial statements. Funds from operations and free cash flow are presented to assist management and investors in analyzing operating performance and cash flow generating ability. Net cash provided by (used in) operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Funds from operations is calculated as net cash provided by (used in) operating activities before the net change in non-cash working capital items. 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 return capital to shareholders. Free cash flow is calculated as funds from operations less capital expenditures.

The following table reconciles Net cash provided by (used in) operating activities to FFO and FCF:

	Three months ended March 31	
($millions)	**2025**	**2024**
Net cash provided by (used in) operating activities	**$ 296**	$ 317
Net change in non-cash working capital items	**$ 84**	$ 12
Funds from operations	**$ 380**	$ 329
Capital expenditures	**(157)**	(112)
Free cash flow	**$ 223**	$ 217

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, dividends, 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 and comprehensive income 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 March 31	
($millions)	**2025**	**2024**
Revenues	**$ 1,162**	$ 1,364
Diluent expense	**(458)**	(456)
Transportation and storage expense	**(166)**	(130)
Purchased product	**(30)**	(304)
Operating expenses	**(82)**	(86)
Realized loss on commodity risk management	**—**	(4)
Cash operating netback	**$ 426**	$ 384

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 measures 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 and comprehensive income, 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 March 31			
	2025		2024	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Revenues	**$ 1,162**		$ 1,364	
Power and transportation revenue	**(11)**		(26)	
Royalties	**108**		128	
Petroleum revenue	**1,259**		1,466	
Purchased product	**(30)**		(304)	
Blend sales	**1,229**	**$ 92.48**	1,162	$ 83.58
Diluent expense	**(458)**	**(8.51)**	(456)	(10.00)
Bitumen realization	**$ 771**	**$ 83.97**	$ 706	$ 73.58

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 and comprehensive income.

Power and transportation revenue is an IFRS measure in the Corporation's consolidated statement of earnings and comprehensive income, 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 March 31			
	2025		2024	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Transportation and storage expense	**$ (166)**	**$ (18.07)**	$ (130)	$ (13.55)
Power and transportation revenue	**$ 11**		$ 26	
Less power revenue	**(10)**		(25)	
Transportation revenue	**$ 1**	**$ 0.08**	$ 1	$ 0.07
Net transportation and storage expense	**$ (165)**	**$ (17.99)**	$ (129)	$ (13.48)

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 March 31			
	2025		2024	
($millions, except as indicated)		$/bbl		$/bbl
Bitumen realization[1]	**$ 771**	**$ 83.97**	$ 706	$ 73.58
Net transportation and storage expense[1]	**(165)**	**(17.99)**	(129)	(13.48)
Bitumen realization after net transportation and storage expense	**$ 606**	**$ 65.98**	$ 577	$ 60.10

(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 and comprehensive income. Power and transportation revenue is an IFRS measure in the Corporation's consolidated statement of earnings and comprehensive income 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 March 31			
	2025		2024	
($millions, except as indicated)		$/bbl		$/bbl
Non-energy operating costs	**$ (53)**	**$ (5.84)**	$ (50)	$ (5.18)
Energy operating costs	**(29)**	**(3.12)**	(36)	(3.74)
Operating expenses	**$ (82)**	**$ (8.96)**	$ (86)	$ (8.92)
Power and transportation revenue	**$ 11**		$ 26	
Less transportation revenue	**(1)**		(1)	
Power revenue	**$ 10**	**$ 1.06**	$ 25	$ 2.55
Operating expenses net of power revenue	**$ (72)**	**$ (7.90)**	$ (61)	$ (6.37)
Energy operating costs net of power revenue	**$ (19)**	**$ (2.06)**	$ (11)	$ (1.19)

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	March 31, 2025	December 31, 2024
Long-term debt	**$ 857**	$ 858
Cash and cash equivalents	**(88)**	(156)
Net debt - C$	**$ 769**	$ 702
Net debt - US$	**$ 535**	$ 488

12. 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 material accounting policies and the significant accounting estimates, assumptions and judgments can be found in the Corporation's annual audited consolidated financial statements for the year ended December 31, 2024.

Effective January 1, 2025, the Corporation made a change to the unit-of-production depletion method to better estimate the allocation of costs over the remaining estimated useful lives of certain assets. Please see note 6 of the interim consolidated financial statements for the period ended March 31, 2025 for further details.

13. RISK FACTORS

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

14. DISCLOSURE CONTROLS AND PROCEDURES

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

15. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

16. ABBREVIATIONS

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

Financial and Business Environment

AECO	Alberta natural gas price reference location
AIF	Annual Information Form
AWB	Access Western Blend
$ or C$	Canadian dollars
EDC	Export Development Canada
eMSAGP	enhanced Modified Steam And Gas Push
ESG	Environment, Social and Governance
FEP	Facility Expansion Project
FSP	Flanagan South and Seaway Pipeline
G&A	General and administrative
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse Gas
IFRS	International Financial Reporting Standards
NCIB	Normal Course Issuer Bid
MD&A	Management's Discussion and Analysis
OPEC	Organization of Petroleum Exporting Countries
OPEC+	Organization of Petroleum Exporting Countries plus an informal association of other oil producing 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

17. 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 2025 operating and capital guidance, including its expectations regarding 2025 annual average production, capital expenditures and non-energy operating costs; the breakdown of the Corporation's capital expenditures for 2025; the Corporation's expectation of the startup of two new well pads in the second half of 2025, and the impact on production in 2025 from the planned second quarter turnaround; the Corporation’s marketing strategy and marketing asset optimization strategy; the Corporation's expectation that it will benefit from its pipeline transportation commitments as western Canadian production grows and egress fills; the Corporation’s belief that its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months; the Corporation's intent to return 100% of free cash flow to shareholders through share repurchases and a quarterly base dividend, subject to approval of the Corporation's board of directors; the Corporation's belief that the FEP progress is on plan; and the Corporation’s belief that any liabilities that may accrue to the Corporation arising out of various legal claims associated with the normal course of operations would not have a material impact on the Corporation’s financial position.

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, price differentials, 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 obtain qualified staff and equipment in a timely and cost-efficient manner; 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 possibility of government production curtailment and federal and provincial climate change policies, in which the Corporation conducts and will conduct its business; 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; support for protectionism and rising anti-globalization sentiment in the United States and other countries; enacted and proposed export and import restrictions, including but not limited to tariffs, export taxes or curtailment on exports; health, safety and environmental risks, including public health crises, 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; actions taken by OPEC+ in relation to supply management; the impact of the Russian invasion of Ukraine and associated sanctions on commodity prices and the impact of other international and regional relations and other geopolitical tensions and events; 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; the impact of a cybersecurity incident; 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.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about MEG's prospective results of operations including, without limitation, the Corporation’s capital expenditures, non-energy operating costs and general and administrative costs, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on FOFI. MEG's actual results, performance or achievement could differ materially from those expressed in, or implied by, these FOFI, or if any of them do so, what benefits MEG will derive therefrom. MEG has included the FOFI in order to provide readers with a more complete perspective on MEG's future operations and such information may not be appropriate for other purposes. MEG disclaims any intention or obligation to update or revise any FOFI statements, whether as a result of new information, future events or otherwise, except as required by law.

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 the leading pure-play in situ thermal oil producer in Canada. Our purpose is to meet the growing demand for energy, produced safely and reliably, while generating long-term value for all our stakeholders. MEG produces, transports and sells our oil (AWB) to customers throughout North America and internationally. Our common shares are listed on the Toronto Stock Exchange under the symbol "MEG" (TSX: 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.

18. ADDITIONAL INFORMATION

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

19. QUARTERLY SUMMARIES

	2025	2024				2023		
Unaudited	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
FINANCIAL *($millions unless specified)*								
Net earnings	**211**	106	167	136	98	103	249	136
Per share, diluted	**0.82**	0.40	0.62	0.50	0.36	0.37	0.86	0.47
Funds from operations[(1)]	**380**	340	362	354	329	358	492	278
Per share, diluted	**1.47**	1.29	1.34	1.30	1.19	1.27	1.71	0.96
Capital expenditures	**157**	172	141	123	112	104	83	149
Free cash flow[(1)]	**223**	168	221	231	217	254	409	129
Per share, diluted	**0.86**	0.64	0.82	0.85	0.78	0.90	1.42	0.45
Working capital	**334**	300	287	344	226	278	495	231
Net debt - US$[(1)]	**535**	488	478	634	687	730	885	994
Shareholders' equity	**4,590**	4,553	4,614	4,580	4,511	4,527	4,641	4,441
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**71.42**	70.27	75.09	80.57	76.96	78.32	82.26	73.78
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.67)**	(12.56)	(13.55)	(13.61)	(19.31)	(21.89)	(12.91)	(15.16)
AWB – Edmonton (US$/bbl)	**57.77**	56.82	60.62	65.99	55.96	54.53	67.88	56.41
Mainline heavy oil pipeline apportionment	**5 %**	1 %	2 %	5 %	28 %	21 %	1 %	1 %
C$ equivalent of 1US$ – average	**1.4350**	1.3991	1.3636	1.3684	1.3488	1.3618	1.3410	1.3430
Natural gas – AECO ($/mcf)	**2.36**	1.61	0.75	1.29	2.72	2.51	2.83	2.67
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**147,715**	142,595	145,244	132,812	152,844	158,850	140,002	119,187
Diluent usage – bbls/d	**(45,589)**	(41,774)	(39,989)	(39,672)	(47,310)	(46,216)	(38,377)	(35,656)
Bitumen sales – bbls/d	**102,126**	100,821	105,255	93,140	105,534	112,634	101,625	83,531
Bitumen production – bbls/d	**103,224**	100,139	103,298	100,531	104,088	109,112	103,726	85,974
Steam-oil ratio (SOR)	**2.28**	2.40	2.36	2.44	2.37	2.28	2.28	2.25
Blend sales[(2)]	**92.48**	89.00	90.51	98.02	83.58	87.33	101.53	87.81
Diluent expense	**(8.51)**	(7.42)	(7.25)	(6.91)	(10.00)	(9.58)	(0.06)	(10.27)
Bitumen realization[(2)]	**83.97**	81.58	83.26	91.11	73.58	77.75	101.47	77.54
Net transportation and storage expense[(2)]	**(17.99)**	(18.96)	(17.65)	(17.27)	(13.48)	(14.23)	(16.72)	(19.90)
Bitumen realization after net transportation and storage expense[(2)]	**65.98**	62.62	65.61	73.84	60.10	63.52	84.75	57.64
Royalties	**(11.78)**	(14.22)	(17.45)	(19.12)	(13.35)	(17.92)	(19.45)	(7.69)
Non-energy operating costs[(3)]	**(5.84)**	(5.61)	(5.18)	(5.63)	(5.18)	(4.64)	(5.15)	(5.66)
Energy operating costs[(3)]	**(3.12)**	(2.18)	(1.70)	(2.13)	(3.74)	(3.25)	(3.42)	(3.92)
Power revenue	**1.06**	1.28	1.06	1.14	2.55	1.79	3.46	2.95
Realized loss on commodity risk management	**—**	(0.80)	(0.99)	(0.96)	(0.39)	(0.85)	(1.55)	(0.94)
Cash operating netback[(2)]	**46.30**	41.09	41.35	47.14	39.99	38.65	58.64	42.38
Revenues	**1,162**	1,147	1,265	1,373	1,364	1,444	1,438	1,291
Power sales price (C$/MWh)	**41.31**	52.21	53.64	45.57	102.53	81.66	156.04	150.19
Power sales (MW/h)	**112**	108	90	100	113	108	97	71
Average cost of diluent ($/bbl of diluent)	**111.56**	106.91	109.62	114.25	105.89	110.65	101.68	111.85
Average cost of diluent as a % of WTI	**109 %**	109 %	107 %	104 %	102 %	104 %	92 %	113 %
Depletion and depreciation rate per bbl of production	**9.86**	16.37	16.92	16.35	16.79	19.01	15.28	14.88
General and administrative expense per bbl of production	**2.00**	1.85	1.80	1.98	2.18	1.89	1.73	1.85
COMMON SHARES								
Shares outstanding, end of period (000)	**254,826**	260,151	266,035	270,142	272,376	274,642	283,290	285,566
Common share price ($) - close (end of period)	**25.23**	23.60	25.41	29.27	31.10	23.67	26.43	21.00

(1) *Capital management measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.*
(2) *Non-GAAP financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Supplementary financial measure - please refer to section 11 "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 changes in the price of WTI which ranged from a quarterly average of US$70.27/bbl to US$82.26/bbl;
- variability in WTI:WCS differential at Edmonton which ranged from a quarterly average of US$12.56/bbl to US$21.89/bbl;
- 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 in the second quarter of 2023, which impacts the Crown royalty rate and resulting royalty expense;
- reaching the US$600 million net debt target in the third quarter of 2024 allowing the Corporation to return 100% of FCF to shareholders through share repurchases and the introduction of a quarterly base dividend starting in the fourth quarter of 2024;
- changes in depletion and depreciation expense as a result of changes in production rates and future development cost estimates;
- timing of capital projects;
- inflationary pressure;
- pipeline apportionment and the ability to reach USGC and Canadian west coast markets, including the impact of the TMX start-up in the second quarter of 2024;
- fluctuations in natural gas and power pricing;
- changes to the Corporation's depletion methodology in the first quarter of 2025;
- changes in the Corporation's share price and the resulting impact on stock-based compensation; and
- planned turnaround, unplanned outages and other maintenance activities affecting production.

20. ANNUAL SUMMARIES

	2024	2023	2022	2021	2020	2019	2018[1]
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	507	569	902	283	(357)	(62)	(119)
Per share, diluted	1.87	1.98	2.92	0.91	(1.18)	(0.21)	(0.40)
Funds from operations[2]	1,385	1,476	1,882	753	239	741	169
Per share, diluted[2]	5.13	5.13	6.09	2.42	0.78	2.46	0.56
Adjusted funds flow	1,385	1,402	1,934	826	281	724	175
Per share, diluted	5.13	4.87	6.26	2.65	0.92	2.41	0.58
Capital expenditures	548	449	376	331	149	198	622
Free cash flow[2]	837	953	1,558	495	132	526	(447)
Per share, diluted[2]	3.10	3.31	5.05	1.59	0.43	1.75	(1.51)
Working capital	300	278	289	150	55	123	290
Net debt - US$[2]	488	730	1,026	1,897	2,194	2,250	2,508
Shareholders' equity	4,553	4,527	4,383	3,808	3,506	3,853	3,886
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/bbl)	75.72	77.62	94.23	67.91	39.40	57.03	64.77
Differential – WTI:WCS – Edmonton (US$/bbl)	(14.76)	(18.71)	(18.27)	(13.04)	(12.60)	(12.76)	(26.31)
AWB – Edmonton (US$/bbl)	59.84	56.83	73.59	53.20	25.08	42.08	34.78
Mainline heavy oil pipeline apportionment	9 %	9 %	5 %	42 %	24 %	43 %	41 %
C$ equivalent of 1US$ – average	1.3700	1.3495	1.3016	1.2536	1.3413	1.3269	1.2962
Natural gas – AECO ($/mcf)	1.59	2.88	5.79	3.95	2.43	1.92	1.62
OPERATIONAL **($/bbl unless specified)**							
Blend sales, net of purchased product – bbls/d	143,377	143,063	135,873	131,659	118,347	134,223	125,368
Diluent usage – bbls/d	(42,179)	(41,977)	(40,182)	(39,521)	(35,626)	(40,637)	(38,317)
Bitumen sales – bbls/d	101,198	101,086	95,691	92,138	82,721	93,586	87,051
Bitumen production – bbls/d	102,012	101,425	95,338	93,733	82,441	93,082	87,731
Steam-oil ratio (SOR)	2.39	2.27	2.36	2.43	2.32	2.22	2.19
Blend sales[3]	90.02	87.94	102.02	72.20	37.65	61.29	53.47
Diluent expense	(7.90)	(9.30)	(10.07)	(9.73)	(10.42)	(8.08)	(16.78)
Bitumen realization[3]	82.12	78.64	91.95	62.47	27.23	53.21	36.69
Net transportation and storage expense[3]	(16.81)	(16.18)	(15.29)	(10.93)	(12.92)	(10.84)	(8.42)
Bitumen realization after net transportation & storage expense[3]	65.31	62.46	76.66	51.54	14.31	42.37	28.27
Curtailment	—	—	—	—	0.06	(0.37)	—
Royalties	(15.96)	(12.37)	(6.43)	(2.25)	(0.31)	(1.30)	(1.20)
Non-energy operating costs[4]	(5.39)	(5.01)	(4.73)	(4.24)	(4.38)	(4.61)	(4.62)
Energy operating costs[4]	(2.45)	(4.03)	(7.29)	(4.94)	(3.29)	(2.38)	(1.98)
Power revenue	1.52	3.08	4.11	2.58	1.49	1.75	1.51
Realized gain (loss) on commodity risk management	(0.78)	(0.77)	0.29	(9.32)	11.34	(3.31)	(4.37)
Cash operating netback[3]	42.25	43.36	62.61	33.37	19.22	32.15	17.61
Revenues	5,149	5,653	6,118	4,321	2,292	3,931	2,733
Power sales price (C$/MWh)	64.64	136.50	162.33	90.10	47.81	56.70	47.87
Power sales (MW/h)	103	98	104	115	108	121	114
Average cost of diluent ($/bbl of diluent)	108.99	110.34	126.00	94.88	61.86	79.89	91.60
Average cost of diluent as a % of WTI	105 %	105 %	103 %	111 %	117 %	106 %	109 %
Depletion and depreciation rate per bbl of production	16.61	16.10	14.57	13.15	13.60	20.90	14.12
General and administrative expense per bbl of production	1.95	1.86	1.78	1.65	1.62	1.99	2.58
COMMON SHARES							
Shares outstanding, end of period (000)	260,151	274,642	291,081	306,865	302,681	299,508	296,841
Common share price ($) - close (end of period)	23.60	23.67	18.85	11.70	4.45	7.39	7.71

(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 11 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Non-GAAP financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.*
(4) *Supplementary financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.*

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

As at	Note	March 31, 2025	December 31, 2024
Assets			
Current assets			
Cash and cash equivalents	19	$ **88**	$ 156
Accrued revenue and accounts receivable	4	**452**	440
Inventories	5	**275**	258
		815	854
Non-current assets			
Property, plant and equipment	6	**5,598**	5,556
Exploration and evaluation assets	7	**128**	128
Other assets	8	**206**	206
Total assets		$ **6,747**	$ 6,744
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	9	$ **409**	$ 471
Dividends payable	12	**26**	26
Interest payable		**9**	22
Current portion of provisions and other liabilities	11	**37**	35
		481	554
Non-current liabilities			
Long-term debt	10	**857**	858
Provisions and other liabilities	11	**397**	417
Deferred income tax liability		**422**	362
Total liabilities		**2,157**	2,191
Shareholders' equity			
Share capital	13	**4,481**	4,571
Contributed surplus		**164**	176
Deficit		**(103)**	(242)
Accumulated other comprehensive income		**48**	48
Total shareholders' equity		**4,590**	4,553
Total liabilities and shareholders' equity		$ **6,747**	$ 6,744

Commitments and contingencies (Note 23)
The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

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

Three Months Ended March 31	Note	2025	2024
Revenues			
Petroleum revenue, net of royalties	15	**$ 1,151**	$ 1,338
Power and transportation revenue	15	**11**	26
Revenues		**1,162**	1,364
Expenses			
Diluent expense		**458**	456
Transportation and storage expense		**166**	130
Operating expenses		**82**	86
Purchased product		**30**	304
Depletion and depreciation	6	**92**	159
General and administrative		**19**	20
Stock-based compensation	14	**19**	18
Net finance expense	17	**23**	35
Other income		**—**	(4)
Foreign exchange loss	16	**—**	23
Earnings before income taxes		**273**	137
Income tax expense	18	**62**	39
Net earnings		**211**	98
Other comprehensive income, net of tax			
Items that may be reclassified to profit or loss:			
Foreign currency translation adjustment		**—**	5
Comprehensive income		**$ 211**	$ 103
Net earnings per common share			
Basic	20	**$ 0.82**	$ 0.36
Diluted	20	**$ 0.82**	$ 0.36

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

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

	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2024	**$ 4,571**	**$ 176**	**$ (242)**	**$ 48**	**$ 4,553**
Stock-based compensation	**—**	**14**	**—**	**—**	**14**
RSUs and PSUs vested and released	**26**	**(26)**	**—**	**—**	**—**
Repurchase of shares for cancellation	**(116)**	**—**	**(43)**	**—**	**(159)**
Tax on repurchases of equity	**—**	**—**	**(3)**	**—**	**(3)**
Dividends	**—**	**—**	**(26)**	**—**	**(26)**
Comprehensive income	**—**	**—**	**211**	**—**	**211**
Balance as at March 31, 2025	**$ 4,481**	**$ 164**	**$ (103)**	**$ 48**	**$ 4,590**

	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2023	$ 4,845	$ 180	$ (531)	$ 33	$ 4,527
Stock-based compensation	—	7	—	—	7
Stock options exercised	1	—	—	—	1
RSUs vested and released	23	(23)	—	—	—
Repurchase of shares for cancellation	(83)	—	(44)	—	(127)
Comprehensive income	—	—	98	5	103
Balance as at March 31, 2024	$ 4,786	$ 164	$ (477)	$ 38	$ 4,511

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

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

Three Months Ended March 31	Note	2025	2024
Cash provided by (used in):			
Operating activities			
Net earnings		**$ 211**	$ 98
Adjustments for:			
Deferred income tax expense	18	**62**	38
Depletion and depreciation	6	**92**	159
Stock-based compensation	14	**14**	7
Unrealized loss (gain) on foreign exchange	16	**—**	22
Unrealized net loss (gain) on commodity risk management	21	**—**	(4)
Debt extinguishment expense	17	**—**	7
Accretion on provisions	11	**3**	3
Other		**—**	(2)
Decommissioning expenditures	11	**(2)**	(2)
Payments on onerous contract	11	**(3)**	—
Net change in long-term incentive compensation liability	11	**3**	3
Net change in non-cash working capital items	19	**(84)**	(12)
Net cash provided by (used in) operating activities		**296**	317
Investing activities			
Capital expenditures	6	**(157)**	(112)
Net change in non-cash working capital items	19	**(18)**	(7)
Net cash provided by (used in) investing activities		**(175)**	(119)
Financing activities			
Repurchase and redemption of long-term debt		**—**	(142)
Debt redemption premium		**—**	(4)
Repurchase of shares	13	**(159)**	(127)
Tax on share repurchases	13	**(3)**	—
Issue of shares, net of issue costs		**—**	1
Receipts on leased assets	19	**—**	1
Payments on leased liabilities	19	**(5)**	(4)
Payments of dividends	12	**(26)**	—
Net change in non-cash working capital items	19	**5**	(4)
Net cash provided by (used in) financing activities		**(188)**	(279)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(1)**	6
Change in cash and cash equivalents		**(68)**	(75)
Cash and cash equivalents, beginning of year		**156**	160
Cash and cash equivalents, end of period		**$ 88**	$ 85

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

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange under the symbol "MEG". The Corporation owns a 100% interest in over 410 square miles of mineral leases in the southern Athabasca oil region of Alberta, Canada and is primarily engaged in *in situ* thermal oil production at its Christina Lake Project.

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

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements ("interim consolidated financial statements") were prepared using the same accounting policies and methods as those used in the Corporation's audited consolidated financial statements for the year ended December 31, 2024, unless otherwise noted. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting ("IAS 34"). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards"), has been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 4 of the Corporation's audited consolidated financial statements for the year ended December 31, 2024. These interim consolidated financial statements should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2024.

Effective January 1, 2025, the Corporation made a change to the unit-of-production depletion method to better estimate the allocation of costs over the remaining estimated useful lives of certain assets. Please see note 6 of these interim consolidated financial statements for further details.

These interim consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation's functional currency and were approved by the Corporation's Board of Directors on May 6, 2025.

3. CHANGE IN ACCOUNTING POLICY

New accounting standards

IFRS 18 *Presentation and Disclosure in Financial Statements*

IFRS 18 ‘Presentation and Disclosure in Financial Statements’ was issued on April 9, 2024 by the International Accounting Standards Board effective for annual periods beginning on or after January 1, 2027. The standard is to be applied retrospectively, with certain transition provisions. The standard introduces new requirements for improved comparability in the structure of the statement of earnings and comprehensive income, enhanced transparency of management-defined performance measures and more useful grouping of information in the financial statements. The Corporation is currently evaluating the impacts of the standard on its consolidated financial statements.

4. ACCRUED REVENUE AND ACCOUNTS RECEIVABLE

As at	March 31, 2025	December 31, 2024
Accrued revenue	**$ 418**	$ 411
Accounts receivable	**11**	9
Deposits and advances	**22**	19
Current portion of sublease receivable	**1**	1
	$ 452	$ 440

5. INVENTORIES

As at	March 31, 2025	December 31, 2024
Bitumen blend	**$ 239**	$ 221
Diluent	**18**	17
Material and supplies	**18**	20
	$ 275	$ 258

6. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Right-of-use assets	Corporate assets	Total
Cost				
Balance as at December 31, 2023	$ 10,396	$ 308	$ 79	$ 10,783
Additions	548	7	—	555
Derecognition	(11)	—	—	(11)
Change in decommissioning provision	(56)	—	—	(56)
Balance as at December 31, 2024	$ 10,877	$ 315	$ 79	$ 11,271
Additions	157	—	—	157
Change in decommissioning provision	(14)	—	—	(14)
Balance as at March 31, 2025	**$ 11,020**	**$ 315**	**$ 79**	**$ 11,414**
Accumulated depletion and depreciation				
Balance as at December 31, 2023	$ 4,954	$ 85	$ 61	$ 5,100
Depletion and depreciation	603	19	4	626
Derecognition	(11)	—	—	(11)
Balance as at December 31, 2024	$ 5,546	$ 104	$ 65	$ 5,715
Depletion and depreciation	96	4	1	101
Balance as at March 31, 2025	**$ 5,642**	**$ 108**	**$ 66**	**$ 5,816**
Carrying amounts				
Balance as at December 31, 2024	$ 5,331	$ 211	$ 14	$ 5,556
Balance as at March 31, 2025	**$ 5,378**	**$ 207**	**$ 13**	**$ 5,598**

At March 31, 2025, PP&E was assessed for indicators of impairment and none were identified. Assets under construction and not available for use as at March 31, 2025 totaled $74 million (as at December 31, 2024 - $44 million).

Effective January 1, 2025, field production assets are depleted using the unit-of-production method based on estimated proved developed bitumen reserves. Prior to January 1, 2025, field production assets were depleted using the unit-of-production method based on estimated proved bitumen reserves plus estimated future development costs to develop and produce these proved bitumen reserves. This change in estimate has been applied on a prospective basis resulting in an approximately $57 million decrease to depletion and depreciation expense during the three months ended March 31, 2025. This change in estimate better allocates costs over the remaining estimated useful lives of the field production assets.

7. EXPLORATION AND EVALUATION ASSETS

As at March 31, 2025, E&E assets consist of $128 million in exploration projects which are pending the determination of proved or probable bitumen reserves (year ended December 31, 2024 – $128 million). These assets were assessed for indicators of impairment at March 31, 2025 and none were identified.

8. OTHER ASSETS

As at	March 31, 2025	December 31, 2024
Non-current pipeline linefill[(a)]	**$ 190**	$ 189
Finance sublease receivables	**8**	8
Prepaid transportation costs	**7**	7
Intangible assets	**2**	3
	207	207
Less current portion, included in accrued revenue and accounts receivable	**(1)**	(1)
	$ 206	$ 206

a. Non-current pipeline linefill on third-party owned pipelines is classified as a non-current asset as these transportation contracts expire after December 2029.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at	March 31, 2025	December 31, 2024
Trade payables and other	**$ 391**	$ 455
Current liability for cash-settled stock-based compensation	**18**	16
	$ 409	$ 471

10. LONG-TERM DEBT

As at	March 31, 2025	December 31, 2024
5.875% senior unsecured notes (March 31, 2025 - US$600 million; due 2029; December 31, 2024 - US$600 million)	**863**	864
Less unamortized deferred debt discount and debt issue costs	**(6)**	(6)
	$ 857	$ 858

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.4379 (December 31, 2024 – US$1 = C$1.4405).

11. PROVISIONS AND OTHER LIABILITIES

As at		March 31, 2025		December 31, 2024
Lease liabilities[(a)]	$	242	$	247
Decommissioning provision[(b)]		147		161
Onerous contract[(c)]		40		42
Long-term incentive compensation liability		5		2
Provisions and other liabilities		434		452
Less current portion		(37)		(35)
Non-current portion	$	397	$	417

a. Lease liabilities:

As at		March 31, 2025		December 31, 2024
Balance, beginning of period	$	247	$	259
Payments		(11)		(40)
Interest expense		6		25
Foreign exchange impact		—		3
Balance, end of period		242		247
Less current portion		(16)		(16)
Non-current portion	$	226	$	231

The Corporation's minimum lease payments are as follows:

As at March 31		2025
Within one year	$	38
Later than one year but not later than five years		154
Later than five years		370
Minimum lease payments		562
Amounts representing finance charges		(320)
Net minimum lease payments	$	242

b. Decommissioning provision:

The following table presents the decommissioning provision associated with the reclamation and abandonment of the Corporation’s PP&E and E&E assets:

As at		March 31, 2025		December 31, 2024
Balance, beginning of period	$	161	$	210
Changes in estimated life and estimated future cash flows		1		(41)
Changes in discount rates		(15)		(15)
Liabilities settled		(2)		(5)
Accretion		2		12
Balance, end of period		147		161
Less current portion		(10)		(8)
Non-current portion	$	137	$	153

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's PP&E and E&E assets. The total undiscounted amount of the estimated future cash flows to settle the decommissioning obligations is $895 million (December 31, 2024 – $898 million). At March 31, 2025, the Corporation estimated the net present value of the decommissioning obligations using a weighted-average credit-adjusted risk-free rate of 9.0% (December 31, 2024 – 8.5%) and an inflation rate of 2.1% (December 31, 2024 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2024 - periods up to the year 2066).

c. Onerous contract:

As at	March 31, 2025	December 31, 2024
Balance, beginning of period	**$ 42**	$ 47
Modification	**—**	(3)
Payments	**(3)**	(8)
Accretion	**1**	2
Foreign exchange impact	**—**	4
Balance, end of period	**40**	42
Less current portion	**(11)**	(11)
Non-current portion	**$ 29**	$ 31

The onerous contract liability represents the present value of the estimated future cash flows with a remaining term of 4 years and relates to the assignment of an onerous marketing contract.

12. DIVIDENDS

On July 25, 2024, the Board of Directors approved the initiation of a base dividend program with the intent to pay a cash dividend each quarter, subject to Board of Directors' approval. Dividends are recognized as a reduction to retained earnings when declared. The declaration of dividends is at the sole discretion of the Corporation's Board of Directors.

Board of Directors Declaration Date	Shareholders of Record Date	Payment Date	Amount (C$/share)
November 5, 2024	December 16, 2024	January 15, 2025	$0.10
February 27, 2025	March 20, 2025	April 15, 2025	$0.10
May 6, 2025	June 16, 2025	July 15, 2025	$0.10

13. SHARE CAPITAL

Common shares are classified as equity. Transaction costs directly attributable to the issuance of shares are recognized as a reduction of shareholders' equity, net of any related income tax. When the Corporation repurchases its own common shares, share capital is reduced by the average carrying value of the shares repurchased. If the average carrying value of the shares exceeds the purchase price, the difference will be recognized as contributed surplus. If the purchase price exceeds the average carrying value of the shares, any previous contributed surplus related to such transactions is reversed. To the extent there is none, the difference is recognized as a reduction to retained earnings.

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

Changes in issued common shares and the amount of share capital are as follows:

	Three months ended March 31, 2025		Year ended December 31, 2024	
	Number of shares (thousands)	Amount	Number of shares (thousands)	Amount
Balance, beginning of year	**260,151**	**$ 4,571**	274,642	$ 4,845
Issued upon exercise of stock options	**—**	**—**	155	1
Issued upon vesting and release of equity-settled RSUs and PSUs	**1,334**	**26**	2,311	23
Repurchase of shares for cancellation	**(6,659)**	**(116)**	(16,957)	(298)
Balance, end of period	**254,826**	**$ 4,481**	260,151	$ 4,571

On March 6, 2025, the Toronto Stock Exchange ("TSX") approved the renewal of the Corporation's normal course issuer bid ("NCIB"). Pursuant to the NCIB, MEG will purchase for cancellation, from time to time, as it considers advisable, up to a maximum of 22,535,791 common shares of the Corporation. The NCIB became effective on March 11, 2025 and will terminate on March 10, 2026 or such earlier time as the NCIB is completed or terminated at the option of MEG.

For the three months ended March 31, 2025, the Corporation repurchased for cancellation 6.7 million common shares under its NCIB at a weighted-average price of $23.82 per share for a total cost of $159 million. Share capital was reduced by $116 million, reflecting the average carrying value of $17.56 per share. Retained earnings was reduced by $43 million for the repurchase price of shares above the carrying value. A 2% tax levied on share repurchases totaling $3 million was also recorded as a reduction to retained earnings.

14. STOCK-BASED COMPENSATION

Three months ended March 31	2025	2024
Cash-settled expense	**$ 5**	$ 11
Equity-settled expense	**14**	7
Stock-based compensation	**$ 19**	$ 18

As at March 31, 2025, the Corporation recognized a current liability of $18 million relating to the fair value of cash-settled deferred share units (“DSUs”) (March 31, 2024 - $33 million) which is included within accounts payable and accrued liabilities and a non-current liability of $5 million relating to the fair value of cash-settled performance share units (“PSUs”) (March 31, 2024 - $3 million) which is included within provisions and other liabilities.

15. REVENUES

Three months ended March 31	2025	2024
Sales from:		
Production	$ 1,229	$ 1,153
Purchased product[(i)]	30	313
Petroleum revenue	$ 1,259	$ 1,466
Royalties	(108)	(128)
Petroleum revenue, net of royalties	$ 1,151	$ 1,338
Power revenue	$ 10	$ 25
Transportation revenue	1	1
Power and transportation revenue	$ 11	$ 26
Revenues	$ 1,162	$ 1,364

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

a. Disaggregation of revenue from contracts with customers

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

	Three months ended March 31					
	2025			2024		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	$ 409	$ 22	$ 431	$ 541	$ 43	$ 584
United States	820	8	828	612	270	882
	$ 1,229	$ 30	$ 1,259	$ 1,153	$ 313	$ 1,466

For the three months ended March 31, 2025, power and transportation revenue of $11 million was attributed to Canada (three months ended March 31, 2024 – $26 million attributed to Canada).

b. Revenue-related assets

The Corporation has recognized the following revenue-related assets in accrued revenue and accounts receivable:

As at	March 31, 2025	December 31, 2024
Petroleum revenue	$ 415	$ 409
Power and transportation revenue	3	2
Total revenue-related assets	$ 418	$ 411

Revenue-related receivables are typically settled within 30 days. At March 31, 2025 and December 31, 2024, there was no material expected credit loss recorded against revenue-related receivables.

16. FOREIGN EXCHANGE (GAIN) LOSS

Three months ended March 31	2025	2024
Unrealized foreign exchange (gain) loss on:		
Long-term debt	$ (1)	$ 28
US$ denominated cash and cash equivalents	1	(6)
Unrealized net (gain) loss on foreign exchange	—	22
Realized (gain) loss on foreign exchange	—	1
Foreign exchange (gain) loss	$ —	$ 23

C$ equivalent of 1 US$		
Beginning of period	1.4405	1.3205
End of period	1.4379	1.3533

17. NET FINANCE EXPENSE

Three months ended March 31	2025	2024
Interest expense on long-term debt	$ 13	$ 19
Interest expense on lease liabilities	6	6
Credit facility fees	2	3
Interest income	(1)	(3)
Net interest expense	20	25
Debt extinguishment expense	—	7
Accretion on provisions	3	3
Net finance expense	$ 23	$ 35

During the three months ended March 31, 2024, debt extinguishment expense of $7 million was recognized on the 7.125% senior unsecured note redemptions.

18. INCOME TAX EXPENSE

Three months ended March 31	2025	2024
Current income tax expense	$ —	$ 1
Deferred income tax expense	62	38
Income tax expense	$ 62	$ 39

19. SUPPLEMENTAL CASH FLOW DISCLOSURES

Three months ended March 31		2025		2024
Cash provided by (used in):				
Accrued revenue and accounts receivable	**$**	**(13)**	$	14
Inventories		**(9)**		(1)
Accounts payable and accrued liabilities		**(62)**		(17)
Interest payable		**(13)**		(19)
	$	**(97)**	$	(23)
Changes in non-cash working capital relating to:				
Operating	**$**	**(84)**	$	(12)
Investing		**(18)**		(7)
Financing		**5**		(4)
	$	**(97)**	$	(23)
Cash and cash equivalents:[a]				
Cash	**$**	**88**	$	85
Cash equivalents		**—**		—
	$	**88**	$	85
Cash interest paid	**$**	**25**	$	37

a. As at March 31, 2025, $69 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (March 31, 2024 – $74 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.4379 (March 31, 2024 – US$1 = C$1.3533).

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

		Finance sublease receivables		Lease liabilities		Long-term debt
Balance as at December 31, 2024	$	8	$	247	$	858
Financing cash flow changes:						
Payments on leased liabilities		**—**		**(5)**		**—**
Other cash and non-cash changes:						
Interest payments on lease liabilities		**—**		**(6)**		**—**
Interest expense on lease liabilities		**—**		**6**		**—**
Unrealized loss on foreign exchange		**—**		**—**		**(1)**
Balance as at March 31, 2025	**$**	**8**	**$**	**242**	**$**	**857**

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

20. NET EARNINGS PER COMMON SHARE

Three months ended March 31	2025	2024
Net earnings	$ 211	$ 98
Weighted average common shares outstanding (millions)[(a)]	256	273
Dilutive effect of stock options and equity-settled RSUs and PSUs (millions)	2	3
Weighted average common shares outstanding – diluted (millions)	258	276
Net earnings per share, basic	$ 0.82	$ 0.36
Net earnings per share, diluted	$ 0.82	$ 0.36

a. Weighted average common shares outstanding for the three months ended March 31, 2025 include 105,643 PSUs vested but not yet released (three months ended March 31, 2024 - 397,671 PSUs vested but not yet released).

21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

a. Fair values:

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

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

As at	March 31, 2025		December 31, 2024	
	Carrying amount	Fair value	Carrying amount	Fair value
Financial liabilities				
Long-term debt (Note 10)	$ 863	$ 843	$ 864	$ 841

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker. The fair value was determined based on estimates at March 31, 2025 and is expected to fluctuate over time.

b. Risk management:

All risk management contracts expired at the end of 2024, and the Corporation does not have any outstanding risk management assets or liabilities in 2025.

As at March 31	2025	2024
Risk management assets (liabilities), beginning of year	$ —	$ (22)
Realized risk management (gain) loss on:		
Commodity risk management contracts	—	4
Risk management assets (liabilities), end of period	$ —	$ (18)

c. Credit risk management:

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward-looking information to determine the appropriate loss allowance provisions. Credit risk exposure is mitigated through credit policies governing the Corporation’s credit portfolio and with credit practices that limit transactions according to each counterparty's credit quality. A substantial portion of accounts receivable are with investment grade customers in the energy industry and are subject to normal industry credit risk. The Corporation has experienced no material loss in relation to trade receivables. At March 31, 2025, the Corporation’s estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $451 million. Counterparty default risk associated with the Corporation’s commodity risk management activities is also partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements.

The Corporation’s cash balances are used to repay debt, fund capital expenditures and return capital to shareholders. The cash balances are held in high interest savings accounts or are invested in high grade, liquid, short-term instruments such as commercial paper, money market deposits or similar instruments. The cash and cash equivalents balance at March 31, 2025 was $88 million, which is the estimated maximum exposure to credit risk related to its cash and cash equivalents.

d. Liquidity risk management:

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

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

The US$600 million of 5.875% senior unsecured notes due February 2029 represents the earliest and only long-term debt maturity and does not contain financial maintenance covenants. Additionally, the Corporation's modified covenant-lite $600 million revolving credit facility has no financial maintenance covenant unless drawn in excess of 50%, or $300 million. If drawn in excess of 50%, or $300 million, the Corporation is required to maintain a quarterly first lien net leverage ratio (first lien net debt to last twelve-month EBITDA) of 3.5 or less. Under the Corporation's credit facility, first lien net debt is calculated as debt under the credit facility plus other debt that is secured on a *pari passu* basis with the credit facility, less cash on hand.

22. CAPITAL MANAGEMENT

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

The Corporation intends to return 100% of free cash flow ("FCF") to shareholders through share repurchases and a quarterly base dividend while managing working capital cash requirements.

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").

The Corporation's US$600 million of 5.875% senior unsecured notes due February 2029 represent the only long-term debt maturity. At March 31, 2025, the Corporation had $600 million unutilized capacity under the revolving credit facility and, with $214 million of issued letters of credit, had $386 million of unutilized capacity under the $600 million EDC Facility.

The following table summarizes the Corporation's funds from operations ("FFO") and free cash flow ("FCF"):

Three Months Ended March 31		2025		2024
Net cash provided by (used in) operating activities	**$**	**296**	$	317
Net change in non-cash working capital items		**84**		12
Funds from operations		**380**		329
Capital expenditures		**(157)**		(112)
Free cash flow	**$**	**223**	$	217

Management utilizes FFO and FCF as measures to analyze operating performance and cash flow generating ability. FFO and FCF impact the level and extent of debt repayment, funding for capital expenditures and returning capital to shareholders. FCF is a meaningful metric to assist management and investors in analyzing corporate performance by providing a measure of financial liquidity and the capacity of the business to return capital to shareholders. FFO and FCF are not intended to represent net cash provided by (used in) operating activities.

The following table summarizes the Corporation's net debt:

As at	Note		March 31, 2025		December 31, 2024
Long-term debt	12	**$**	**857**	$	858
Cash and cash equivalents			**(88)**		(156)
Net debt - C$		**$**	**769**	$	702
Net debt - US$		**$**	**535**	$	488

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

Net debt and FCF are not standardized measures and may not be comparable with the calculation of similar measures by other companies.

23. COMMITMENTS AND CONTINGENCIES

a. Commitments

The Corporation’s commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at March 31, 2025:

		2025		2026		2027		2028		2029		Thereafter		Total
Transportation and storage[(i)]	$	380	$	506	$	507	$	512	$	496	$	4,691	$	7,092
Diluent purchases[(ii)]		188		74		65		66		65		32		490
Other operating commitments		15		19		10		9		6		58		117
Variable office lease costs		3		4		4		4		4		8		27
Capital commitments		40		—		—		—		—		—		40
Commitments	**$**	**626**	**$**	**603**	**$**	**586**	**$**	**591**	**$**	**571**	**$**	**4,789**	**$**	**7,766**

(i) *This represents transportation and storage commitments from 2025 to 2048. Excludes amounts recognized on the consolidated balance sheet (Note 11).*

(ii) *The associated transportation commitment is included in transportation and storage.*

b. Contingencies

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