MEG ENERGY

2024 Report to Shareholders, Management's Discussion and Analysis and Annual Financial Statements

For the year ended December 31, 2024

TSX | MEG

Report to Shareholders for the year ended December 31, 2024

(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 fourth quarter and full-year 2024 operational and financial results on February 27, 2025.[1]

“This was a significant year in the history of our company. MEG achieved several key milestones in 2024, including our fourth straight year of record production, hitting our net debt target and establishing a program to return 100% of our free cash flow to shareholders including an inaugural base dividend,” said Darlene Gates, President & Chief Executive Officer of MEG. “MEG is now positioned to grow production and free cash flow per share through share buybacks and our Facility Expansion Project.”

2024 Highlights:

- Generated funds flow from operating activities ("FFO") of $1.4 billion or $5.13 per share, and free cash flow ("FCF") of $837 million or $3.10 per share;
- Record bitumen production of 102,012 bbls/d, within guidance, at a 2.39 steam-oil ratio ("SOR");
- Continued to deliver top-quartile non-energy operating costs of $5.39 per barrel, consistent with our guidance, and energy operating costs net of power revenue of $0.93 per barrel;
- Leveraged Trans Mountain Expansion Project startup and our marketing expertise to access new international customers and improve bitumen realization;
- Achieved our targets for debt reduction and balance sheet strength, reducing net debt to $702 million (US$488 million) as at December 31, 2024, positioning MEG to deliver enhanced capital returns to shareholders going forward;
- Returned $481 million in capital to shareholders through a combination of share buybacks and the initiation of a sustainable quarterly dividend of $0.10 per share:
    - Spent $454 million to repurchase and cancel 17.0 million shares, or 6.2% of shares outstanding at the beginning of the year, and
    - Paid $27 million in dividends;
- Continued improvements in workplace safety performance, driving a reduction in Total Recordable Incident Rate to 0.24 in 2024, from 0.46 in 2022; and
- Made a positive Final Investment Decision ("FID") on the Facility Expansion Project ("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 an anticipated capital cost of $470 million.

[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, adjusted funds flow, free cash flow and net debt.

Fourth Quarter Results

Bitumen production averaged 100,139 barrels per day at a SOR of 2.40 compared to 109,112 barrels per day at a SOR of 2.28 for the same period in 2023. The decrease in production and increase in SOR primarily reflect the timing of new well starts and a one-time, unplanned outage during the fourth quarter of 2024.

FFO and adjusted funds flow ("AFF") were $340 million in the fourth quarter of 2024, compared to $358 million in the same period of 2023, mainly reflecting reduced sales volumes, partially offset by lower diluent expense, royalties and interest expense.

On a diluted per-share basis, AFF increased to $1.29 per share in the fourth quarter of 2024 from $1.27 per share in the comparative 2023 period due to the decrease in the number of shares outstanding as a result of share buybacks.

Fourth quarter net earnings were $106 million in 2024, compared to $103 million in 2023, reflecting lower depletion and depreciation expense in 2024 and an onerous contract expense that was recognized in 2023, largely offset by an unrealized foreign exchange loss on long-term debt and higher deferred income tax expense.

The Corporation returned $178 million in capital to shareholders during the quarter, with $151 million allocated for the repurchase of 5.9 million shares and $27 million used for payment of dividends.

Full-Year Financial Results

MEG generated $1,385 million of FFO and AFF in 2024 compared to $1,476 million and $1,402 million, respectively, in 2023, driven by a lower cash operating netback partially offset by lower interest expense due to debt reduction. The lower 2024 cash operating netback mainly reflects higher royalty expense, partially offset by the benefit of a narrower WTI:AWB differential.

Bitumen realization after net transportation and storage expense increased by 5% to $65.31 per barrel in 2024, primarily driven by narrower WTI:AWB differentials, lower diluent expense and the positive impact of a weaker Canadian dollar, partially offset by a lower average WTI price and lower price realization associated with diverse market access. With respect to WTI:AWB differentials, they averaged about $5.00 per barrel narrower in 2024 versus 2023, reflecting the impact of TMX startup mid-year.

Capital expenditures increased to $548 million in 2024, from $449 million in 2023, reflecting planned investments in the FEP and field development, partially offset by the decreased scope of turnaround activities.

After funding capital expenditures, MEG generated $837 million of 2024 free cash flow, which was used to redeem $351 million (US$258 million) of outstanding 7.125% senior unsecured notes, repurchase and cancel $454 million, or 17.0 million common shares, at a weighted-average price of $26.77 per share, and pay $27 million of base dividends.

Net earnings in 2024 were $507 million, versus $569 million in 2023, reflecting an unrealized foreign exchange loss on long-term debt, increased deferred tax and depletion and depreciation expenses and lower AFF, partially offset by an unrealized gain on risk management and an onerous contract expense recognized in 2023.

Full-Year Production and Operating Results

Average 2024 bitumen production was 102,012 barrels per day at a SOR of 2.39, compared to 101,425 barrels per day in 2023 at a SOR of 2.27. The production increase is due to reduced 2024 turnaround activities, partially offset by cold weather impacts, the timing of new well start-ups and planned facility maintenance. The increase in the SOR primarily reflects planned timing of steam injection in new well starts.

Per barrel non-energy operating costs were $5.39 in 2024 versus $5.01 per barrel in 2023 primarily reflecting an expected increase in labour costs, treating chemical costs, compliance costs and property taxes.

Energy operating costs net of power revenue were $0.93 per barrel in 2024 compared to $0.95 per barrel in 2023. The benefit associated with a weaker AECO natural gas price was largely offset by lower power revenue.

FEP Progress

On November 25, 2024, MEG announced that the Corporation’s Board of Directors had made a positive FID on the 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 an anticipated capital cost of $470 million.

This organic growth project is expected to be entirely self-funded and builds upon the upfront work to delineate the Corporation's reserves. The FEP is expected to deliver significant value for shareholders, with a greater than 50% estimated internal rate of return at US$70 per barrel WTI pricing.

In 2024, the Corporation completed front-end engineering and design and other activities totaling $30 million in capital expenditures. Updates on FEP progress will be provided regularly.

Capital Allocation Strategy

In 2024, the Corporation completed its multi-year debt reduction strategy and initiated a program of increased capital returns to shareholders with 100% of free cash flow allocated to share buybacks and the initiation of a sustainable common share dividend.

MEG's inaugural cash dividend of $0.10 per share was paid on October 15, 2024. On November 5, 2024, the Corporation's Board of Directors declared a $0.10 per share dividend that was paid on January 15, 2025, to shareholders of record at the close of business on December 16, 2024.

On February 27, 2025, the Corporation's Board of Directors declared a quarterly dividend of $0.10 per share for payment on April 15, 2025, to shareholders of record on March 20, 2025.

All dividends paid by MEG are designated as eligible dividends for Canadian federal income tax purposes. Declaration of dividends is at the discretion of the Board of Directors and will continue to be evaluated on a quarterly basis.

The Company intends to renew its normal course issuer bid for a one-year period upon its expiration on March 10, 2025, which will allow the repurchase of up to an additional 10% of MEG's public float.[1]

2025 Guidance

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

Full-year 2025 production guidance includes the impact of a turnaround in the second quarter, with an estimated annualized production impact of 8,000 barrels per day. The full-year production guidance also reflects the startup of two new well pads in the second half of the year, supporting capacity for future production.

The Corporation's $635 million capital expenditure program for 2025 includes $70 million for planned turnaround activities and $130 million for the multi-year FEP. The remaining $435 million expenditure is attributable to normal course sustaining and maintenance activities.

Adjusted Funds Flow Sensitivity

MEG's production is composed entirely of crude oil, and AFF 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.

[1] As defined by the Toronto Stock Exchange

Variable	Range	2025 AFF Sensitivity[(1)(2)] - Cdn$
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).

Pathways Alliance

MEG, along with its Pathways Alliance peers, continues to progress pre-work on the proposed foundational carbon capture and storage project, which will transport CO2 via pipeline from multiple oil sands facilities to be stored permanently underground in the Cold Lake region of Alberta. Pathways Alliance continues to work collaboratively with both the federal and Alberta Governments on the necessary policy and co-financing frameworks required to move the project forward.

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 15 "Non-GAAP and Other Financial Measures" of the Corporation's year ended December 31, 2024 Management's Discussion and Analysis for detailed descriptions of these measures.

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the year ended December 31, 2024 was approved by the Corporation's Board of Directors on February 27, 2025. This MD&A should be read in conjunction with the Corporation's audited annual consolidated financial statements and notes thereto and the Annual Information Form ("AIF") for the year ended December 31, 2024.

Basis of Presentation

This MD&A and the audited annual 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 15 "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, effective royalty rate, 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: adjusted funds flow, free cash flow, and net debt.

MD&A - Table of Contents

1. 2024 HIGHLIGHTS AND 2025 GUIDANCE

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 financial results are based on bitumen sales volumes:

	Three months ended December 31		Year ended December 31	
($millions, except as indicated)	**2024**	**2023**	**2024**	**2023**
Operational results:				
Bitumen production - bbls/d	100,139	109,112	102,012	101,425
Per share, diluted	0.03	0.04	0.14	0.13
Steam-oil ratio	2.40	2.28	2.39	2.27
Bitumen sales - bbls/d	100,821	112,634	101,198	101,086
Benchmark pricing:				
WTI - US$/bbl	70.27	78.32	75.72	77.62
Differential - WTI:WCS - Edmonton - US$/bbl	(12.56)	(21.89)	(14.76)	(18.71)
AWB - Edmonton - US$/bbl	56.82	54.53	59.84	56.83
Financial results:				
Bitumen realization after net transportation and storage expense[(1)] - $/bbl	62.62	63.52	65.31	62.46
Non-energy operating costs[(2)] - $/bbl	5.61	4.64	5.39	5.01
Energy operating costs net of power revenue[(1)] - $/bbl	0.90	1.46	0.93	0.95
Operating expenses net of power revenue[(1)] - $/bbl	6.51	6.10	6.32	5.96
Cash operating netback[(1)] - $/bbl	41.09	38.65	42.25	43.36
General & administrative expense - $/bbl of bitumen production volumes	1.85	1.89	1.95	1.86
Royalties	132	186	591	456
Funds flow from operating activities	340	358	1,385	1,476
Per share, diluted	1.29	1.27	5.13	5.13
Adjusted funds flow[(3)]	340	358	1,385	1,402
Per share, diluted[(3)]	1.29	1.27	5.13	4.87
Capital expenditures	172	104	548	449
Free cash flow[(3)]	168	254	837	953
Per share, diluted[(3)]	0.64	0.90	3.10	3.31
Weighted average common shares outstanding – diluted	263	282	270	288
Debt repayments - US$	—	128	258	322
Share repurchases - C$	151	219	454	446
Dividends paid - C$	27	—	27	—
Revenues	1,147	1,444	5,149	5,653
Net earnings	106	103	507	569
Per share, diluted	0.40	0.37	1.87	1.98
Long-term debt	858	1,124	858	1,124
Net debt - US$[(3)]	488	730	488	730

(1) Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Supplementary financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.
(3) Capital management measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.

Financial Results and Capital Resources

In 2024, the Corporation completed its multi-year debt reduction strategy and increased capital returns to shareholders to 100% of free cash flow through share buybacks and an inaugural base dividend. The Corporation also reached final investment decision and approved the multi-year Christina Lake facility expansion project ("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.

Free cash flow of $837 million, generated in 2024, was used to redeem the remaining US$258 million (approximately $351 million) of outstanding 7.125% senior unsecured notes, return $454 million to shareholders through the repurchase and cancellation of 17.0 million common shares and pay $27 million of base dividends.

Funds flow from operating activities and adjusted funds flow in 2024 were $1,385 million compared to $1,476 million and $1,402 million, respectively, in 2023. The benefits from the narrower WTI:AWB differential in 2024 and lower interest expense due to reduced debt were offset by higher royalty and net transportation and storage expenses. On a diluted per share basis, adjusted funds flow increased to $5.13 per share in 2024, from $4.87 per share in 2023, due to the decrease in the number of shares outstanding as a result of share repurchases.

Average 2024 bitumen production volumes were 102,012 barrels per day at a steam-oil ratio ("SOR") of 2.39, compared to 101,425 barrels per day in 2023 at an SOR of 2.27. The production increase is due to reduced 2024 turnaround activities, partially offset by cold weather impacts, the timing of new well start-ups and planned facility maintenance. The increased SOR primarily reflects planned timing of steam injection in new well starts.

Capital expenditures increased to $548 million in 2024, from $449 million in 2023, reflecting planned investments in the FEP and field development, partially offset by decreased scope and timing of turnaround activities.

Annual net earnings were $507 million during 2024 compared to $569 million in 2023. This decline was primarily driven by an unrealized foreign exchange loss on long-term debt, increased deferred tax expense and a lower adjusted funds flow, partially offset by a 2023 onerous contract expense.

2025 Guidance

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

Annual 2025 production guidance includes the impact of a major second quarter turnaround, with an estimated full-year production impact of 8,000 barrels per day. The annual production guidance also reflects the startup of two new well pads in the second half of the year, supporting capacity for future production.

The Corporation's 2025 $635 million capital expenditure program includes $70 million for planned turnaround activities and $130 million for the multi-year FEP. The remaining $435 million of 2025 capital expenditures consists of sustaining and maintenance activities.

2. BUSINESS OVERVIEW AND STRATEGY

MEG is an energy company focused on *in situ* thermal oil production in the southern Athabasca oil region of Alberta, Canada. MEG is actively developing innovative enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods to improve the economic recovery of oil. MEG transports and sells thermal oil (known as Access Western Blend or "AWB") to customers throughout North America and internationally.

MEG owns a 100% working interest in approximately 410 square miles of mineral leases. In a report dated effective December 31, 2024, GLJ Ltd. ("GLJ"), an independent qualified reserves and resources evaluator, estimated that the Christina Lake Project leases it evaluated contained approximately 1.94 billion barrels of gross proved plus probable ("2P") bitumen reserves as at December 31, 2024. For information regarding MEG's estimated reserves in the report prepared by GLJ, please refer to the Corporation's AIF for the year ended December 31, 2024, which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR+ website at www.sedarplus.ca.

The Christina Lake Project, which contains all the Corporation's 2P reserves has regulatory approval in place for 210,000 barrels per day of production. MEG has developed oil processing capacity of approximately 110,000 barrels per day at its Christina Lake central plant facility, prior to any impact from scheduled and unscheduled maintenance activity or outages. At current production levels, MEG has a 2P reserve life index of approximately 50 years. The average annual production decline rate at the Christina Lake Project has historically been between 10% and 20%, and new well pads are added annually to offset the decline.

Asset Strategy

The Corporation has been able to realize production growth over time at the Christina Lake Project, while minimizing SOR, through the application of reservoir technologies, including MEG's proprietary technology, eMSAGP (which reduces the amount of steam required to produce a barrel of bitumen) as well as enhanced completion designs, and optimized well spacing. MEG also uses combined heat and power generation, known as cogeneration, to create steam and power from a single heat source. The application of eMSAGP and cogeneration have enabled MEG to achieve GHG emissions intensity below the *in situ* industry volume weighted average reported to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator.

The Corporation initiated the multi-year 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. 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.

Safe and reliable operations are critical to MEG. The Corporation continues to invest in its safety leadership program, for both employees and contractors, which is underpinned by a comprehensive Operations Excellence Management System.

Capital Allocation Strategy

After reducing net debt to US$600 million in 2024, MEG started returning 100% of free cash flow to shareholders through share repurchases and quarterly base dividends. Since January 1, 2022, the Corporation has repurchased and cancelled 56.6 million shares, equating to 18.4% of the outstanding shares as at December 31, 2021, and returning $1.3 billion to shareholders. During the fourth quarter of 2024, an inaugural quarterly cash dividend of $27 million, or $0.10 per share was paid.

Marketing Strategy

The Corporation employs a marketing strategy that delivers and sells its production to oil markets throughout North America and internationally. MEG owns, leases and contracts for services on multiple facilities to transport, store and deliver AWB to customers. MEG has 100,000 bbls/d of contracted AWB transportation capacity on the Flanagan South and Seaway pipeline systems ("FSP") providing pipeline transportation directly to USGC refineries and export terminals. In addition, MEG has 20,000 bbls/d of contracted AWB transportation capacity to Canada's west coast on the Trans Mountain Expansion ("TMX") Pipeline. Over 80% of MEG's blend sales have tidewater access, positioning the company with broad market reach and attractive realized prices with reduced differential volatility. MEG has proprietary and contracted oil storage capacity of approximately 2.1 million barrels in Alberta and locations in the U.S., with marine export capacity at Beaumont, Texas in the USGC. This combination of pipeline access, storage capacity and marine export capacity provides MEG with diversified, long-term, and reliable market access to world oil prices.

MEG also has a long-term Access Pipeline commitment to deliver AWB from its Christina Lake Project to Edmonton refineries and export pipelines. In addition to the Access Pipeline, a separate diluent pipeline system runs from the Edmonton area to MEG’s Christina Lake Project. It allows MEG to effectively manage diluent supply for blending with its Christina Lake production. The diluent system receives volumes from numerous local production streams and fractionation facilities as well as imported diluent from inbound pipelines. This connection to key pipeline and storage systems in the Edmonton/Fort Saskatchewan corridor and import volumes from the U.S. provides a range of diluent supply alternatives to mitigate supply and price risk.

MEG's approximately 1.1 million barrels of storage and terminalling capacity in the Edmonton area, includes approximately 0.9 million barrels of contracted Stonefell Terminal capacity. The Stonefell Terminal is connected to the Access Pipeline System. The Corporation also has approximately 1.0 million barrels of contracted storage capacity in the USGC area, along with marine export capacity at Beaumont, Texas.

These marketing transportation, storage, and delivery facilities provide MEG with the ability to: (i) sell and deliver AWB to a variety of markets; (ii) access multiple sources of diluent; and (iii) store both bitumen blend and diluent in periods of market and transportation disruptions or constraints.

Pathways

MEG, along with its Pathways Alliance peers, continues to progress pre-work on this foundational carbon capture and storage project, which will transport CO_2 via pipeline from multiple oil sands facilities to be stored permanently underground in the Cold Lake region of Alberta. Pathways Alliance continues to work collaboratively with both the federal and Alberta Governments on the necessary policy and co-financing frameworks required to move the project forward.

3. FOURTH QUARTER HIGHLIGHTS

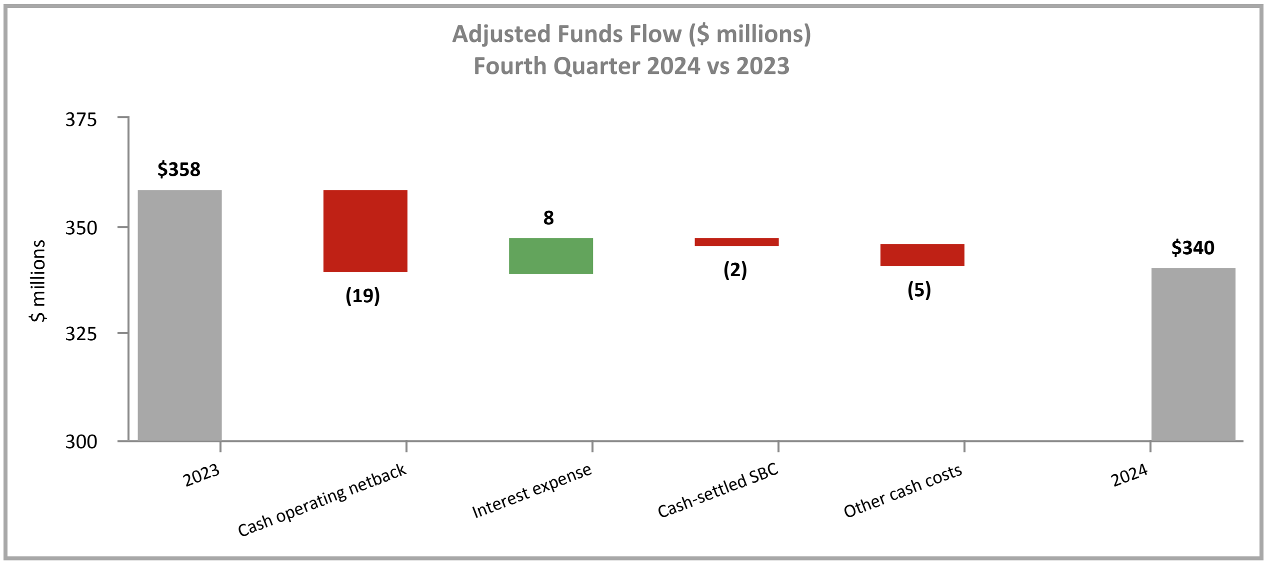
The Corporation generated funds flow from operating activities and adjusted funds flow of $340 million, or $1.29 per share, during the fourth quarter of 2024. After $172 million of capital expenditures, the Corporation's remaining $168 million of free cash flow, plus cash on hand, was used to return $151 million to shareholders through the repurchase and cancellation of 5.9 million shares at a weighted-average price of $25.60 per share and pay a quarterly base dividend of $27 million.

Average bitumen production volumes in the fourth quarter of 2024 were 100,139 barrels per day at a SOR of 2.40 compared to 109,112 barrels per day at a SOR of 2.28 in the comparative 2023 period. The decrease in production and increase in SOR primarily reflect timing of new well starts and a one-time unplanned outage during the fourth quarter of 2024.

	Three months ended December 31	
	2024	**2023**
Bitumen production – bbls/d	**100,139**	109,112
Steam-oil ratio (SOR)	**2.40**	2.28

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

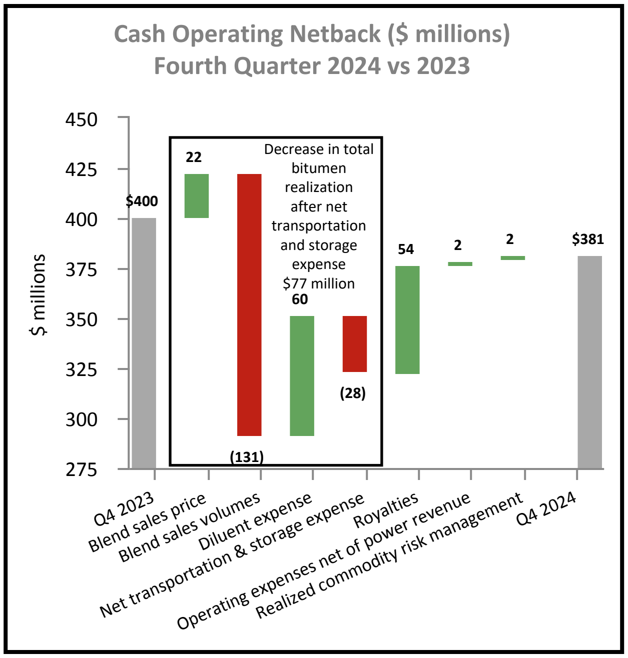
	Three months ended December 31	
($millions)	**2024**	**2023**
Funds flow from operating activities and Adjusted funds flow	**$ 340**	$ 358
Capital expenditures	**(172)**	(104)
Free cash flow	**$ 168**	$ 254
Adjusted funds flow per share - diluted	**$ 1.29**	$ 1.27

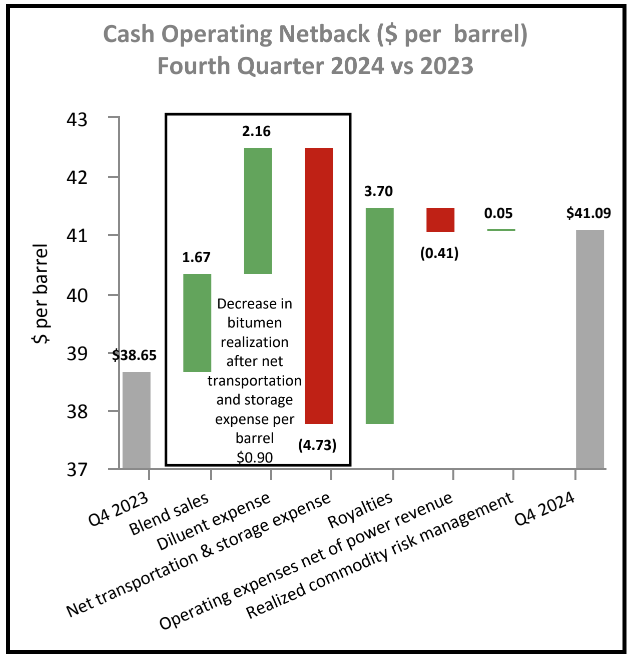


Funds flow from operating activities and adjusted funds flow decreased during the fourth quarter of 2024, compared to the same period of 2023, driven mainly by a lower cash operating netback partially offset by lower interest expense due to reduced debt levels. On a diluted per share basis, adjusted funds flow increased to $1.29 in the fourth quarter of 2024 from $1.27 in the comparative 2023 period due to the decrease in the number of shares outstanding as a result of share buybacks.

	Three months ended December 31			
	2024		**2023**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Sales from production	**$ 1,165**		$ 1,262	
Sales from purchased product[1]	**102**		349	
Petroleum revenue	**1,267**		1,611	
Purchased product[1]	**(99)**		(334)	
Blend sales[2][3]	**$ 1,168**	**$ 89.00**	$ 1,277	$ 87.33
Diluent expense	**(411)**	**(7.42)**	(471)	(9.58)
Bitumen realization[3]	**757**	**81.58**	806	77.75
Net transportation and storage expense[3][4]	**(176)**	**(18.96)**	(148)	(14.23)
Bitumen realization after net transportation and storage expense	**581**	**62.62**	658	63.52
Royalties	**(132)**	**(14.22)**	(186)	(17.92)
Operating expenses net of power revenue[3]	**(61)**	**(6.51)**	(63)	(6.10)
Realized gain (loss) on commodity risk management	**(7)**	**(0.80)**	(9)	(0.85)
Cash operating netback[3]	**$ 381**	**$ 41.09**	$ 400	$ 38.65
Bitumen sales volumes - bbls/d		**100,821**		112,634

(1) Sales and purchases of oil products related to marketing asset optimization activities.
(2) Blend sales per barrel are based on blend sales volumes.
(3) Non-GAAP financial measure - please refer to section 15 "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.

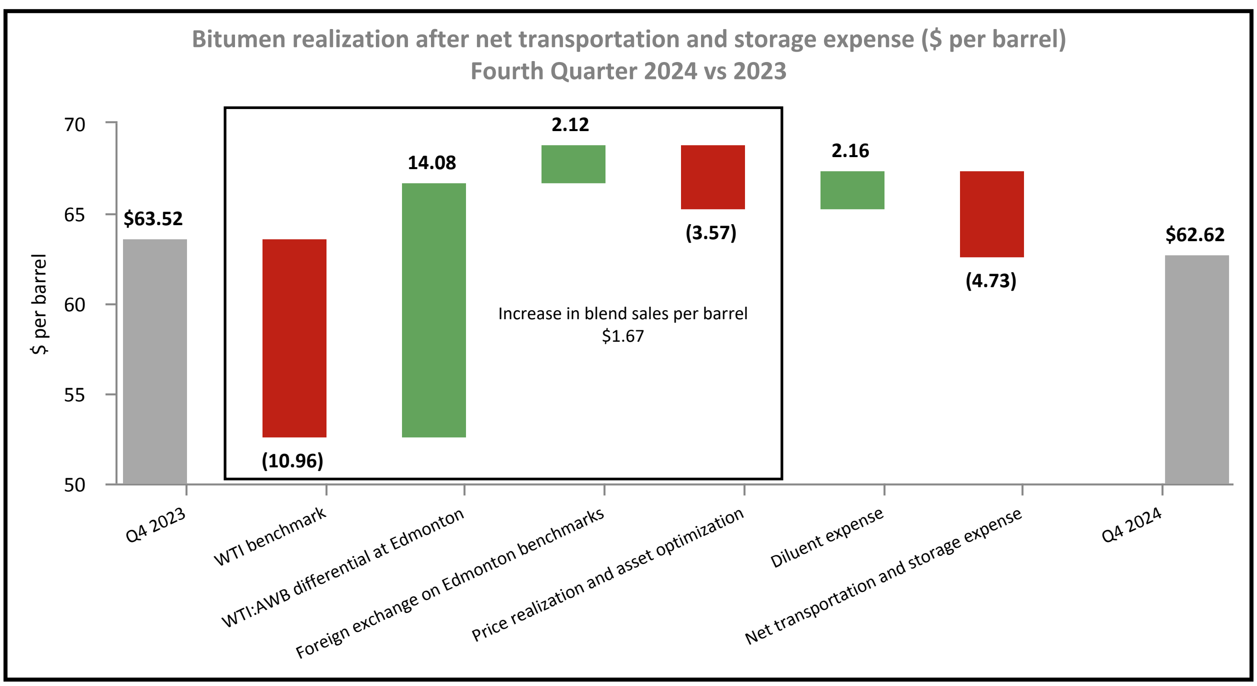




During the fourth quarter of 2024, total cash operating netback decreased 5% to $381 million compared to $400 million during the same period of 2023, mainly reflecting reduced sales volumes, partially offset by lower diluent expense and royalties.

During the fourth quarter of 2024, cash operating netback per barrel increased by 6% to $41.09 per barrel, from $38.65 per barrel in the comparative 2023 period, primarily reflecting reduced royalties partially offset by a lower bitumen realization after net transportation and storage expense.

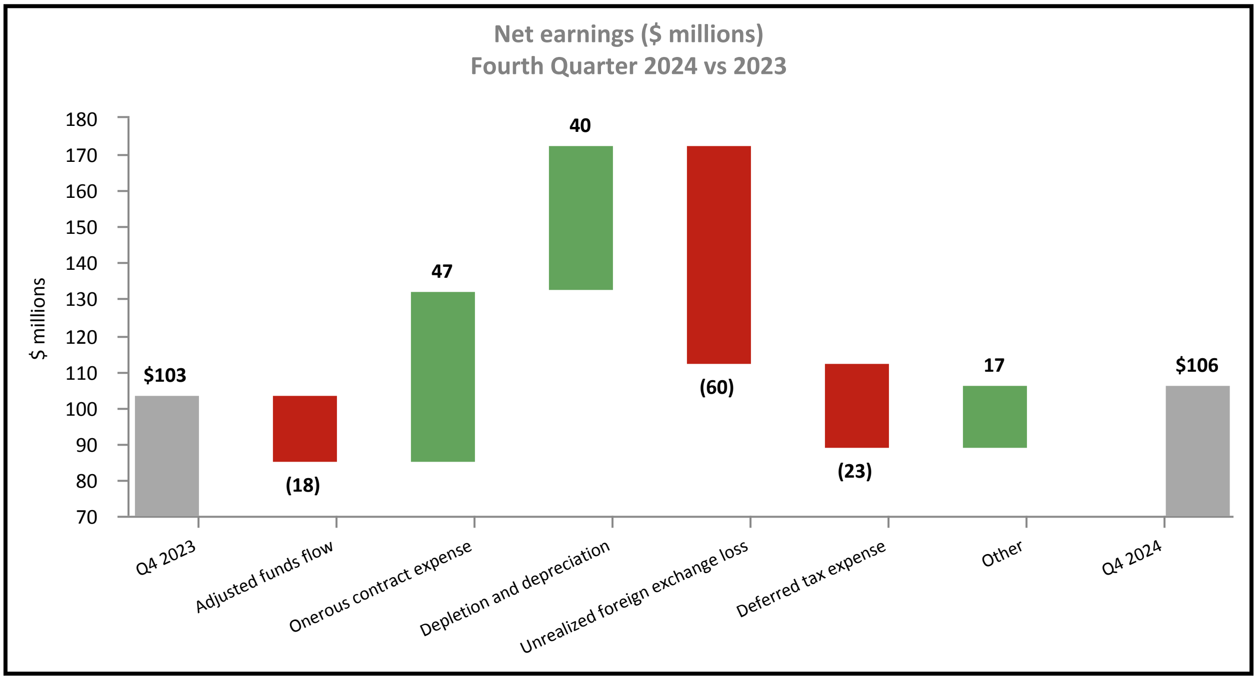
Lower fourth quarter 2024 royalties were driven by lower net revenues compared to the same period of 2023.



Bitumen realization after net transportation and storage expense was $62.62 per barrel in the fourth quarter of 2024 compared to $63.52 per barrel in the same period of 2023. The benefits from narrower WTI:AWB differentials, lower diluent expense and the positive impact of a weaker Canadian dollar were offset by a lower average WTI price, a lower price realization associated with diverse market access and higher net transportation and storage expense.

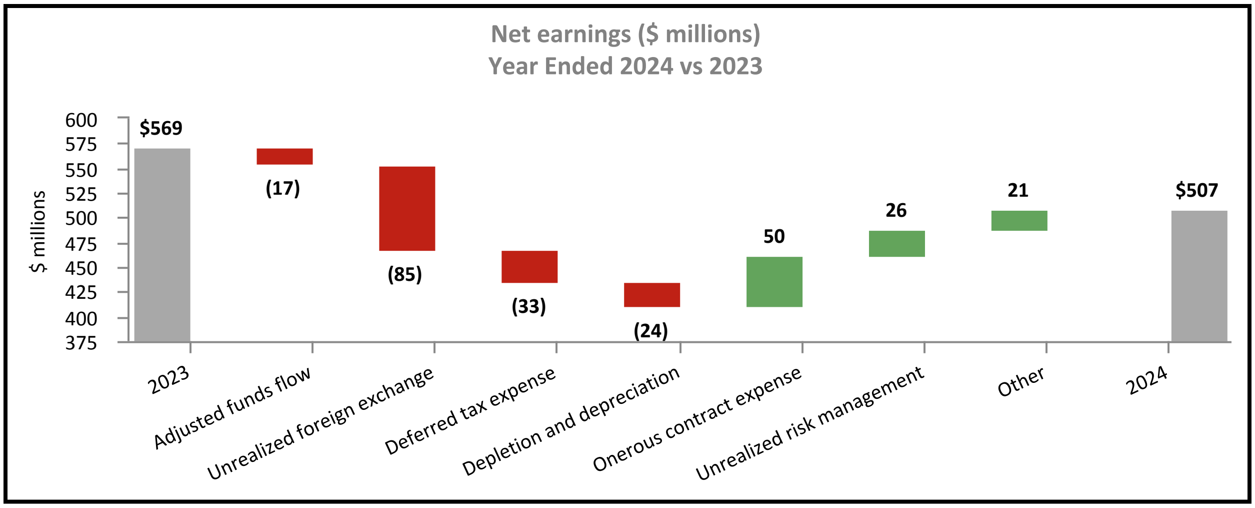
Decreased diluent expense, on a total and per barrel basis, reflects narrower WTI:AWB differentials partially offset by a higher average condensate price, relative to WTI. The decrease in total diluent expense also reflects lower diluent volumes required for blending. The Corporation recovered 83% of diluent costs through blend sales during the fourth quarter of 2024 compared to 79% in the same period of 2023.

Increased net transportation and storage expense, on a total and per barrel basis, during the fourth quarter of 2024 reflects new tolls on volumes transported to the west coast of Canada on the TMX Pipeline. With the start-up of the TMX Pipeline, the Corporation began shipping AWB to Canada's West Coast during the second quarter of 2024 under its 20,000 bbls/d contracted transportation capacity arrangement.



Fourth quarter net earnings were $106 million in 2024, compared to $103 million during the same period of 2023, reflecting lower depletion and depreciation and an onerous contract expense that was recognized in 2023, largely offset by an unrealized foreign exchange loss on long-term debt and higher deferred income tax expense.

4. ANNUAL NET EARNINGS



Annual 2024 net earnings declined to $507 million from $569 million in 2023. The decline in 2024 was primarily driven by an unrealized foreign exchange loss on long-term debt, increased deferred tax and depletion and depreciation expenses and a lower adjusted funds flow, partially offset by an unrealized gain on risk management and an onerous contract expense recognized in 2023.

5. REVENUES

($millions)		**2024**		**2023**
Sales from:				
Production	**$**	**4,704**	$	4,548
Purchased product[(1)]		**978**		1,444
Petroleum revenue	**$**	**5,682**	$	5,992
Royalties		**(591)**		(456)
Petroleum revenue, net of royalties	**$**	**5,091**	$	5,536
Power revenue	**$**	**56**	$	114
Transportation revenue		**2**		3
Power and transportation revenue	**$**	**58**	$	117
Revenues	**$**	**5,149**	$	5,653

(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 2024, petroleum revenue, net of royalties decreased to $5.1 billion from $5.5 billion in 2023 reflecting reduced sales from purchased product and higher royalties partially offset by increased sales from production.

Revenues include the sale of third-party products related to marketing asset optimization activities. The associated purchase of third-party products is recognized within "Purchased product" expense. These transactions are mainly undertaken to recover fixed costs related to transportation and storage contracts. The Corporation does not engage in speculative trading. The purchase and sale of third-party products to facilitate marketing asset optimization activities requires the elimination of price risk pursuant to policies approved by the Corporation's Board of Directors, which can be achieved either through physical transactions or through financial price risk management.

6. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	2024	2023
Bitumen production – bbls/d	**102,012**	101,425
Steam-oil ratio (SOR)	**2.39**	2.27

Bitumen Production

Bitumen production increased 1% to 102,012 barrels per day in 2024 from 101,425 barrels per day in 2023. The increased production volume primarily reflects the impact of a major planned turnaround at the Christina Lake Facility during the second quarter of 2023, whereas turnaround activities in 2024 were reduced and spread more evenly throughout the year. Production during 2024 was also impacted by cold weather in the first half of the year, the timing of new well start-ups and planned facility maintenance.

Steam-Oil Ratio ("SOR")

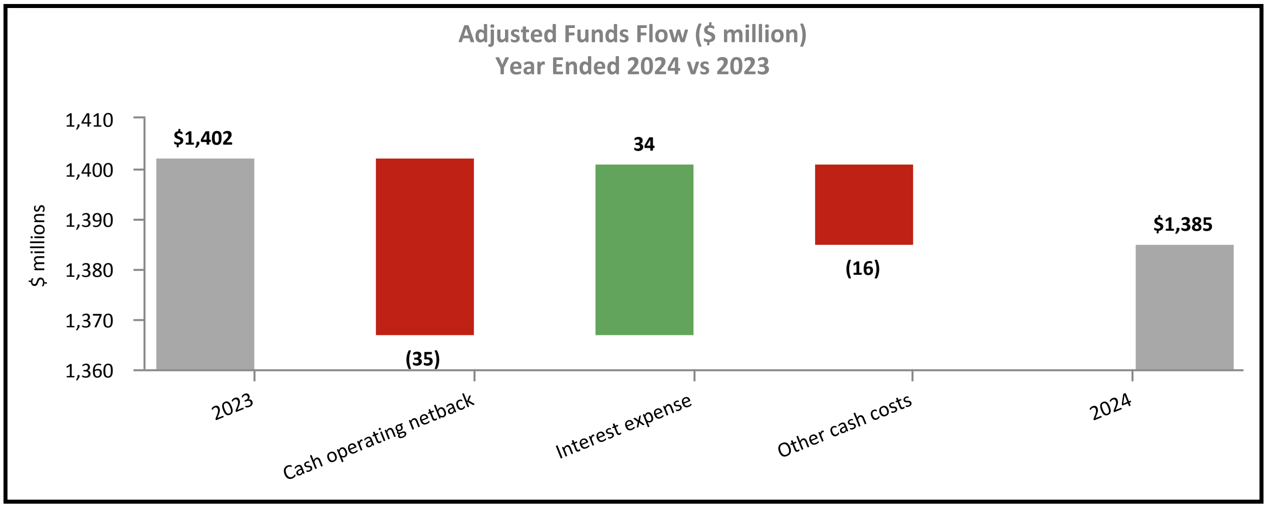
The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is SOR, which is an efficiency indicator that measures the amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR increased from 2023 to 2024 by approximately 5% to 2.39 primarily due to planned timing of injecting steam in new well starts.

Funds Flow from Operating Activities and Adjusted Funds Flow

Funds flow from operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as funds flow from operating activities excluding items not considered part of ordinary continuing operations. Adjusted funds flow is used by management to analyze the Corporation's operating performance and cash flow generating ability. By excluding non-recurring adjustments from cash flows, the adjusted funds flow measure establishes a clearer link between cash flows and the cash operating netback.

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

($millions, except as indicated)	2024	2023
Funds flow from operating activities	**$ 1,385**	$ 1,476
Adjustments:		
Impact of cash-settled SBC units subject to equity price risk management	**—**	13
Realized equity price risk management gain	**—**	(87)
Adjusted funds flow	**$ 1,385**	$ 1,402
Adjusted funds flow per share - diluted	**$ 5.13**	$ 4.87



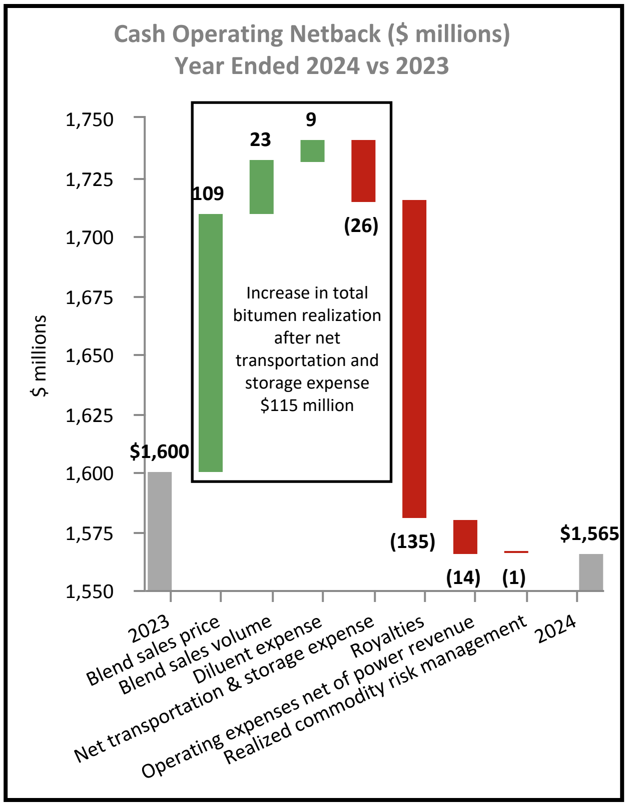
Funds flow from operating activities and adjusted funds flow decreased in 2024, compared to 2023, driven mainly by a lower cash operating netback partially offset by lower interest expense due to reduced debt levels. On a diluted per share basis, adjusted funds flow increased to $5.13 per share in 2024 from $4.87 per share in 2023 due to the decrease in the number of shares outstanding as a result of share buybacks.

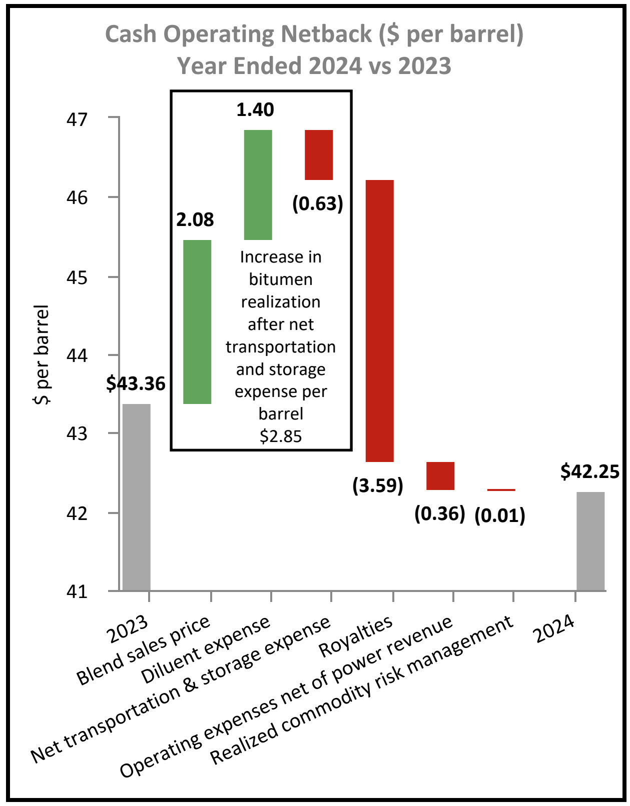
CASH OPERATING NETBACK

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

	2024		2023	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Sales from production	**$ 4,704**		$ 4,548	
Sales from purchased product[1]	**978**		1,444	
Petroleum revenue	**$ 5,682**		$ 5,992	
Purchased product[1]	**(958)**		(1,400)	
Blend sales[2][3]	**$ 4,724**	**$ 90.02**	$ 4,592	$ 87.94
Diluent expense	**(1,682)**	**(7.90)**	(1,691)	(9.30)
Bitumen realization[3]	**$ 3,042**	**$ 82.12**	$ 2,901	$ 78.64
Net transportation and storage expense[3][4]	**(623)**	**(16.81)**	(597)	(16.18)
Bitumen realization after net transportation and storage expense[3]	**$ 2,419**	**$ 65.31**	$ 2,304	$ 62.46
Royalties	**(591)**	**(15.96)**	(456)	(12.37)
Operating expenses net of power revenue[3]	**(234)**	**(6.32)**	(220)	(5.96)
Realized gain (loss) on commodity risk management	**(29)**	**(0.78)**	(28)	(0.77)
Cash operating netback[3]	**$ 1,565**	**$ 42.25**	$ 1,600	$ 43.36
Bitumen sales volumes - bbls/d		**101,198**		101,086

(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 15 "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 2024, cash operating netback, on a total and per barrel basis, decreased compared to 2023 mainly reflecting higher royalties partially offset by higher bitumen realization after net transportation and storage expense.

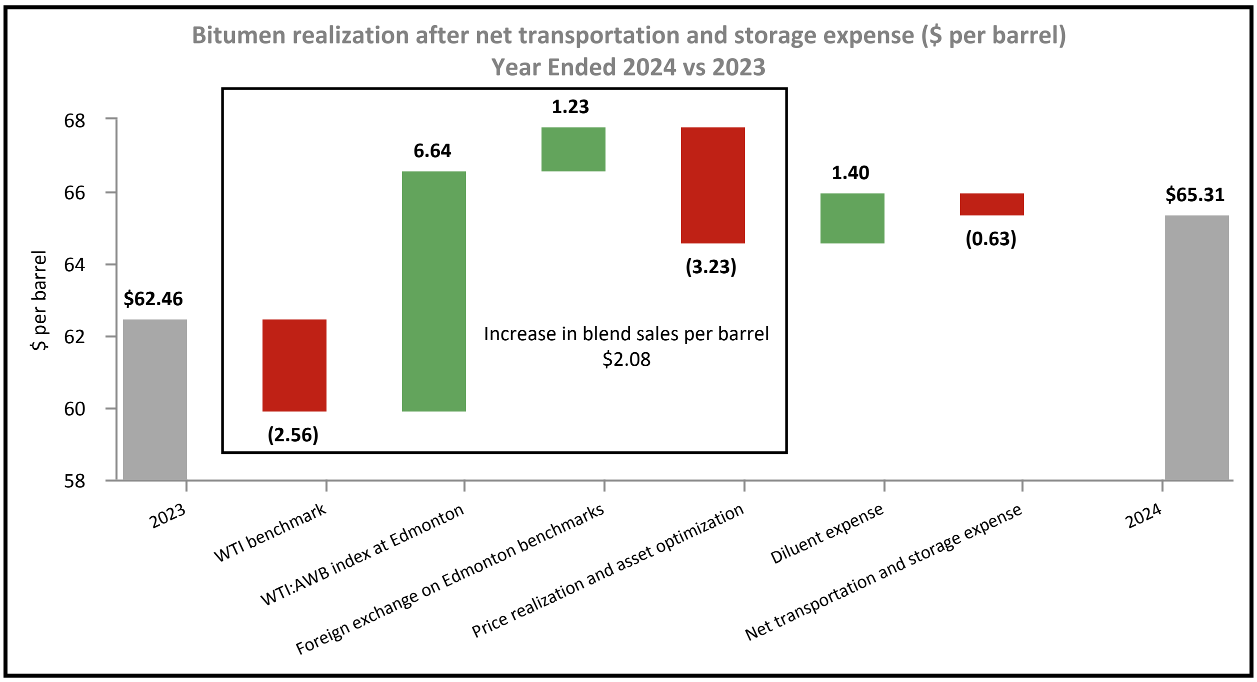
Bitumen Realization after Net Transportation and Storage Expense

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 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.

	2024		2023	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Sales from production	**$ 4,704**		$ 4,548	
Sales from purchased product[1]	**978**		1,444	
Petroleum revenue	**$ 5,682**		$ 5,992	
Purchased product[1]	**(958)**		(1,400)	
Blend sales[2][3]	**$ 4,724**	**$ 90.02**	$ 4,592	$ 87.94
Diluent expense	**(1,682)**	**(7.90)**	(1,691)	(9.30)
Bitumen realization[3]	**$ 3,042**	**$ 82.12**	$ 2,901	$ 78.64
Net transportation and storage expense[3]	**(623)**	**(16.81)**	(597)	(16.18)
Bitumen realization after net transportation and storage expense	**$ 2,419**	**$ 65.31**	$ 2,304	$ 62.46
Bitumen sales volumes - bbls/d		**101,198**		101,086

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



Bitumen realization after net transportation and storage expense increased 5%, to $65.31 per barrel, in 2024, from $62.46 per barrel in 2023, primarily driven by narrower WTI:AWB differentials, lower diluent expense and the positive impact of a weaker Canadian dollar, partially offset by a lower average WTI price and price realization associated with diverse market access.

Diluent expense per barrel, which reflects the purchased cost of diluent not recovered through blend sales, is impacted by condensate prices relative to WTI and the WTI:AWB differential. Diluent expense per barrel in 2024 decreased to $7.90 from $9.30 in 2023. The Corporation recovered 83% of diluent costs through blend sales in 2024 compared to 80% in 2023 as WTI:AWB differentials narrowed.

Total diluent expense reflects absolute condensate prices and purchased volumes. Total diluent expense decreased to $1,682 million in 2024, from $1,691 million in 2023, reflecting a lower average condensate price in 2024.

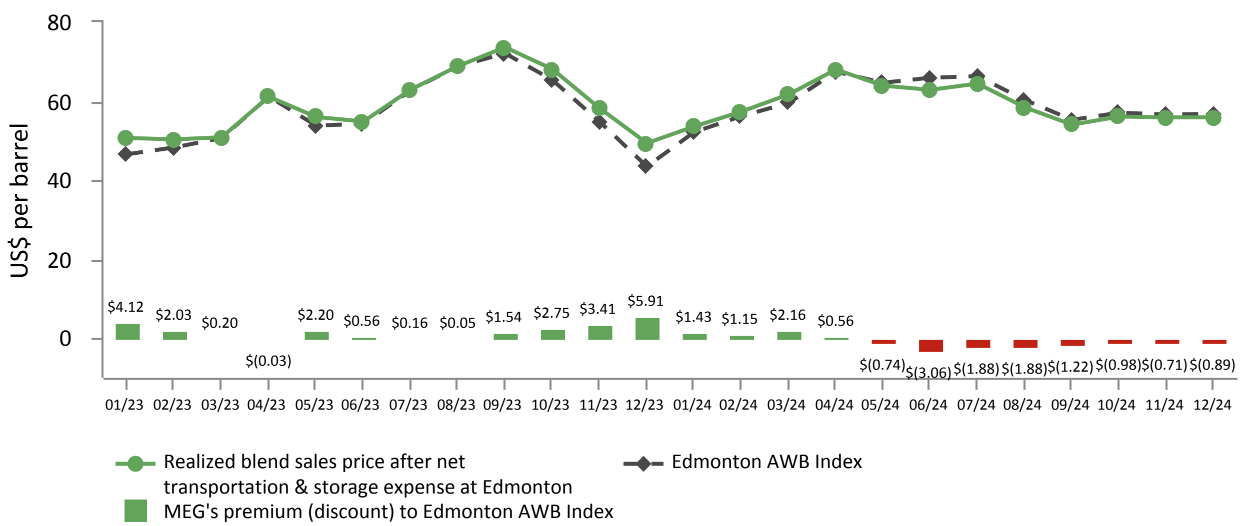
	2024		2023	
($millions, except as indicated)		$/bbl		$/bbl
Transportation and storage expense	**$ (625)**	**$ (16.86)**	$ (600)	$ (16.27)
Transportation revenue	**2**	**0.05**	3	0.09
Net transportation and storage expense	**$ (623)**	**$ (16.81)**	$ (597)	$ (16.18)
Bitumen sales volumes - bbls/d		**101,198**		101,086

Net transportation and storage expense in 2024, on a total and per barrel basis, rose relative to 2023 primarily reflecting new tolls on volumes transported to the west coast of Canada on TMX partially offset by lower volumes shipped to the USGC.

The Corporation partially reduced the cost of transportation and storage assets through the purchase and sale of non-proprietary product. These asset optimization activities contributed $20 million, or $0.39 per barrel, to blend sales in 2024 compared to $44 million, or $0.84 per barrel, in 2023.

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.

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



In 2024, the Corporation's overall average realized blend sales price after net transportation and storage expense received a discount of US$0.49 per barrel compared to the Edmonton AWB index.

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

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

($millions)		**2024**		2023
Bitumen realization(1)	**$**	**3,042**	$	2,901
Transportation and storage expense		**(625)**		(600)
Transportation revenue		**2**		3
Bitumen realization after net transportation and storage expense	**$**	**2,419**	$	2,304
Royalties	**$**	**591**	$	456
Effective royalty rate(1)(2)		**24.4 %**		19.8 %

(1) Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Effective royalty rate is calculated as royalties divided by bitumen realization after net transportation and storage expense.

The Corporation's Christina Lake operation reached payout status during the second quarter of 2023 resulting in a higher effective royalty rate in 2024 compared to 2023.

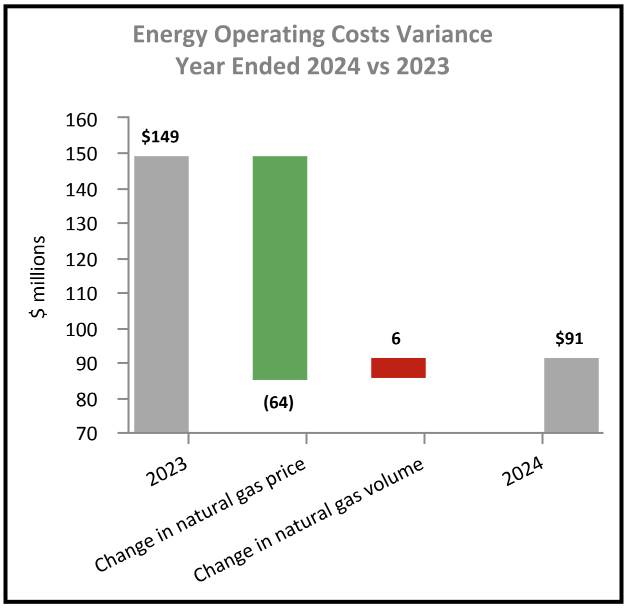
Operating Expenses net of Power Revenue

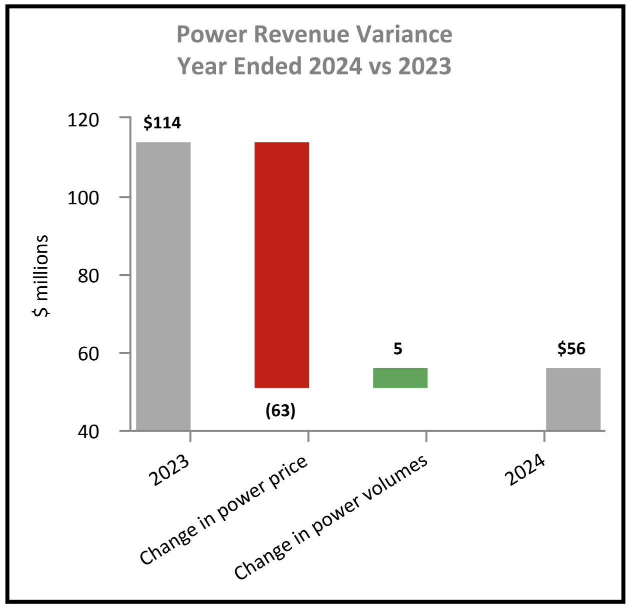
Operating expenses net of power revenue are comprised of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-oriented operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate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

		2024				2023		
($millions, except as indicated)				**$/bbl**				**$/bbl**
Non-energy operating costs(1)	**$**	**(199)**	**$**	**(5.39)**	$	(185)	$	(5.01)
Energy operating costs(1)		**(91)**		**(2.45)**		(149)		(4.03)
Operating expenses		**(290)**		**(7.84)**		(334)		(9.04)
Power revenue		**56**		**1.52**		114		3.08
Operating expenses net of power revenue(2)	**$**	**(234)**	**$**	**(6.32)**	$	(220)	$	(5.96)
Energy operating costs net of power revenue(2)	**$**	**(35)**	**$**	**(0.93)**	$	(35)	$	(0.95)
Average delivered natural gas price (C$/mcf)			**$**	**1.94**			$	3.38
Average realized power sales price (C$/Mwh)			**$**	**64.64**			$	136.50

(1) Supplementary financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.

Non-energy operating costs in 2024, on a total and per barrel basis, increased compared to 2023 primarily reflecting expected increases in labour costs, treating chemical costs, compliance costs and property taxes.





Lower energy operating costs in 2024, on a total and per barrel basis, primarily reflect a weaker AECO natural gas price partially offset by higher natural gas volumes, relative to 2023.

Power revenue decreased from 2023 to 2024 reflecting a 53% decline in the realized power price partially offset by higher power sales volumes.

Overall, energy operating costs net of power revenue per barrel were $0.93 during 2024 compared to $0.95 in 2023. The benefit associated with a weaker AECO natural gas price was partially offset by lower power revenue.

Capital Expenditures

($millions)	**2024**	**2023**
Sustaining and maintenance	**$ 439**	$ 383
Capacity growth[(1)]	**95**	—
Turnaround	**14**	66
	$ 548	$ 449

(1) *Includes approximately $65 million for field infrastructure and pad development and $30 million for the FEP.*

Higher capital expenditures during 2024, relative to 2023, primarily reflect higher planned field development activity together with investment in capacity growth. This increase was partially offset by a decrease in the scope and timing of planned turnaround activities. The Corporation performed a major turnaround at the Christina Lake Facility in the second quarter of 2023 while turnaround activities in 2024 were reduced and spread more evenly throughout the year.

During the fourth quarter of 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. During 2024, $30 million was incurred on the project and the remaining $440 million is forecast to be incurred over the next three years.

7. OUTLOOK

The Corporation's 2024 annual results were in line with the November 27, 2023 guidance ranges.

Summary of 2024 Guidance	Annual Results	Original Guidance (November 27, 2023)
Bitumen production - annual average	102,012 bbls/d	102,000 to 108,000 bbls/d
Capital expenditures	$548 million	$550 million
Non-energy operating costs	$5.39 per bbl	$5.10 to $5.40 per bbl
General and administrative expense	$1.95 per bbl	$1.75 to $1.95 per bbl

On November 25, 2024 the Corporation released its 2025 operating and capital guidance.

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 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.

8. 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	Year ended December 31		2024				2023			
	2024	2023	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Crude oil prices										
Brent (US$/bbl)	**79.82**	81.95	**73.98**	78.47	84.99	81.85	81.61	85.95	78.01	82.21
WTI (US$/bbl)	**75.72**	77.62	**70.27**	75.09	80.57	76.96	78.32	82.26	73.78	76.13
Differential – WTI:WCS – Edmonton (US$/bbl)	**(14.76)**	(18.71)	**(12.56)**	(13.55)	(13.61)	(19.31)	(21.89)	(12.91)	(15.16)	(24.88)
AWB – Edmonton (US$/bbl)	**59.84**	56.83	**56.82**	60.62	65.99	55.96	54.53	67.88	56.41	48.50
Condensate prices										
Condensate at Edmonton (C$/bbl)	**99.92**	103.40	**98.86**	97.10	105.56	98.18	103.90	104.62	97.19	107.91
Condensate at Edmonton as a % of WTI	**96.3**	98.7	**100.6**	94.8	95.7	94.6	97.4	94.8	98.1	104.8
Condensate at Mont Belvieu, Texas (US$/bbl)	**63.60**	63.96	**62.86**	62.06	64.96	64.52	62.28	64.90	60.54	68.13
Condensate at Mont Belvieu, Texas as a % of WTI	**84.0**	82.4	**89.5**	82.6	80.6	83.8	79.5	78.9	82.1	89.5
Natural gas prices										
AECO (C$/mcf)	**1.59**	2.88	**1.61**	0.75	1.29	2.72	2.51	2.83	2.67	3.51
Electric power prices										
Alberta power pool (C$/MWh)	**62.78**	133.61	**51.73**	55.23	45.28	98.87	81.76	151.18	159.87	141.63
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.3700**	1.3495	**1.3991**	1.3636	1.3684	1.3488	1.3618	1.3410	1.3430	1.3520
C$ equivalent of 1 US$ – period end	**1.4405**	1.3205	**1.4405**	1.3505	1.3687	1.3533	1.3205	1.3537	1.3238	1.3528

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 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 2% in 2024, relative to 2023, primarily driven by lower than expected global oil demand growth and excess supply capacity.

WCS and AWB differentials improved in 2024, relative to 2023, reflecting sustained global demand for heavy crude and the unconstrained egress enabled by the TMX pipeline start-up. During 2024, the AWB Edmonton index rose US$3.01 per barrel, to US$59.84 per barrel, relative to 2023 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, as a percentage of WTI, fell to 96.3% in 2024 compared to 98.7% in 2023 primarily due to lower international manufacturing output and the associated curtailment in petrochemical feedstock demand. In addition, the narrower 2024 heavy oil differential improved the recovery of diluent costs in blend sales, reducing per barrel diluent expense.

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 45% in 2024, relative to 2023, primarily due to continued strong natural gas production in Alberta more than offsetting demand growth.

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 53% in 2024, compared to 2023, reflecting increasing penetration of renewables, start-up of several new large-scale gas fired generation units and substantially lower natural gas prices.

9. OTHER OPERATING RESULTS

General and Administrative

($millions, except as indicated)	**2024**	2023
General and administrative	**$ 73**	$ 69
General and administrative expense per barrel of production	**$ 1.95**	$ 1.86
Bitumen production - bbls/d	**102,012**	101,425

Depletion and Depreciation

($millions, except as indicated)	**2024**	2023
Depletion and depreciation expense	**$ 620**	$ 596
Depletion and depreciation expense per barrel of production	**$ 16.61**	$ 16.10
Bitumen production - bbls/d	**102,012**	101,425

During 2024, depletion and depreciation expense rose by $24 million, compared to 2023, mainly reflecting the impact of higher estimated future development costs on the per barrel depletion and depreciation rate as well as increased bitumen production.

Stock-based Compensation

($millions)	2024	2023
Cash-settled expense	**$ 5**	$ 19
Equity-settled expense	**19**	25
Equity price risk management gain	**—**	(9)
Stock-based compensation expense	**$ 24**	$ 35

The decrease in stock-based compensation expense in 2024, compared to 2023, mainly reflects the reduction in the Corporation's share price and fewer cash-settled and equity-settled units outstanding.

The equity price risk management gain recognized in the first quarter of 2023 reflected the increase in the Corporation's share price during that quarter. All equity price risk management contracts were fully realized as at March 31, 2023.

Foreign Exchange Gain (Loss)

($millions)	2024	2023
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ (82)**	$ 26
US$ denominated cash and cash equivalents	**17**	(6)
Unrealized net gain (loss) on foreign exchange	**(65)**	20
Realized gain (loss) on foreign exchange	**(2)**	2
Foreign exchange gain (loss)	**$ (67)**	$ 22

C$ equivalent of 1 US$		
Beginning of period	**1.3205**	1.3534
End of period	**1.4405**	1.3205

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.

During 2024, the Canadian dollar weakened 9% relative to the U.S. dollar resulting in an unrealized foreign exchange loss of $65 million.

In 2023, the Canadian dollar strengthened 2% against the U.S. dollar generating a $20 million unrealized foreign exchange gain.

Net Finance Expense

($millions)		2024		2023
Interest expense on long-term debt	**$**	**59**	$	90
Interest expense on lease liabilities		**25**		24
Credit facility fees		**16**		18
Interest income		**(8)**		(6)
Net interest expense		**92**		126
Debt extinguishment expense		**7**		12
Accretion on provisions		**14**		11
Net finance expense	**$**	**113**	$	149
Average effective interest rate		**6.1%**		6.4%

Interest expense on long-term debt decreased during 2024, compared to 2023, primarily reflecting debt repayments.

Debt extinguishment expense of $7 million was recognized on 2024 debt redemptions. Refer to Note 12 of the consolidated financial statements for further details.

Income Tax

($millions)		2024		2023
Earnings before income taxes	**$**	**696**	$	723
Effective tax rate		**27 %**		21 %
Income tax expense	**$**	**189**	$	154

At December 31, 2024, the Corporation had approximately $3.7 billion of available Canadian tax pools, including $2.3 billion of non-capital losses and $0.2 billion of capital losses, and recognized a deferred income tax liability of $362 million.

The effective tax rate for 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 and the impact of an adjustment to the tax treatment of debt redemption costs.

10. SUMMARY OF ANNUAL INFORMATION

($millions, except per share amounts)	**2024**	2023	2022
Revenue	**$ 5,149**	$ 5,653	$ 6,118
Net earnings	**507**	569	902
Per share - diluted	**1.87**	1.98	2.92
Total assets	**6,744**	6,898	7,033
Total non-current liabilities	**1,637**	1,787	1,996

Revenue

Revenue in 2024 declined 9% from 2023 reflecting reduced sales from purchased product and higher royalties partially offset by an increased blend sales price. The increase in the blend sales price was driven by narrower WTI:AWB differentials and the positive impact of a weaker Canadian dollar partially offset by a lower WTI price and price realization associated with diverse market access.

Revenue in 2023 declined 8% from 2022. A weaker average WTI price and increased royalties more than offset higher blend sales volumes, increased purchased product sales and the positive impact of a weaker Canadian dollar. Increased purchased product sales resulted from asset optimization activities to mitigate the cost of transportation and storage assets.

Net Earnings

Annual net earnings declined to $507 million during 2024 from $569 million in 2023. This decline was primarily driven by an unrealized foreign exchange loss on long-term debt, increased deferred tax and depletion and depreciation expenses and a lower adjusted funds flow, partially offset by an unrealized gain on risk management and a 2023 onerous contract expense.

Annual 2023 net earnings declined to $569 million from $902 million in 2022. This decline was primarily driven by lower adjusted funds flow, higher depletion and depreciation expense and an onerous contract expense partially offset by reduced deferred tax expense and an unrealized foreign exchange gain on long-term debt.

Total Assets

Total assets at December 31, 2024 decreased $154 million, to $6.7 billion, from $6.9 billion at December 31, 2023. Property, plant and equipment decreased as depletion and depreciation charges exceeded capital expenditures and cash and cash equivalents were used for debt repayment, share repurchases and dividend payments.

Total assets at December 31, 2023 decreased $135 million, to $6.9 billion, from $7.0 billion at December 31, 2022. Cash and cash equivalents in 2023 were used for debt repayment and share repurchases, the mark-to-market value of risk management assets decreased with fewer December 31, 2023 contracts outstanding and property, plant and equipment declined as depletion and depreciation charges exceeded capital expenditures.

Total Non-Current Liabilities

Total non-current liabilities declined in 2024 compared to 2023 primarily reflecting the redemption of the remaining US$258 million (approximately $351 million) of outstanding 7.125% senior unsecured notes and a reduction in the decommissioning provision, partially offset by an increase in the deferred income tax liability.

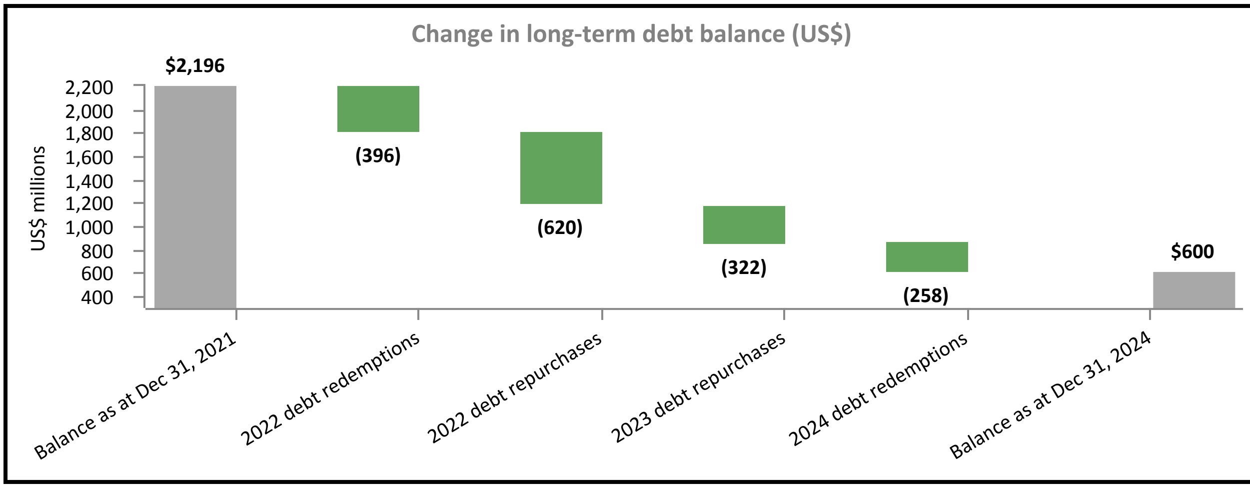
Lower December 31 total non-current liabilities in 2023 compared to 2022 primarily reflect US$322 million (approximately $437 million) of long-term debt repurchased during 2023. This was partially offset by increases in the decommissioning provision and deferred income tax liability as well as a 2023 onerous contract provision.

11. LIQUIDITY AND CAPITAL RESOURCES

($millions)	December 31, 2024	December 31, 2023
Unsecured:		
7.125% senior unsecured notes (December 31, 2024 - US$nil; due 2027; December 31, 2023 - US$258.2 million)	**$ —**	$ 341
5.875% senior unsecured notes (December 31, 2024 - US$600 million; due 2029; December 31, 2023 - US$600 million)	**864**	792
Unamortized deferred debt discount and debt issue costs	**(6)**	(9)
Current and long-term debt	**858**	1,124
Cash and cash equivalents	**(156)**	(160)
Net debt - C$(1)	**$ 702**	$ 964
Net debt - US$(1)	**$ 488**	$ 730

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

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



The Corporation's cash and cash equivalents were $156 million at December 31, 2024 and $160 million at December 31, 2023. Refer to the "Cash Flow Summary" section for further details.

Long-term debt decreased to US$600 million at December 31, 2024 from US$858 million at December 31, 2023.

The Corporation allocated free cash flow to both share repurchases and debt repayment from 2022 until its US$600 million net debt target was achieved in the third quarter of 2024. The Corporation then began returning 100% of free cash flow to shareholders through share repurchases and a quarterly base dividend. The Corporation's balance sheet strength and liquidity profile support enhanced distributions to shareholders with a continued emphasis on share repurchases.

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.

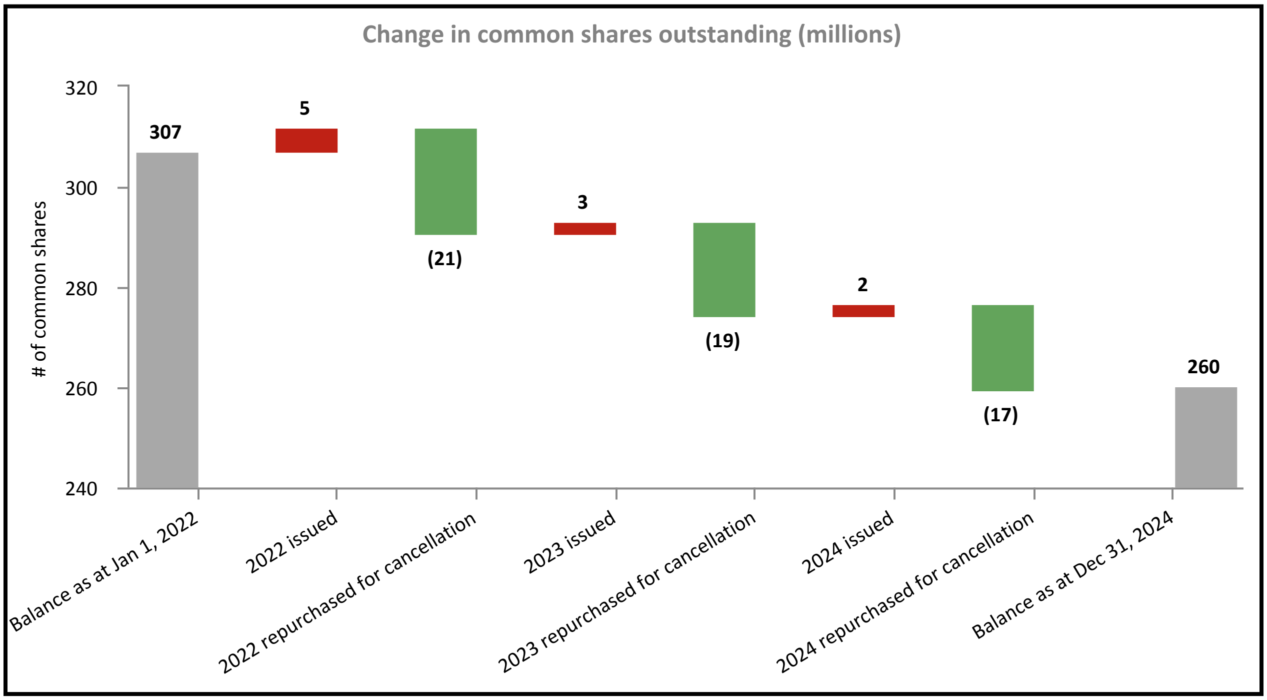
Cash dividends of $0.10 per share were declared on July 25, 2024 and November 5, 2024 with payments on October 15, 2024 and January 15, 2025, respectively.

On February 27, 2025, the Corporation's Board of Directors declared a $0.10 per share dividend payable on April 15, 2025 to shareholders of record at the close of business on March 20, 2025. All dividends paid by the Corporation are designated as eligible dividends for Canadian federal income tax purposes.

Declaration of dividends is at the discretion of the Board of Directors and will continue to be evaluated on a quarterly basis. 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.

Pursuant to its current normal course issuer bid ("NCIB"), the Corporation is purchasing for cancellation, from time to time, as it considers advisable, up to a maximum of 24,007,526 common shares of the Corporation. The NCIB became effective on March 11, 2024 and will terminate on March 10, 2025 or such earlier time as the NCIB is completed or terminated at the option of MEG. The Corporation intends to renew the NCIB for a one-year period, which will allow the repurchase of up to an additional 10% of MEG's public float, as defined by the Toronto Stock Exchange over this period.

During 2024, the Corporation repurchased for cancellation 17.0 million common shares under its NCIB program at a weighted-average price of $26.77 per share for a total cost of $454 million.



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 under the EDC Facility do not consume capacity of the revolving credit facility. The revolving credit facility and the EDC Facility have maturity dates of October 31, 2026 and are secured by substantially all the assets of the Corporation.

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 December 31, 2024, the Corporation had $600 million of unutilized capacity under the revolving credit facility and, with $256 million of issued letters of credit, had $344 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 contains no financial maintenance covenants nor is it secured on a *pari passu* basis with the revolving credit facility.

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

($millions)	**2024**	2023
Net cash provided by (used in):		
Operating activities	**$ 1,340**	$ 1,349
Investing activities	**(501)**	(478)
Financing activities	**(860)**	(896)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**17**	(7)
Change in cash and cash equivalents	**$ (4)**	$ (32)

Cash Flow – Operating Activities

Net cash provided by operating activities during 2024 decreased, compared to 2023, primarily due to increased royalties largely offset by higher bitumen realization after net transportation and storage expense and reduced working capital requirements.

Cash Flow – Investing Activities

Net cash used in investing activities increased $23 million during 2024, compared to 2023, primarily reflecting increased capital spending partially offset by reduced working capital requirements.

Cash Flow – Financing Activities

Net cash used in financing activities decreased $36 million during 2024, compared to 2023, primarily reflecting decreased free cash flow utilized for debt repayment partially offset by higher repurchase of shares and dividend payments.

12. RISK MANAGEMENT

Commodity Price Risk Management

The Corporation periodically enters financial commodity risk management contracts to protect and increase the predictability of cash flow, manage commodity input costs and support marketing asset optimization activities pursuant to Board approved policies. Financial commodity risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss).

Realized gains or losses on financial commodity risk management contracts result from settlements during the period. Unrealized gains or losses on financial commodity risk management contracts comprise changes in the mark-to-market position of the unsettled commodity risk management contracts, and offset the realized risk management gain (loss) recognized on contract settlements to determine total commodity risk management gains or losses recognized during the period.

($millions)	2024	2023
Realized commodity risk management loss	$ (29)	$ (28)
Unrealized commodity risk management gain (loss)	22	(4)
Commodity risk management loss	$ (7)	$ (32)

Equity Price Risk Management

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

($millions)	2024	2023(1)
Unrealized equity price risk management loss	$ —	$ 78
Realized equity price risk management gain	—	(87)
Equity price risk management gain	$ —	$ (9)

(1) As at March 31, 2023, all outstanding financial equity price risk management contracts were fully realized.

13. SHARES OUTSTANDING

At December 31, 2024, the Corporation had the following share capital instruments outstanding or exercisable:

(thousands)	Units
Common shares:	
Outstanding at December 31, 2023	274,642
Issued upon exercise of stock options	155
Issued upon vesting and release of equity-settled RSUs and PSUs	2,311
Repurchased for cancellation	(16,957)
Common shares outstanding at December 31, 2024	**260,151**
Convertible securities:	
Equity-settled RSUs and PSUs	**2,204**

At February 26, 2025, the Corporation had 256.8 million common shares outstanding and 2.2 million equity-settled RSUs and PSUs outstanding.

14. 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 December 31, 2024. 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]	$ 504	$ 506	$ 507	$ 512	$ 497	$ 4,685	$ 7,211
Diluent purchases[2][3]	266	72	65	66	65	32	566
Other operating commitments	20	19	10	9	6	58	122
Variable office lease costs	4	4	4	4	4	8	28
Capital commitments	74	—	—	—	—	—	74
Total Commitments	868	601	586	591	572	4,783	8,001
Other Obligations:							
Lease liabilities[5]	40	37	35	36	36	376	560
Long-term debt[4]	—	—	—	—	864	—	864
Interest on long-term debt[4]	51	51	51	51	6	—	210
Onerous contract[5]	11	11	11	11	3	—	47
Decommissioning obligation[5]	8	8	8	8	8	858	898
Total Commitments and Obligations	**$ 978**	**$ 708**	**$ 691**	**$ 697**	**$ 1,489**	**$ 6,017**	**$ 10,580**

(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) *During 2024, the Corporation executed a 5-year diluent supply commitment.*
(4) *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 December 31, 2024.*
(5) *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.

15. NON-GAAP AND OTHER FINANCIAL MEASURES

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

Adjusted Funds Flow and Free Cash Flow

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

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

	Three months ended December 31		Year ended December 31	
($millions)	**2024**	**2023**	**2024**	**2023**
Funds flow from operating activities	**$ 340**	$ 358	**$ 1,385**	$ 1,476
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management	**—**	—	**—**	13
Realized equity price risk management gain	**—**	—	**—**	(87)
Adjusted funds flow	**340**	358	**1,385**	1,402
Capital expenditures	**(172)**	(104)	**(548)**	(449)
Free cash flow	**$ 168**	$ 254	**$ 837**	$ 953

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	**December 31, 2024**	**December 31, 2023**
Long-term debt	**$ 858**	$ 1,124
Cash and cash equivalents	**(156)**	(160)
Net debt - C$	**$ 702**	$ 964
Net debt - US$	**$ 488**	$ 730

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 December 31		Year ended December 31	
($millions)	**2024**	**2023**	**2024**	**2023**
Revenues	**$ 1,147**	$ 1,444	**$ 5,149**	$ 5,653
Diluent expense	**(411)**	(471)	**(1,682)**	(1,691)
Transportation and storage expense	**(177)**	(148)	**(625)**	(600)
Purchased product	**(99)**	(334)	**(958)**	(1,400)
Operating expenses	**(72)**	(82)	**(290)**	(334)
Realized gain (loss) on commodity risk management	**(7)**	(9)	**(29)**	(28)
Cash operating netback	**$ 381**	$ 400	**$ 1,565**	$ 1,600

Blend Sales and Bitumen Realization

Blend sales and bitumen realization are non-GAAP financial measures, or ratios when expressed on a per barrel basis, and are used as a measure of the Corporation's marketing strategy by isolating petroleum revenue and costs associated with its produced and purchased products and excludes royalties. Their terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Blend sales per barrel is based on blend sales volumes and bitumen realization per barrel is based on bitumen sales volumes.

Revenues is an IFRS measure in the Corporation's consolidated statement of earnings 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 December 31				Year ended December 31			
	2024		**2023**		**2024**		**2023**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Revenues	**$ 1,147**		$ 1,444		**$ 5,149**		$ 5,653	
Power and transportation revenue	**(12)**		(19)		**(58)**		(117)	
Royalties	**132**		186		**591**		456	
Petroleum revenue	**1,267**		1,611		**5,682**		5,992	
Purchased product	**(99)**		(334)		**(958)**		(1,400)	
Blend sales	**1,168**	**$ 89.00**	1,277	$ 87.33	**4,724**	**$ 90.02**	4,592	$ 87.94
Diluent expense	**(411)**	**(7.42)**	(471)	(9.58)	**(1,682)**	**(7.90)**	(1,691)	(9.30)
Bitumen realization	**$ 757**	**$ 81.58**	$ 806	$ 77.75	**$ 3,042**	**$ 82.12**	$ 2,901	$ 78.64

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 December 31				Year ended December 31			
	2024		2023		2024		2023	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Transportation and storage expense	**$ (177)**	**$(19.01)**	$ (148)	$(14.23)	**$ (625)**	**$(16.86)**	$ (600)	$(16.27)
Power and transportation revenue	**$ 12**		$ 19		**$ 58**		$ 117	
Less power revenue	**(11)**		(19)		**(56)**		(114)	
Transportation revenue	**$ 1**	**$ 0.05**	$ —	$ —	**$ 2**	**$ 0.05**	$ 3	$ 0.09
Net transportation and storage expense	**$ (176)**	**$(18.96)**	$ (148)	$(14.23)	**$ (623)**	**$(16.81)**	$ (597)	$(16.18)

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 December 31				Year ended December 31			
	2024		2023		2024		2023	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Bitumen realization(1)	**$ 757**	**$ 81.58**	$ 806	$ 77.75	**$ 3,042**	**$ 82.12**	$ 2,901	$ 78.64
Net transportation and storage expense(1)	**(176)**	**(18.96)**	(148)	(14.23)	**(623)**	**(16.81)**	(597)	(16.18)
Bitumen realization after net transportation and storage expense	**$ 581**	**$ 62.62**	$ 658	$ 63.52	**$ 2,419**	**$ 65.31**	$ 2,304	$ 62.46

(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 December 31				Year ended December 31			
	2024		2023		2024		2023	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Non-energy operating costs	**$ (52)**	**$ (5.61)**	$ (48)	$ (4.64)	**$ (199)**	**$ (5.39)**	$ (185)	$ (5.01)
Energy operating costs	**(20)**	**(2.18)**	(34)	(3.25)	**(91)**	**(2.45)**	(149)	(4.03)
Operating expenses	**$ (72)**	**$ (7.79)**	$ (82)	$ (7.89)	**$ (290)**	**$ (7.84)**	$ (334)	$ (9.04)
Power and transportation revenue	**$ 12**		$ 19		**$ 58**		$ 117	
Less transportation revenue	**(1)**		—		**(2)**		(3)	
Power revenue	**$ 11**	**$ 1.28**	$ 19	$ 1.79	**$ 56**	**$ 1.52**	$ 114	$ 3.08
Operating expenses net of power revenue	**$ (61)**	**$ (6.51)**	$ (63)	$ (6.10)	**$ (234)**	**$ (6.32)**	$ (220)	$ (5.96)
Energy operating costs net of power revenue	**$ (9)**	**$ (0.90)**	$ (15)	$ (1.46)	**$ (35)**	**$ (0.93)**	$ (35)	$ (0.95)

Effective royalty rate

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

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

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

	Three months ended December 31		Year ended December 31	
($millions)	2024	2023	2024	2023
Bitumen realization	**$ 757**	$ 806	**$ 3,042**	$ 2,901
Transportation and storage expense	**(177)**	(148)	**(625)**	(600)
Transportation revenue	**1**	—	**2**	3
Bitumen realization after net transportation and storage expense	**$ 581**	$ 658	**$ 2,419**	$ 2,304
Royalties	**$ 132**	$ 186	**$ 591**	$ 456
Effective royalty rate	**22.7 %**	28.3 %	**24.4 %**	19.8 %

16. 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.

17. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter any significant related party transactions during 2024 and 2023, other than compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($millions)	**2024**	2023
Share-based compensation	**$ 11**	$ 21
Salaries and short-term employee benefits	**8**	5
	$ 19	$ 26

The decrease in share-based compensation to key management personnel in 2024 reflects fewer cash-settled and equity settled units outstanding in 2024, relative to 2023.

18. 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.

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

Risk Arising from Operations

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

- a decline in oil prices or widening of differentials between various crude oil grades;
- increases in the carbon price applied to GHG emissions above facility specific benchmarks;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher SOR, or the inability to recognize continued or increased efficiencies from the Corporation's production enhancement program which uses a combination of proprietary reservoir technologies (including eMSAGP) and enhanced completion designs, optimized inter-well spacing, short-cycle high return redevelopment projects and steam allocation techniques;
- reduced access to or an increase in the cost of diluent;
- an increase in the cost of natural gas;

- the reliability of MEG's facilities;
- the safety and reliability of the Access Pipeline, other pipelines, tankage and vessels that transport or stores MEG's products;
- the need to replace significant portions of existing wells, referred to as "workovers", or the need to drill additional wells;
- the cost to transport bitumen, diluent and bitumen blend, and the cost to dispose of certain by-products;
- the availability and cost of insurance and the inability to insure against certain types of losses;
- severe weather or catastrophic events such as fires, lightning, earthquakes, extreme cold weather, storms or explosions;
- seasonal weather patterns and the corresponding effects of the spring thaw on accessibility to MEG's properties;
- international and regional relations, and other geopolitical tensions and events, including war, international conflict, military action, regional hostilities, terrorism, economic sanctions, embargoes, trade disputes, tariffs, export taxes and curtailment on exports;
- the availability of water supplies and the ability to transmit power on the electrical transmission grid;
- changes in the political landscape and/or legal, tax and regulatory regimes in Canada, the United States and elsewhere;
- the ability to obtain further approvals and permits for MEG's future projects;
- the ability to attract or access capital as a result of changing investor priorities and trends, including as a result of climate change, ESG initiatives, the adoption of decarbonization policies and the general stigmatization of the oil and gas industry;
- the availability of pipeline capacity and other transportation and storage facilities for MEG's bitumen blend;
- refining markets for MEG's bitumen blend;
- increased royalty payments resulting from changes in regulatory regimes;
- inflationary pressures and increased supply costs;
- unavailability of, or increased cost of, skilled labour;
- unavailability of, or increased cost of, materials;
- the cost of chemicals used in MEG's operations, including, but not limited to, in connection with water and/or oil treatment facilities;
- the availability of and access to drilling equipment;
- access to Federal and Provincial Government support and the necessary policy and co-financing framework required to advance the Pathways Alliance projects;
- the cost of compliance with applicable regulatory regimes, including, but not limited to, environmental regulation; and
- the negative impacts of public health crises and the potential global economic impacts.

Concentration of Production in Single Project

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

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

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

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

- global energy policy, including (without limitation) the ability of the Organization of Petroleum Exporting Countries ("OPEC") and OPEC+ members, to set and maintain production levels and influence prices for crude oil;
- political instability and hostilities;
- domestic and foreign supplies of crude oil;
- the overall level of energy demand;
- weather conditions;
- government regulations including curtailment orders;
- taxes;
- potential for new tariffs or other trade restrictions which impact crude oil and bitumen;
- currency exchange rates;
- the availability of refining capacity and transportation infrastructure, including pipelines;
- the effect of worldwide environmental and/or energy conservation measures;
- the price and availability of alternative energy supplies;
- the risk of novel viruses (similar to COVID-19), including governmental policy and emergency response measures and related economic downturn related to same; and
- the overall global economic environment.

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

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

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

Risk Management Strategies

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

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

19. DISCLOSURE CONTROLS AND PROCEDURES

The Corporation’s Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”) have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation’s CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. The CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the Corporation and have concluded that the Corporation's disclosure controls and procedures were effective at December 31, 2024 for the foregoing purposes.

20. INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation’s financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The CEO’s and CFO’s evaluation concluded that internal controls over financial reporting were effective as of December 31, 2024.

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.

21. 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

22. ADVISORY

Forward-Looking Information

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

Forward-looking statements are often, but not always, identified by such words. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. In particular, and without limiting the foregoing, this document contains forward looking statements with respect to: the Corporation’s business strategy, focus and future plans; the Corporation’s 2025 operating and capital guidance, including its expectations regarding 2025 annual average production, capital expenditures and non-energy operating costs; 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 expected timeline, cost and productive capacity growth of the FEP; the reserves and reserve life of the Corporation's assets; 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 pay a cash dividend each quarter, subject to approval of the Corporation's board of directors; 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; and the Corporation's plan to renew its NCIB.

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 an energy company focused on in situ thermal oil production in the southern Athabasca oil region of Alberta, Canada. The Corporation is actively developing innovative enhanced oil recovery projects that utilize SAGD extraction methods to improve the economic recovery of oil. MEG transports and sells its thermal oil (known as AWB) to customers throughout North America and internationally. MEG is a member of the Pathways Alliance, a group of Canada's largest oil sands producers. The Corporation's common shares are listed on the Toronto Stock Exchange under the symbol "MEG".

Estimates of Reserves and Resources

For information regarding the Corporation's estimated reserves and resources, please refer to the Corporation's most recently filed AIF.

23. 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.

24. QUARTERLY SUMMARIES

	2024				2023			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**106**	167	136	98	103	249	136	81
Per share, diluted	**0.40**	0.62	0.50	0.36	0.37	0.86	0.47	0.28
Funds flow from operating activities	**340**	362	354	329	358	492	278	348
Per share, diluted	**1.29**	1.34	1.30	1.19	1.27	1.71	0.96	1.19
Adjusted funds flow[(1)]	**340**	362	354	329	358	492	278	274
Per share, diluted[(1)]	**1.29**	1.34	1.30	1.19	1.27	1.71	0.96	0.94
Capital expenditures	**172**	141	123	112	104	83	149	113
Free cash flow[(1)]	**168**	221	231	217	254	409	129	161
Per share, diluted[(1)]	**0.64**	0.82	0.85	0.78	0.90	1.42	0.45	0.55
Working capital	**300**	287	344	226	278	495	231	219
Net debt - US$[(1)]	**488**	478	634	687	730	885	994	1,020
Shareholders' equity	**4,553**	4,614	4,580	4,511	4,527	4,641	4,441	4,370
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**70.27**	75.09	80.57	76.96	78.32	82.26	73.78	76.13
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.56)**	(13.55)	(13.61)	(19.31)	(21.89)	(12.91)	(15.16)	(24.88)
AWB – Edmonton (US$/bbl)	**56.82**	60.62	65.99	55.96	54.53	67.88	56.41	48.50
Mainline heavy apportionment	**1 %**	2 %	5 %	28 %	21 %	1 %	1 %	12 %
C$ equivalent of 1US$ – average	**1.3991**	1.3636	1.3684	1.3488	1.3618	1.3410	1.3430	1.3520
Natural gas – AECO ($/mcf)	**1.61**	0.75	1.29	2.72	2.51	2.83	2.67	3.51
OPERATIONAL ($/bbl unless specified)								
Blend sales, net of purchased product – bbls/d	**142,595**	145,244	132,812	152,844	158,850	140,002	119,187	154,197
Diluent usage – bbls/d	**(41,774)**	(39,989)	(39,672)	(47,310)	(46,216)	(38,377)	(35,656)	(47,717)
Bitumen sales – bbls/d	**100,821**	105,255	93,140	105,534	112,634	101,625	83,531	106,480
Bitumen production – bbls/d	**100,139**	103,298	100,531	104,088	109,112	103,726	85,974	106,840
Steam-oil ratio (SOR)	**2.40**	2.36	2.44	2.37	2.28	2.28	2.25	2.25
Blend sales[(2)]	**89.00**	90.51	98.02	83.58	87.33	101.53	87.81	76.07
Diluent expense	**(7.42)**	(7.25)	(6.91)	(10.00)	(9.58)	(0.06)	(10.27)	(17.89)
Bitumen realization[(2)]	**81.58**	83.26	91.11	73.58	77.75	101.47	77.54	58.18
Net transportation and storage expense[(2)]	**(18.96)**	(17.65)	(17.27)	(13.48)	(14.23)	(16.72)	(19.90)	(14.78)
Bitumen realization after net transportation and storage expense[(2)]	**62.62**	65.61	73.84	60.10	63.52	84.75	57.64	43.40
Royalties	**(14.22)**	(17.45)	(19.12)	(13.35)	(17.92)	(19.45)	(7.69)	(3.18)
Non-energy operating costs[(3)]	**(5.61)**	(5.18)	(5.63)	(5.18)	(4.64)	(5.15)	(5.66)	(4.77)
Energy operating costs[(3)]	**(2.18)**	(1.70)	(2.13)	(3.74)	(3.25)	(3.42)	(3.92)	(5.57)
Power revenue	**1.28**	1.06	1.14	2.55	1.79	3.46	2.95	4.21
Realized gain (loss) on commodity risk management	**(0.80)**	(0.99)	(0.96)	(0.39)	(0.85)	(1.55)	(0.94)	0.23
Cash operating netback[(2)]	**41.09**	41.35	47.14	39.99	38.65	58.64	42.38	34.32
Revenues	**1,147**	1,265	1,373	1,364	1,444	1,438	1,291	1,480
Power sales price (C$/MWh)	**52.21**	53.64	45.57	102.53	81.66	156.04	150.19	162.90
Power sales (MW/h)	**108**	90	100	113	108	97	71	118
Average cost of diluent ($/bbl of diluent)	**106.91**	109.62	114.25	105.89	110.65	101.68	111.85	116.01
Average cost of diluent as a % of WTI	**109 %**	107 %	104 %	102 %	104 %	92 %	113 %	113 %
Depletion and depreciation rate per bbl of production	**16.37**	16.92	16.35	16.79	19.01	15.28	14.88	14.86
General and administrative expense per bbl of production	**1.85**	1.80	1.98	2.18	1.89	1.73	1.85	1.94
COMMON SHARES								
Shares outstanding, end of period (000)	**260,151**	266,035	270,142	272,376	274,642	283,290	285,566	288,614
Common share price ($) - close (end of period)	**23.60**	25.41	29.27	31.10	23.67	26.43	21.00	21.71

(1) Capital management measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.
(3) Supplementary financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.

During the eight most recent quarters the following items have had a significant impact on the Corporation's quarterly results:

- significant variability in blend sales pricing primarily due to high volatility in the price of WTI which ranged from a quarterly average of US$70.27/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$24.88/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 allowing the Corporation to return 100% of free cash flow to shareholders through share buybacks and a quarterly base dividend starting in the fourth quarter of 2024;
- 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;
- gains and losses on risk management contracts;
- changes in depletion and depreciation expense as a result of changes in production rates and future development cost estimates;
- changes in the Corporation's share price and the resulting impact on stock-based compensation and financial equity price risk management contracts; and
- planned turnaround, unplanned outages and other maintenance activities affecting production.

25. ANNUAL SUMMARIES

	2024	2023	2022	2021	2020	2019	2018[1]
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	**507**	569	902	283	(357)	(62)	(119)
Per share, diluted	**1.87**	1.98	2.92	0.91	(1.18)	(0.21)	(0.40)
Funds flow from operating activities	**1,385**	1,476	1,882	753	239	741	169
Per share, diluted	**5.13**	5.13	6.09	2.42	0.78	2.46	0.56
Adjusted funds flow[2]	**1,385**	1,402	1,934	826	281	724	175
Per share, diluted[2]	**5.13**	4.87	6.26	2.65	0.92	2.41	0.58
Capital expenditures	**548**	449	376	331	149	198	622
Free cash flow[2]	**837**	953	1,558	495	132	526	(447)
Per share, diluted[2]	**3.10**	3.31	5.05	1.59	0.43	1.75	(1.51)
Working capital	**300**	278	289	150	55	123	290
Net debt - US$[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$/bbl)	**59.84**	56.83	73.59	53.20	25.08	42.08	34.78
Mainline heavy apportionment	**9 %**	9 %	5 %	42 %	24 %	43 %	41 %
C$ 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 15 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.*
(4) *Supplementary financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.*

REPORT OF MANAGEMENT

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

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

The Corporation maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Corporation’s assets are properly accounted for and adequately safeguarded. Management’s evaluation concluded that the Corporation’s internal controls over financial reporting were effective as of December 31, 2024.

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

PricewaterhouseCoopers LLP, an independent firm of auditors, has been engaged, as approved by a vote of the shareholders at the Corporation’s most recent Annual General Meeting, to audit and provide their independent audit opinion on the Corporation’s consolidated financial statements as at and for the year ended December 31, 2024. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

/s/ Darlene Gates

Darlene Gates
President and Chief Executive Officer

/s/ Ryan Kubik

Ryan Kubik, CPA, CA
Chief Financial Officer

February 27, 2025

Independent auditor's report

To the Shareholders of MEG Energy Corp.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of MEG Energy Corp. and its subsidiaries (together, the Corporation) as at December 31, 2024 and 2023, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS Accounting Standards).

What we have audited
The Corporation's consolidated financial statements comprise:

- the consolidated balance sheets as at December 31, 2024 and 2023;
- the consolidated statements of earnings and comprehensive income for the years then ended;
- the consolidated statements of changes in shareholders' equity for the years then ended;
- the consolidated statements of cash flow for the years then ended; and
- the notes to the consolidated financial statements, comprising material accounting policy information and other explanatory information.

Basis for opinion

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

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

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

PricewaterhouseCoopers LLP
Suncor Energy Centre, 111 5th Avenue South West, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T.: +1 403 509 7500, F.: +1 403 781 1825, Fax to mail: ca_calgary_main_fax@pwc.com

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2024. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Key audit matter	How our audit addressed the key audit matter
The impact of proved bitumen reserves on crude oil assets *Refer to note 3 – Material accounting policies, note 4 – Significant accounting estimates, assumptions, and judgments, and note 7 – Property, plant and equipment to the consolidated financial statements.* The Corporation's net crude oil assets was $5,331 million as at December 31, 2024 and the related depletion and depreciation (D&D) expense was $603 million for the year then ended. Field production assets represent a portion of the crude oil assets and are depleted using the unit-of-production method based on estimates of proved bitumen reserves. Management applies significant judgment in developing the estimates of proved bitumen reserves. These estimates are based on estimated future prices, expected future rates of production and the cost and timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Corporation's estimates of proved bitumen reserves are generated by the Corporation's independent reserve engineers (management's experts). We considered this a key audit matter due to the significant judgment by management, including the use of management's experts, when developing the estimates of proved bitumen reserves, which led to a high degree of auditor judgment, subjectivity, and effort in performing audit procedures.	Our approach to addressing the matter included the following procedures, among others: • Tested how management developed the estimates of proved bitumen reserves and D&D expense, which included the following: – The work of management's experts was used in performing the procedures to evaluate the reasonableness of the estimates of proved bitumen reserves used to determine D&D expense. As a basis for using this work, the competence, capability and objectivity of management's experts was evaluated, the work performed was understood and the appropriateness of the work as audit evidence was evaluated. The procedures performed also included evaluation of the methods and assumptions used by management's experts, tests of the data used by management's experts and an evaluation of their findings. Evaluated the reasonableness of assumptions used in developing the underlying estimates, including: o estimated future prices by comparing those prices with other reputable third party industry forecasts; and

Key audit matter	How our audit addressed the key audit matter
	o expected future rates of production, and the cost and timing of future capital expenditures by considering the current and past performance of the Corporation, and whether these assumptions were consistent with evidence obtained in other areas of the audit. – Tested the data used in the determination of these estimates. – Recalculated the unit-of-production rates used to calculate depletion expense related to field production assets.

Other information

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The engagement partner on the audit resulting in this independent auditor's report is Ryan Lundeen.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
February 27, 2025

Consolidated Balance Sheet
(Expressed in millions of Canadian dollars)

As at December 31	Note	2024	2023
Assets			
Current assets			
Cash and cash equivalents	22	$ **156**	$ 160
Accrued revenue and accounts receivable	6	**440**	465
Inventories	7	**258**	235
Risk management	24	**—**	2
		854	862
Non-current assets			
Property, plant and equipment	8	**5,556**	5,683
Exploration and evaluation assets	9	**128**	128
Other assets	10	**206**	225
Total assets		$ **6,744**	$ 6,898
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	11	$ **471**	$ 499
Dividends payable		**26**	—
Interest payable		**22**	31
Current portion of provisions and other liabilities	13	**35**	30
Risk management	24	**—**	24
		554	584
Non-current liabilities			
Long-term debt	12	**858**	1,124
Provisions and other liabilities	13	**417**	486
Deferred income tax liability	14	**362**	177
Total liabilities		**2,191**	2,371
Shareholders' equity			
Share capital	15	**4,571**	4,845
Contributed surplus		**176**	180
Deficit		**(242)**	(531)
Accumulated other comprehensive income		**48**	33
Total shareholders' equity		**4,553**	4,527
Total liabilities and shareholders' equity		$ **6,744**	$ 6,898

Commitments and contingencies (Note 27)

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

These Consolidated Financial Statements were approved by the Corporation's Board of Directors on February 27, 2025.

/s/ Darlene Gates
Darlene Gates, Director

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

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

Year ended December 31	Note		2024		2023
Revenues					
Petroleum revenue, net of royalties	17	$	**5,091**	$	5,536
Power and transportation revenue	17		**58**		117
Revenues			**5,149**		5,653
Expenses					
Diluent expense			**1,682**		1,691
Transportation and storage expense			**625**		600
Operating expenses			**290**		334
Purchased product			**958**		1,400
Depletion and depreciation			**620**		596
General and administrative			**73**		69
Stock-based compensation	16		**24**		35
Net finance expense	19		**113**		149
Other	20		**(6)**		46
Commodity risk management loss	24		**7**		32
Foreign exchange (gain) loss	18		**67**		(22)
Earnings before income taxes			**696**		723
Income tax expense	14		**189**		154
Net earnings			**507**		569
Other comprehensive income, net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment			**15**		**(5)**
Comprehensive income		$	**522**	$	564
Net earnings per common share					
Basic	23	$	**1.89**	$	2.00
Diluted	23	$	**1.87**	$	1.98

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

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

	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2023	**$ 4,845**	**$ 180**	**$ (531)**	**$ 33**	**$ 4,527**
Stock-based compensation	**—**	**19**	**—**	**—**	**19**
Stock options exercised	**1**	**—**	**—**	**—**	**1**
RSUs and PSUs vested and released	**23**	**(23)**	**—**	**—**	**—**
Repurchase of shares for cancellation	**(298)**	**—**	**(156)**	**—**	**(454)**
Tax on repurchases of equity	**—**	**—**	**(9)**	**—**	**(9)**
Dividends	**—**	**—**	**(53)**	**—**	**(53)**
Comprehensive income	**—**	**—**	**507**	**15**	**522**
Balance as at December 31, 2024	**$ 4,571**	**$ 176**	**$ (242)**	**$ 48**	**$ 4,553**
Balance as at December 31, 2022	$ 5,164	$ 169	$ (988)	$ 38	$ 4,383
Stock-based compensation	—	25	—	—	25
Stock options exercised	2	(1)	—	—	1
RSUs vested and released	13	(13)	—	—	—
Repurchase of shares for cancellation	(334)	—	(112)	—	(446)
Comprehensive income	—	—	569	(5)	564
Balance as at December 31, 2023	$ 4,845	$ 180	$ (531)	$ 33	$ 4,527

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

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

Year ended December 31	Note	2024	2023
Cash provided by (used in):			
Operating activities			
Net earnings		**$ 507**	$ 569
Adjustments for:			
Deferred income tax expense	14	**185**	152
Depletion and depreciation	8, 10	**620**	596
Stock-based compensation	16	**19**	103
Unrealized loss (gain) on foreign exchange	18	**65**	(20)
Unrealized net loss (gain) on commodity risk management	24	**(22)**	4
Debt extinguishment expense	19	**7**	12
Onerous contract expense	20	**(3)**	47
Accretion on provisions	13	**14**	12
Other		**4**	4
Decommissioning expenditures	13	**(5)**	(3)
Payments on onerous contract	13	**(8)**	—
Net change in long-term incentive compensation liability		**2**	—
Funds flow from operating activities		**1,385**	1,476
Net change in non-cash working capital items	22	**(45)**	(127)
Net cash provided by (used in) operating activities		**1,340**	1,349
Investing activities			
Capital expenditures	8	**(548)**	(449)
Other		**—**	1
Net change in non-cash working capital items	22	**47**	(30)
Net cash provided by (used in) investing activities		**(501)**	(478)
Financing activities			
Repurchase and redemption of long-term debt	12	**(351)**	(437)
Debt redemption premium	12	**(7)**	(9)
Repurchase of shares	15	**(454)**	(446)
Tax on share repurchases	15	**(9)**	—
Issue of shares, net of issue costs		**1**	1
Receipts on leased assets	22	**2**	2
Payments on leased liabilities	22	**(15)**	(18)
Payments of dividends		**(27)**	—
Net change in non-cash working capital items	22	**—**	11
Net cash provided by (used in) financing activities		**(860)**	(896)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**17**	(7)
Change in cash and cash equivalents		**(4)**	(32)
Cash and cash equivalents, beginning of year		**160**	192
Cash and cash equivalents, end of period		**$ 156**	$ 160

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

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange under the symbol "MEG". The Corporation owns a 100% interest in over 410 square miles of mineral leases in the southern Athabasca oil region of Alberta, Canada and is primarily engaged in *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 consolidated financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards"). The consolidated financial statements have been prepared on the historical cost basis, except as detailed in the material accounting policies disclosed in Note 3. These audited consolidated financial statements were approved by the Corporation's Board of Directors on February 27, 2025.

3. MATERIAL ACCOUNTING POLICIES

a. Principles of consolidation

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

b. Functional and presentation currency

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

c. Financial instruments

Financial assets are initially measured at amortized cost and are derecognized when the rights to receive cash flows have expired or when the Corporation has transferred substantially all risks and rewards of ownership.

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

Derivative financial instruments are recognized at fair value. Transaction costs are expensed in net earnings. Gains and losses arising from changes in fair value are recognized in net earnings in the period in which they arise.

Financial liabilities are classified as current except where an unconditional right to defer payment beyond 12 months exists. Derivative financial instruments are classified as current or non-current based on the contractual terms specific to the instrument.

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

d. Cash and cash equivalents

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

e. Inventories

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

f. Property, plant and equipment

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

i. Crude oil

Crude oil assets consist mainly of field production assets and major facilities and equipment. Planned major inspections, overhaul and turnaround activities, and the acquisition, construction, and development of oil sands properties and bitumen reserves, including directly attributable overhead and administrative costs, related borrowing costs and estimates of decommissioning costs are capitalized.

Field production assets are depleted using the unit-of-production method based on estimated proved bitumen reserves. Estimated future development costs required to develop and produce the proved bitumen reserves are also included in the costs subject to depletion. These estimates are reviewed by independent reserve engineers at least annually.

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

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

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

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

g. Exploration and evaluation assets

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

E&E assets are assessed for impairment if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. Also, if sufficient data exists to determine technical feasibility and commercial viability of extracting a mineral resource and proved or probable bitumen reserves exist, E&E assets are tested for impairment upon reclassification to property, plant and equipment. If it is determined that an E&E asset is not technically feasible or commercially viable or facts and circumstances suggest that the carrying amount exceeds the recoverable amount, the unrecoverable costs are charged to expense.

h. Leases

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

As Lessee

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

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

The ROU asset is depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. The ROU asset may be adjusted for certain re-measurements of the lease liability and impairment losses.

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

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

i. Impairments

PP&E and E&E assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated. Proved plus probable bitumen reserve estimates reported by independent reserve engineers are used in calculating recoverable amounts for impairment testing. E&E assets are also assessed for impairment immediately prior to being reclassified to PP&E.

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

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

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

j. Provisions

i. Decommissioning provision

The Corporation's activities give rise to dismantling, decommissioning and restoration obligations. A liability and corresponding PP&E asset are recorded for the estimated cost of those decommissioning and restoration obligations. The estimated cost is updated at least annually.

Increases in the decommissioning provision due to the passage of time are recognized in net finance expense, and changes in the estimated future cash flows are capitalized. Actual costs incurred for dismantling, decommissioning, and restoration activities reduce the decommissioning provision.

ii. Onerous contracts

A provision for an onerous contract is recognized when the unavoidable cost of meeting the obligations under the contract exceed the economic benefits expected to be derived from the contract. Onerous contracts are recorded at the present value of future cash flows, and increases due to the passage of time are recognized in net finance expense. The net amount of actual costs incurred are charged against the onerous contract provision.

k. Share based payments

The Corporation’s share-based compensation plans include equity-settled awards and cash-settled awards. The associated costs are recorded as stock-based compensation expense.

i. Equity-settled

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

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

ii. Cash-settled

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

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

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

l. Revenue recognition

The Corporation earns revenue primarily from the sale of crude oil, with power revenue earned from excess power generation.

i. Petroleum revenue and royalties

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

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

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

ii. Power revenue

Revenue from power generated in excess of the Corporation's internal requirements is recognized upon delivery from the Christina Lake Project plant gate, at which point, control is transferred to the customer on the power grid. Revenues are earned at prevailing market prices for each megawatt hour produced.

m. Deferred income taxes

The Corporation follows the liability method of accounting for income taxes. Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted as at the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority.

n. Net earnings (loss) per share

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

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

4. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGMENTS

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

a. Property, plant and equipment (PP&E)

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

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

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

b. Exploration and evaluation (E&E) assets

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

c. Bitumen reserves

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

d. Decommissioning provision

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

e. Impairments

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

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

f. Stock-based compensation

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

g. Deferred income taxes

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

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

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

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

h. Leases

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

When a lease contract contains an option to extend or terminate a lease, the Corporation must use its best estimate to determine the appropriate lease term. Management must consider all facts and circumstances to determine if there is an economic benefit to an extension or a termination option. The lease term must be reassessed if a significant event or change in circumstance occurs.

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

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

5. 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.

6. ACCRUED REVENUE AND ACCOUNTS RECEIVABLE

As at December 31	**2024**	**2023**
Accrued revenue	**$ 411**	$ 428
Accounts receivable	**9**	21
Deposits and advances	**19**	14
Current portion of sublease receivable	**1**	2
	$ 440	$ 465

7. INVENTORIES

As at December 31	2024	2023
Bitumen blend	**$ 221**	$ 196
Diluent	**17**	23
Material and supplies	**20**	16
	$ 258	$ 235

8. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Right-of-use assets	Corporate assets	Total
Cost				
Balance as at December 31, 2022	$ 9,912	$ 277	$ 79	$ 10,268
Additions	449	31	—	480
Change in decommissioning provision	35	—	—	35
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**
Accumulated depletion and depreciation				
Balance as at December 31, 2022	$ 4,377	$ 70	$ 58	$ 4,505
Depletion and depreciation	577	15	3	595
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**
Carrying amounts				
Balance as at December 31, 2023	$ 5,442	$ 223	$ 18	$ 5,683
Balance as at December 31, 2024	**$ 5,331**	**$ 211**	**$ 14**	**$ 5,556**

At December 31, 2024, PP&E was assessed for indicators of impairment and none were identified. Assets under construction and not available for use as at December 31, 2024 totaled $44 million (as at December 31, 2023 - $13 million).

9. EXPLORATION AND EVALUATION ASSETS

As at December 31, 2024, 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, 2023 – $128 million). These assets were assessed for indicators of impairment at December 31, 2024 and none were identified.

10. OTHER ASSETS

As at December 31	2024	2023
Non-current pipeline linefill[a]	**$ 189**	$ 206
Finance sublease receivables	**8**	10
Prepaid transportation costs	**7**	8
Intangible assets	**3**	3
	207	227
Less current portion, included in accrued revenue and accounts receivable	**(1)**	(2)
	$ 206	$ 225

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.

11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31	2024	2023
Trade payables and other	**$ 455**	$ 475
Current liability for cash-settled stock-based compensation	**16**	24
	$ 471	$ 499

12. LONG-TERM DEBT

As at December 31	2024	2023
Unsecured:		
7.125% senior unsecured notes (December 31, 2024 - $US nil; December 31, 2023 - US$258 million)[a]	**$ —**	$ 341
5.875% senior unsecured notes (December 31, 2024 - US$600 million; due 2029; December 31, 2023 - US$600 million)[b]	**864**	792
	864	1,133
Less unamortized deferred debt discount and debt issue costs	**(6)**	(9)
	$ 858	$ 1,124

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.4405 (December 31, 2023 – US$1 = C$1.3205).

a. Effective January 31, 2020, the Corporation issued US$1.2 billion in aggregate principal amount of 7.125% senior unsecured notes, with a maturity of February 1, 2027. In 2023, the Corporation repurchased and extinguished US$322 million of outstanding notes at a weighted average price of 101.7% plus accrued and unpaid interest. In 2024, the remaining US$258 million of outstanding notes were repurchased and extinguished at a weighted average price of 101.8% plus accrued and unpaid interest. For the year ended December 31, 2024, the Corporation recognized debt extinguishment expense of $7 million (year ended December 31, 2023 - $12 million) in net finance expense.

b. Effective February 2, 2021, the Corporation issued US$600 million in aggregate principal amount of 5.875% senior unsecured notes, with a maturity date of February 1, 2029. Interest is paid semi-annually in February and August. No principal payments are required until maturity on February 1, 2029. The Corporation has deferred the associated debt issue costs of $10 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

On June 24, 2022, the Corporation amended and restated its revolving credit facility and its letters of credit facility guaranteed by Export Development Canada ("EDC Facility") and extended the maturity date of each facility to October 31, 2026. Total credit available under the two facilities is $1.2 billion and is comprised of $600 million under the revolving credit facility and $600 million under the EDC Facility. Letters of credit under the EDC Facility do not consume capacity of the revolving credit facility. The revolving credit facility and EDC Facility are secured by substantially all the assets of the Corporation.

The revolving credit facility has a modified covenant-lite structure, meaning it contains 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 first lien net debt to last twelve month EBITDA ratio of 3.50 or less. Under the Corporation's credit facilities, first lien net debt is calculated as debt under the credit facilities plus other debt that is secured on a pari passu basis with the credit facilities, less cash-on-hand. The financial maintenance covenant, if triggered, will be tested quarterly. Issued letters of credit are not included in the calculation of this ratio. The Corporation continues to have no first lien debt outstanding.

At December 31, 2024, the Corporation had $600 million of unutilized capacity under the $600 million revolving credit facility and the Corporation had $344 million (as at December 31, 2023 $235 million) of unutilized capacity under the $600 million EDC Facility.

13. PROVISIONS AND OTHER LIABILITIES

As at December 31	**2024**	**2023**
Lease liabilities[(a)]	**$ 247**	$ 259
Decommissioning provision[(b)]	**161**	210
Onerous contract[(c)]	**42**	47
Long-term incentive compensation liability	**2**	—
Provisions and other liabilities	**452**	516
Less current portion	**(35)**	(30)
Non-current portion	**$ 417**	$ 486

a. Lease liabilities:

As at December 31	**2024**	**2023**
Balance, beginning of period	**$ 259**	$ 244
Modification	**—**	33
Payments	**(40)**	(41)
Interest expense	**25**	24
Foreign exchange impact	**3**	(1)
Balance, end of period	**247**	259
Less current portion	**(16)**	(15)
Non-current portion	**$ 231**	$ 244

The Corporation's minimum lease payments are as follows:

As at December 31		2024
Within one year	$	39
Later than one year but not later than five years		156
Later than five years		378
Minimum lease payments		573
Amounts representing finance charges		(326)
Net minimum lease payments	$	247

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 December 31		2024		2023
Balance, beginning of period	$	210	$	166
Changes in estimated life and estimated future cash flows		(41)		6
Changes in discount rates		(15)		30
Liabilities settled		(5)		(3)
Accretion		12		11
Balance, end of period		161		210
Less current portion		(8)		(6)
Non-current portion	$	153	$	204

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 $898 million (December 31, 2023 – $831 million). At December 31, 2024, the Corporation estimated the net present value of the decommissioning obligations using a weighted-average credit-adjusted risk-free rate of 8.5% (December 31, 2023 – 8.0%) and an inflation rate of 2.1% (December 31, 2023 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2023 - periods up to the year 2066).

c. Onerous contract:

As at December 31		2024		2023
Balance, beginning of period	$	47	$	—
Modification		(3)		—
Payments		(8)		—
Accretion		2		—
Foreign exchange impact		4		—
Recognition		—		47
Balance, end of period		42		47
Less current portion		(11)		(9)
Non-current portion	$	31	$	38

The onerous contract liability represents the present value of the estimated future cash flows with a remaining term of 4.25 years and relates to the assignment of an onerous marketing contract.

14. INCOME TAX

Year ended December 31	2024	2023
Earnings before income taxes	$ 696	$ 723
Statutory income tax rate	23 %	23 %
Expected income tax expense	160	166
Add (deduct) the tax effect of:		
Non-taxable loss (gain) on foreign exchange	10	(3)
Taxable capital loss (gain) not recognized	10	(3)
Adjustments relating to prior periods	9	(6)
Income tax expense	$ 189	$ 154
Current income tax expense	$ 4	$ 2
Deferred income tax expense	185	152
Income tax expense	$ 189	$ 154

As at December 31, 2024, the Corporation recognized a deferred tax liability of $362 million (December 31, 2023 - $177 million).

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

Deferred tax assets	Tax losses	Risk management	Decommissioning provision	Lease liabilities	Other	Total
Balance as at December 31, 2022	$ 944	$ (14)	$ 38	$ 48	$ 54	$ 1,070
Credited (charged) to earnings	(202)	19	11	2	—	(170)
Balance as at December 31, 2023	742	5	49	50	54	900
Credited (charged) to earnings	(215)	(5)	(25)	(6)	(2)	(253)
Balance as at December 31, 2024	**$ 527**	**$ —**	**$ 24**	**$ 44**	**$ 52**	**$ 647**

Deferred tax liabilities	Property, plant and equipment	Total
Balance as at December 31, 2022	$ (1,094)	$ (1,094)
Credited (charged) to earnings	17	17
Balance as at December 31, 2023	(1,077)	(1,077)
Credited (charged) to earnings	68	68
Balance as at December 31, 2024	**$ (1,009)**	**$ (1,009)**

As at December 31, 2024, the Corporation had approximately $3.7 billion of available Canadian tax pools including $2.3 billion of non-capital losses and $0.2 billion of capital losses (December 31, 2023 - $4.6 billion in available Canadian tax pools including $3.2 billion of non-capital losses and $0.2 billion of capital losses). The $2.3 billion of non-capital loss carry forward balances expire as follows:

	2035	2036	2037	2038	2039	Thereafter	Total
Non-capital loss carry forward balances	$ 680	$ 860	$ 400	$ 95	$ —	$ 262	$ 2,297

As at December 31, 2024, the Corporation had not recognized the tax benefit related to $224 million of realized and unrealized taxable capital foreign exchange losses (December 31, 2023 - $203 million).

15. 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:

	2024		2023	
	Number of shares (thousands)	**Amount**	**Number of shares (thousands)**	**Amount**
Balance, beginning of year	**274,642**	**$ 4,845**	291,081	$ 5,164
Issued upon exercise of stock options	**155**	**1**	139	2
Issued upon vesting and release of equity-settled RSUs and PSUs	**2,311**	**23**	2,377	13
Repurchase of shares for cancellation	**(16,957)**	**(298)**	(18,955)	(334)
Balance, end of period	**260,151**	**$ 4,571**	274,642	$ 4,845

On March 6, 2024, 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 24,007,526 common shares of the Corporation. The NCIB became effective on March 11, 2024 and will terminate on March 10, 2025 or such earlier time as the NCIB is completed or terminated at the option of MEG.

For the year ended December 31, 2024, the Corporation repurchased for cancellation 17.0 million common shares under its NCIB at a weighted-average price of $26.77 per share for a total cost of $454 million. Share capital was reduced by $298 million, reflecting the average carrying value of $17.58 per share. Retained earnings was reduced by $156 million for the repurchase price of shares above the carrying value. A 2% tax levied on share repurchases totaling $9 million was also recorded as a reduction to retained earnings.

For the year ended December 31, 2023, the Corporation repurchased for cancellation 19.0 million common shares under its NCIB at a weighted average price of $23.54 per share for a total cost of $446 million. Share capital was reduced by $334 million, reflecting the average carrying value of $17.67 per share. Retained earnings was reduced by $112 million for the repurchase price of shares above the carrying value.

16. STOCK-BASED COMPENSATION

The Corporation has a number of stock-based compensation plans which include stock options, RSUs, PSUs and DSUs. Further detail on each of these plans is outlined below.

a. Stock-based compensation

Year ended December 31	2024	2023
Cash-settled expense[(i)]	$ 5	$ 19
Equity-settled expense	19	25
Unrealized equity price risk management (gain) loss[(ii)]	—	78
Realized equity price risk management (gain) loss[(ii)]	—	(87)
Stock-based compensation	$ 24	$ 35

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

(ii) Relates to financial equity price risk management contracts entered to manage the Corporation's exposure to cash-settled RSUs and PSUs vesting between 2021 and 2023 granted under the Corporation's stock-based compensation plans. Amounts were unrealized until vesting of the related units occurred. All financial equity price risk management contracts were fully realized as at March 31, 2023. See note 24(d) for further details.

b. Cash-settled plans

i. Restricted share units and performance share units:

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

Cash-settled RSUs and PSUs outstanding:

Year ended December 31 (expressed in thousands)	2024	2023
Outstanding, beginning of year	—	4,413
Granted[(i)]	293	—
Vested and released	—	(4,165)
Forfeited	(71)	(248)
Outstanding, end of year	222	—

(i) Includes units added by dividend reinvestments

At December 31, 2024, the Corporation recognized a liability of $2 million relating to the fair value of cash-settled PSUs (December 31, 2023 – $nil) which is included within provisions and other liabilities.

ii. Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of DSUs to directors of the Corporation. A DSU represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in common shares purchased in the open market. DSUs vest immediately when granted and are redeemed on the earlier of (a) December 15 of the first calendar year starting after the date the holder ceases to be a Director of the Corporation of the Corporation, and (b) the fifth business day following each of the redemption dates elected by such holder.

DSUs outstanding:

Year ended December 31 (expressed in thousands)	2024	2023
Outstanding, beginning of year	**1,033**	1,148
Granted[(i)]	**32**	46
Vested and released	**(404)**	(161)
Outstanding, end of year	**661**	1,033

(i) Includes units added by dividend reinvestments

At December 31, 2024, the Corporation recognized a liability of $16 million relating to the fair value of cash-settled DSUs (December 31, 2023 – $24 million) which is included within accounts payable and accrued liabilities.

c. Equity-settled plans

i. As at December 31, 2024 there were no stock options outstanding (December 31, 2023 - 155 stock options outstanding), and, there were no stock options granted during the years ended December 31, 2024 and December 31, 2023.

ii. Restricted share units and performance share units:

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

Equity-settled RSUs and PSUs outstanding:

Year ended December 31 (expressed in thousands)	2024	2023
Outstanding, beginning of year	**3,698**	5,131
Granted[(i)]	**991**	1,277
Vested and released	**(2,312)**	(2,377)
Forfeited	**(173)**	(333)
Outstanding, end of year	**2,204**	3,698

(i) Includes units added by PSU performance factors and dividend reinvestments

Equity-settled RSUs and PSUs granted during the year ended December 31, 2024 had a weighted average fair value of $24.82 per share (year ended December 31, 2023 - $22.07 per share).

17. REVENUES

Year ended December 31	2024	2023
Sales from:		
Production	**$ 4,704**	$ 4,548
Purchased product(i)	**978**	1,444
Petroleum revenue	**$ 5,682**	$ 5,992
Royalties	**(591)**	(456)
Petroleum revenue, net of royalties	**$ 5,091**	$ 5,536
Power revenue	**$ 56**	$ 114
Transportation revenue	**2**	3
Power and transportation revenue	**$ 58**	$ 117
Revenues	**$ 5,149**	$ 5,653

(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:

	Year ended December 31					
	2024			2023		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	**$ 1,616**	**$ 246**	**$ 1,862**	$ 1,318	$ 267	$ 1,585
United States	**3,088**	**732**	**3,820**	3,230	1,177	4,407
	$ 4,704	**$ 978**	**$ 5,682**	$ 4,548	$ 1,444	$ 5,992

For the year ended December 31, 2024, power and transportation revenue of $58 million was attributed to Canada (year ended December 31, 2023 – $117 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 December 31	2024	2023
Petroleum revenue	**$ 409**	$ 424
Power and transportation revenue	**2**	4
Total revenue-related assets	**$ 411**	$ 428

Revenue-related receivables are typically settled within 30 days. At December 31, 2024 and December 31, 2023, there was no material expected credit loss recorded against revenue-related receivables.

18. FOREIGN EXCHANGE (GAIN) LOSS

Year ended December 31	2024	2023
Unrealized foreign exchange (gain) loss on:		
Long-term debt	$ 82	$ (26)
US$ denominated cash and cash equivalents	(17)	6
Unrealized net (gain) loss on foreign exchange	65	(20)
Realized (gain) loss on foreign exchange	2	(2)
Foreign exchange (gain) loss	$ 67	$ (22)

C$ equivalent of 1 US$		
Beginning of period	1.3205	1.3534
End of period	1.4405	1.3205

19. NET FINANCE EXPENSE

Year ended December 31	2024	2023
Interest expense on long-term debt	$ 59	$ 90
Interest expense on lease liabilities	25	24
Credit facility fees	16	18
Interest income	(8)	(6)
Net interest expense	92	126
Debt extinguishment expense	7	12
Accretion on provisions	14	11
Net finance expense	$ 113	$ 149

During the year ended December 31, 2024, debt extinguishment expense of $7 million was recognized, which was associated with the 7.125% senior unsecured note redemptions.

For the year ended December 31, 2023, debt extinguishment expense of $12 million was recognized in association with the repurchase and extinguishment of US$322 million (approximately $437 million) of the Corporation's 7.125% senior unsecured notes, which included a cumulative debt redemption premium of $9 million and associated amortized deferred debt issue costs of $3 million.

20. OTHER (INCOME) EXPENSE

Year ended December 31	2024	2023
Onerous contract expense (recovery)(i)	$ (3)	$ 47
Third party camp recovery	(3)	(1)
Other (income) expense	$ (6)	$ 46

(i) During the year ended December 31, 2023, the Corporation recognized an onerous contract expense to reflect the estimated discounted future cash flows associated with a marketing transportation contract.

21. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the years ended December 31, 2024 and 2023, other than compensation of key management personnel. The Corporation considers directors and officers of the Corporation as key management personnel.

Year ended December 31	2024	2023
Share-based compensation	**$ 11**	$ 21
Salaries and short-term employee benefits	**8**	5
	$ 19	$ 26

22. SUPPLEMENTAL CASH FLOW DISCLOSURES

Year ended December 31	2024	2023
Cash provided by (used in):		
Accrued revenue and accounts receivable	**$ 34**	$ 23
Inventories[a]	**9**	(83)
Accounts payable and accrued liabilities	**(32)**	(73)
Interest payable	**(9)**	(13)
	$ 2	$ (146)
Changes in non-cash working capital relating to:		
Operating	**$ (45)**	$ (127)
Investing	**47**	(30)
Financing	**—**	11
	$ 2	$ (146)
Cash and cash equivalents:[b]		
Cash	**$ 156**	$ 160
Cash equivalents	**—**	—
	$ 156	$ 160
Cash interest paid	**$ 69**	$ 103

a. Cash provided by (used in) inventories during the year ended December 31, 2024 excludes a $26 million reclassification of pipeline linefill from non-current assets to current inventories.

b. As at December 31, 2024, $131 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (December 31, 2023 – $102 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$1.4405 (December 31, 2023 – US$1 = C$1.3205).

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, 2022	$ 12	$ 244	$ 1,581
Financing cash flow changes:			
Receipts on leased assets	(2)	—	—
Payments on leased liabilities	—	(18)	—
Repayment and redemption of long-term debt	—	—	(437)
Debt redemption premium and refinancing costs	—	—	(9)
Other cash and non-cash changes:			
Interest payments on lease liabilities	—	(23)	—
Interest expense on lease liabilities	—	24	—
Modification of lease liabilities	—	33	
Unrealized (gain) loss on foreign exchange	—	(1)	(26)
Debt extinguishment expense	—	—	12
Amortization of deferred debt discount and debt issue costs	—	—	3
Balance as at December 31, 2023	$ 10	$ 259	$ 1,124
Financing cash flow changes:			
Receipts on leased assets	**(2)**	**—**	**—**
Payments on leased liabilities	**—**	**(15)**	**—**
Repayment and redemption of long-term debt	**—**	**—**	**(351)**
Debt redemption premium	**—**	**—**	**(7)**
Other cash and non-cash changes:			
Interest payments on lease liabilities	**—**	**(25)**	**—**
Interest expense on lease liabilities	**—**	**25**	**—**
Unrealized loss on foreign exchange	**—**	**3**	**82**
Debt extinguishment expense	**—**	**—**	**7**
Amortization of deferred debt discount and debt issue costs	**—**	**—**	**3**
Balance as at December 31, 2024	**$ 8**	**$ 247**	**$ 858**

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

23. NET EARNINGS PER COMMON SHARE

Year ended December 31	2024	2023
Net earnings	**$ 507**	$ 569
Weighted average common shares outstanding (millions)[(a)]	**268**	285
Dilutive effect of stock options and equity-settled RSUs and PSUs (millions)	**2**	3
Weighted average common shares outstanding – diluted (millions)	**270**	288
Net earnings per share, basic	**$ 1.89**	$ 2.00
Net earnings per share, diluted	**$ 1.87**	$ 1.98

a. Weighted average common shares outstanding for the year ended December 31, 2024 include 184,097 PSUs vested but not yet released (year ended December 31, 2023 - 519,160 PSUs vested but not yet released).

24. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments recognized on the consolidated balance sheet are comprised of cash and cash equivalents, accrued revenue and accounts receivable, 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, accrued revenue and accounts receivable, accounts payable and accrued liabilities, dividends payable and interest payable included on the consolidated balance sheet approximates the fair values of the respective assets and liabilities due to the short-term nature of those instruments.

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

As at December 31	**2024**		**2023**	
	Carrying amount	**Fair value**	**Carrying amount**	**Fair value**
Recurring measurements:				
Financial assets				
Commodity risk management contracts	**$ —**	**$ —**	$ 2	$ 2
Financial liabilities				
Long-term debt (Note 12)	**$ 864**	**$ 841**	$ 1,133	$ 1,108
Commodity risk management contracts	**$ —**	**$ —**	$ 24	$ 24

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker. The fair value was determined based on estimates as at December 31, 2024 and is expected to fluctuate overtime.

The fair value of risk management contracts is derived using quoted prices in an active market from a third-party independent broker. Management's assumptions rely on external observable market data including forward prices for commodities and foreign exchange rates. The observable inputs may be adjusted using certain methods, which include extrapolation to the end of the term of the contract.

b. Risk management:

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

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

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

As at December 31		2024		2023
Risk management assets (liabilities)	$	**(22)**	$	60
Realized risk management (gain) loss on:				
Equity price risk management contracts		—		(87)
Commodity risk management contracts		**29**		28
Change in fair value on:				
Equity price risk management contracts[(i)]		—		9
Commodity risk management contracts[(ii)]		**(7)**		(32)
Risk management assets (liabilities)	$	—	$	(22)

(i) Represents total equity price risk management (gain) loss recognized within stock-based compensation expense.
(ii) Represents total commodity risk management (gain) loss.

c. Commodity risk management

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

Year ended December 31		2024		2023
Realized loss (gain) on commodity risk management	$	**29**	$	28
Unrealized loss (gain) on commodity risk management		**(22)**		4
Commodity risk management loss	$	**7**	$	32

As at December 31, 2024, the Corporation has no outstanding commodity risk contracts.

d. Equity price risk management:

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

Year ended December 31		2024		2023[(1)]
Unrealized equity price risk management (gain) loss	$	—	$	78
Realized equity price risk management gain		—		(87)
Equity price risk management gain	$	—	$	(9)

(1) As at March 31, 2023, all outstanding financial equity price risk management contracts were fully realized.

e. Foreign currency risk management

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the fair value or future cash flows of the Corporation's financial assets or liabilities. The

Corporation has U.S. dollar denominated long-term debt as described in Note 12. As at December 31, 2024, a $0.01 change in the Canadian dollar to U.S. dollar exchange rate would have resulted in a change to the carrying value of long-term debt and a corresponding change to earnings (loss) before income tax of C$6 million (December 31, 2023 - C$9 million).

f. Credit risk management:

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all accounts receivable. 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 accounts receivable. As at December 31, 2024, the Corporation’s estimated maximum exposure to credit risk related to accounts receivable, deposits and advances was $438 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, along with adjusted funds flow, are used to fund expenses and 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. None of the investments are past their maturity or considered impaired. The Corporation’s estimated maximum exposure to credit risk related to its cash and cash equivalents is $156 million.

g. 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, 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. 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 only long-term debt maturity. None of the Corporation’s outstanding long-term debt contains 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.

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

As at December 31, 2024		Total		Less than 1 year		1 - 3 years		4 - 5 years		More than 5 years
Long-term debt	$	864	$	—	$	—	$	864	$	—
Interest on long-term debt		210		51		102		57		—
Lease liabilities		560		40		72		72		376
Accounts payable and accrued liabilities		471		471		—		—		—
Dividends payable		26		26		—		—		—
	$	2,131	$	588	$	174	$	993	$	376

25. GEOGRAPHICAL DISCLOSURE

As at December 31, 2024, the Corporation had non-current liabilities related to operations in the United States of $14 million (December 31, 2023 – non-current assets of $53 million). For the year ended December 31, 2024, petroleum revenue related to operations in the United States was $3.8 billion (year ended December 31, 2023 – $4.4 billion).

26. CAPITAL MANAGEMENT

The Corporation's capital consists of cash and cash equivalents, debt and shareholders' equity. The Corporation's objective for managing capital is to prioritize balance sheet strength while maintaining flexibility to repay debt, fund 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. Debt repayment, share repurchases, dividends and capital expenditures are anticipated to be funded by the Corporation's adjusted funds flow, cash-on-hand and/or other available liquidity.

On March 6, 2024, the TSX approved the renewal of the Corporation's NCIB. Pursuant to the NCIB, MEG will purchase for cancellation, from time to time, as it considers advisable, up to a maximum of 24,007,526 common shares of the Corporation. The NCIB became effective on March 11, 2024 and will terminate on March 10, 2025 or such earlier time as the NCIB is completed or terminated at the option of MEG.

The Corporation allocated free cash flow to both share repurchases and debt repayment from 2022 until its US$600 million net debt target was achieved in the third quarter of 2024. The Corporation then began returning 100% of free cash flow to shareholders through share repurchases and a quarterly base dividend. The Corporation's balance sheet strength and liquidity profile supports enhanced distributions to shareholders with a continued emphasis on share repurchases.

The following table summarizes the Corporation's net debt:

As at December 31	Note		2024		2023
Long-term debt	12	$	858	$	1,124
Cash and cash equivalents			(156)		(160)
Net debt - C$		$	702	$	964
Net debt - US$		$	488	$	730

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

During the year ended December 31, 2024, the Corporation redeemed the remaining US$258 million (approximately $351 million) of the Corporation's 7.125% senior unsecured notes due February 2027 at a weighted average price of 101.8% plus accrued and unpaid interest.

For the year ended December 31, 2024, the Corporation repurchased for cancellation 17.0 million common shares totaling $454 million.

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 and is considered quarterly.

Cash dividends of $0.10 per share were declared on July 25, 2024 and November 5, 2024 with payments on October 15, 2024 and January 15, 2025, respectively.

On February 27, 2025, the Corporation's Board of Directors declared a $0.10 per share dividend payable on April 15, 2025 to shareholders of record at the close of business on March 20, 2025.

The Corporation has $1.2 billion of available credit, comprised of $600 million under a revolving credit facility and $600 million under the 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 December 31, 2024, the Corporation had $600 million unutilized capacity under the revolving credit facility and, with $256 million of issued letters of credit, had $344 million of unutilized capacity under the $600 million EDC Facility.

The following table summarizes the Corporation's funds flow from operating activities, adjusted funds flow and free cash flow:

Year ended December 31	**2024**	**2023**
Funds flow from operating activities	**$ 1,385**	$ 1,476
Adjustments:		
Impact of cash-settled SBC units subject to equity price risk management	**—**	13
Realized equity price risk management gain	**—**	(87)
Adjusted funds flow	**1,385**	1,402
Capital expenditures	**(548)**	(449)
Free cash flow	**$ 837**	$ 953

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

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

27. COMMITMENTS AND CONTINGENCIES

a. Commitments

The Corporation's commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at December 31, 2024:

	2025	2026	2027	2028	2029	Thereafter	Total
Transportation and storage[(i)]	$ 504	$ 506	$ 507	$ 512	$ 497	$ 4,685	$ 7,211
Diluent purchases[(ii)(iii)]	266	72	65	66	65	32	566
Other operating commitments	20	19	10	9	6	58	122
Variable office lease costs	4	4	4	4	4	8	28
Capital commitments	74	—	—	—	—	—	74
Commitments	**$ 868**	**$ 601**	**$ 586**	**$ 591**	**$ 572**	**$ 4,783**	**$ 8,001**

(i) *This represents transportation and storage commitments from 2025 to 2048. Excludes amounts recognized on the consolidated balance sheet (Note 13).*

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

(iii) *During 2024, the Corporation executed a 5-year diluent supply commitment.*

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.

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