MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the 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.

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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

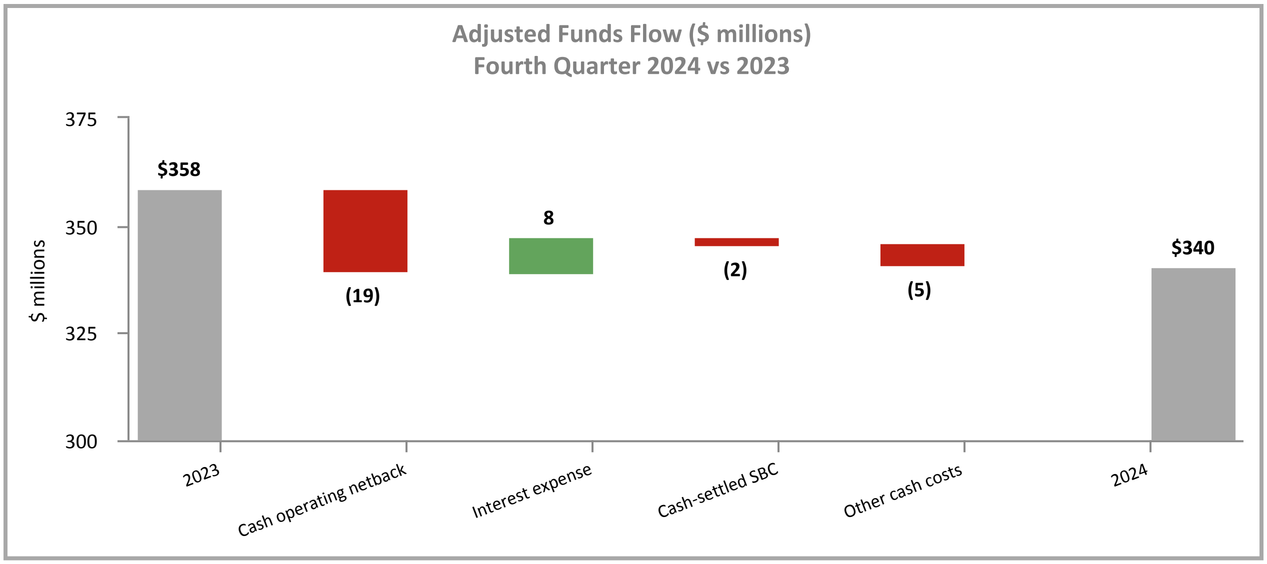
The Corporation generated funds flow from operating activities and adjusted funds flow of $340 million, or $1.29 per share, during the fourth quarter of 2024. After $172 million of capital expenditures, the Corporation's remaining $168 million of free cash flow, plus cash on hand, was used to return $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:

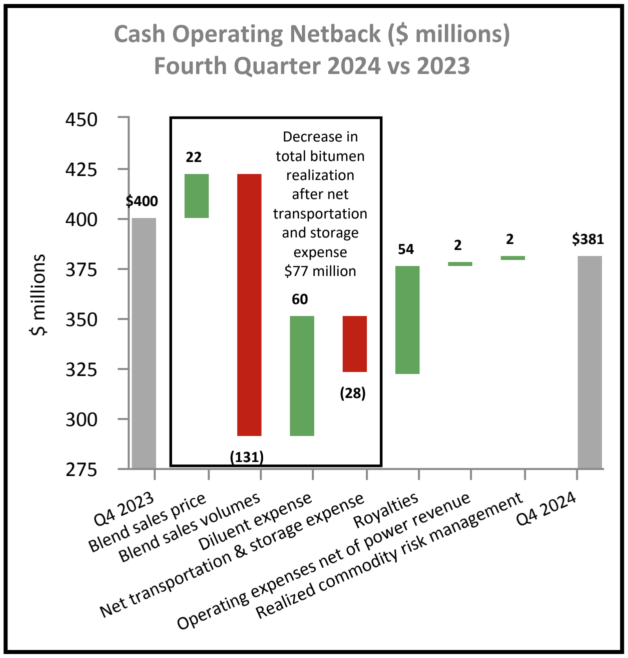
	Three months ended December 31	
($millions)	**2024**	**2023**
Funds flow from operating activities and Adjusted funds flow	**$ 340**	$ 358
Capital expenditures	**(172)**	(104)
Free cash flow	**$ 168**	$ 254
Adjusted funds flow per share - diluted	**$ 1.29**	$ 1.27

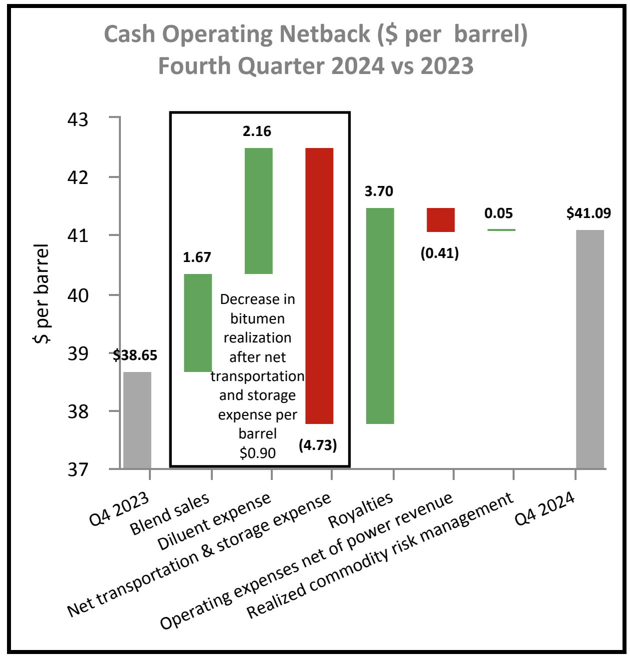


Funds flow from operating activities and adjusted funds flow decreased during the fourth quarter of 2024, compared to the same period of 2023, driven mainly by a lower cash operating netback partially offset by lower interest expense due to reduced debt levels. On a diluted per share basis, adjusted 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.*

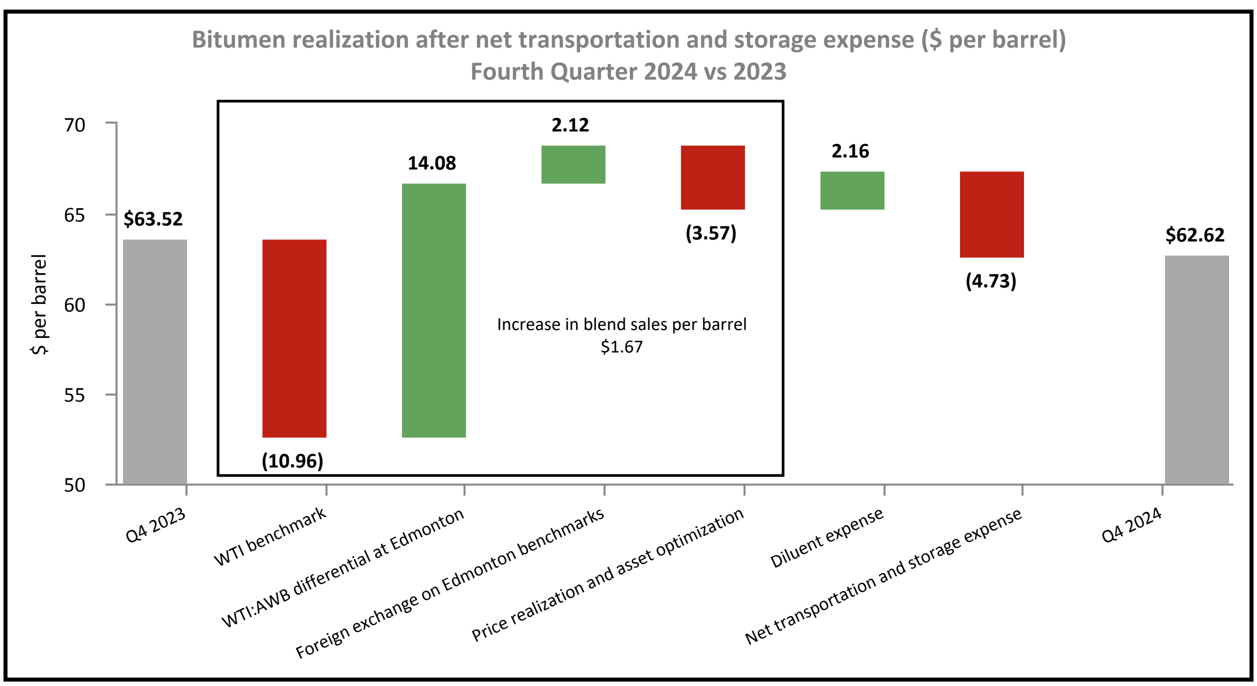




During the fourth quarter of 2024, total cash operating netback decreased 5% to $381 million compared to $400 million during the same period of 2023, mainly reflecting reduced sales volumes, partially offset by lower diluent expense and royalties.

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.

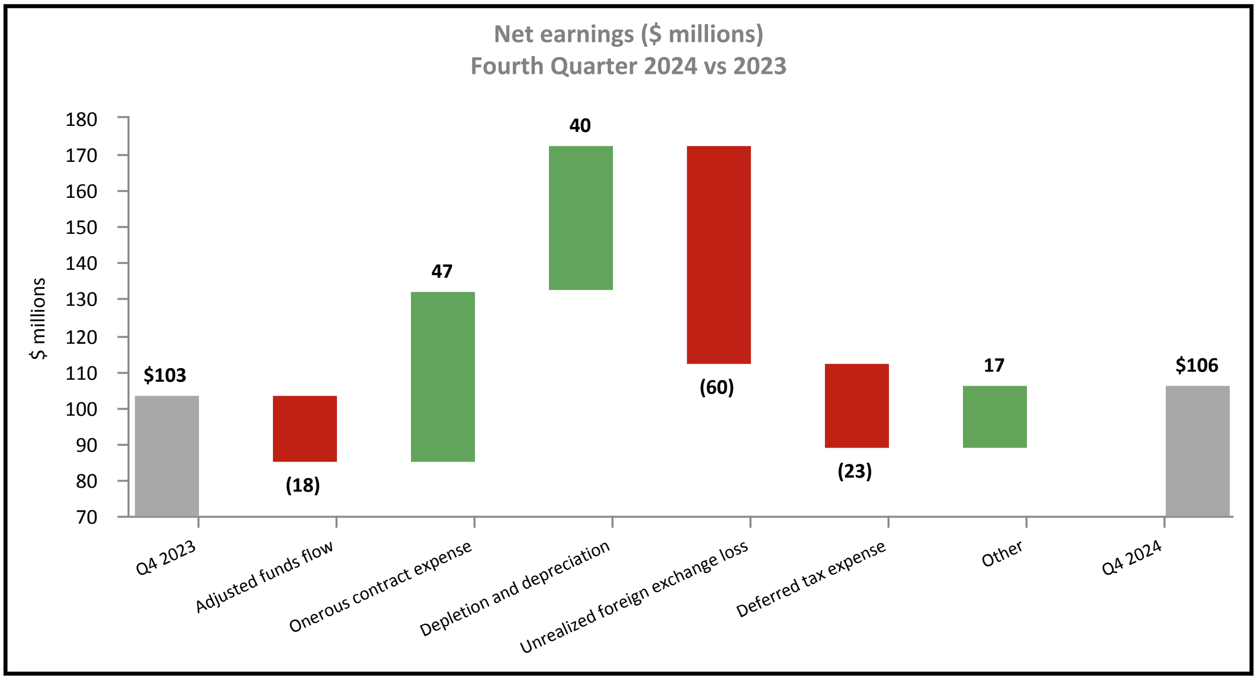
Lower fourth quarter 2024 royalties were driven by lower net revenues compared to the same period of 2023.



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.

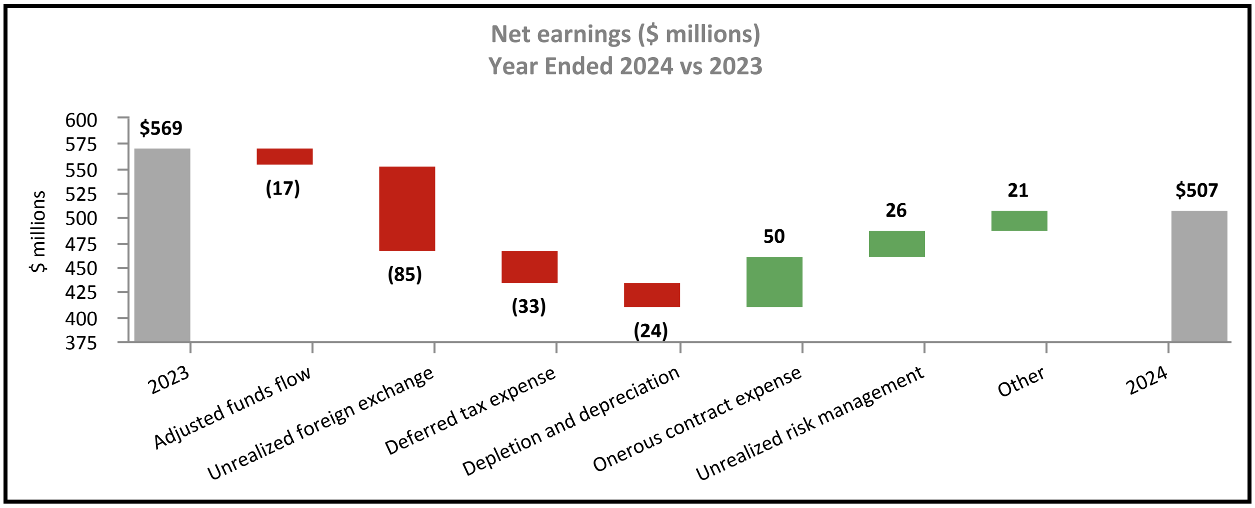
Decreased diluent expense, on a total and per barrel basis, reflects narrower WTI:AWB differentials partially offset by a higher average condensate price, relative to WTI. The decrease in total diluent expense also reflects lower diluent volumes required for blending. The Corporation recovered 83% of 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")

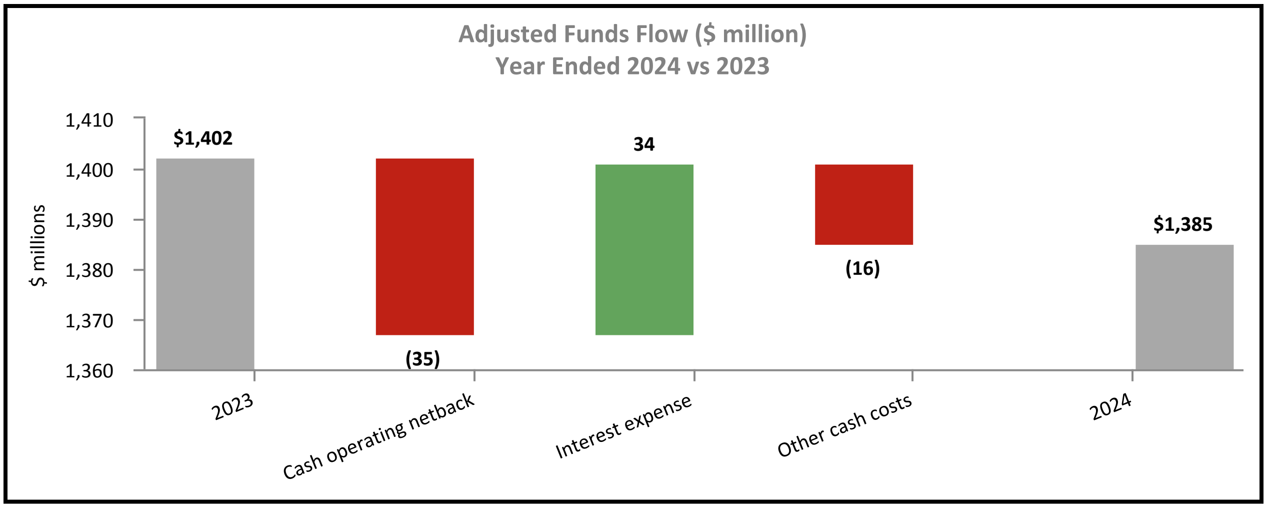
The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is SOR, which is an efficiency indicator that measures the amount of steam that 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



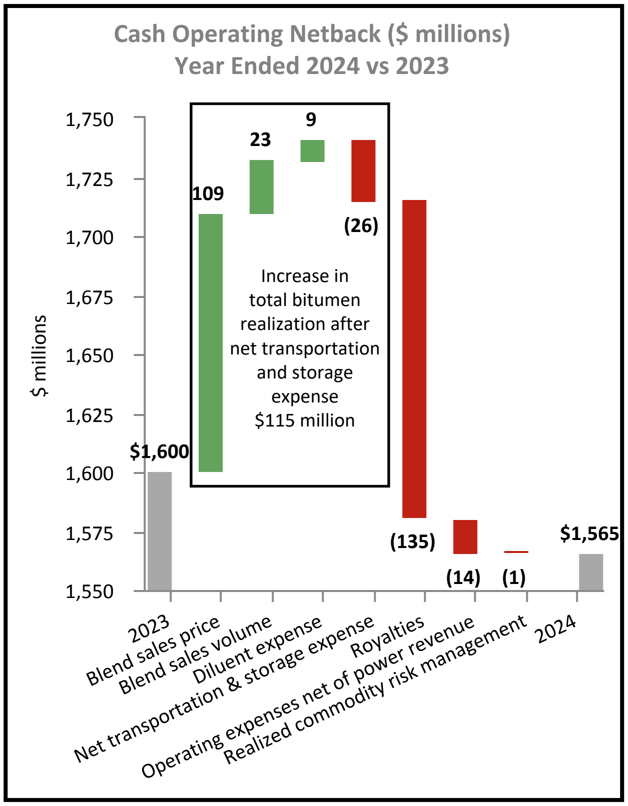
Funds flow from operating activities and adjusted funds flow decreased in 2024, compared to 2023, driven mainly by a lower cash operating netback partially offset by lower interest expense due to reduced debt levels. On a diluted per share basis, adjusted funds flow increased to $5.13 per share in 2024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

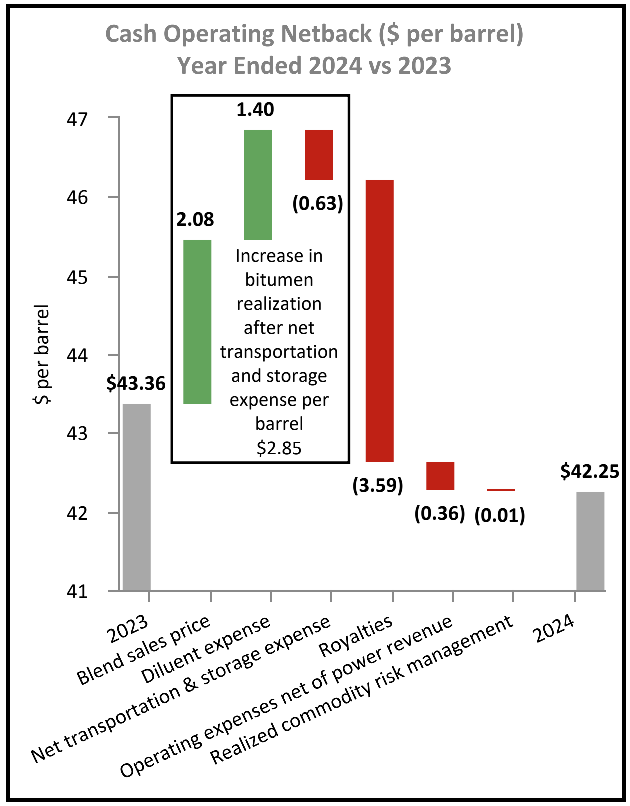
CASH OPERATING NETBACK

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	
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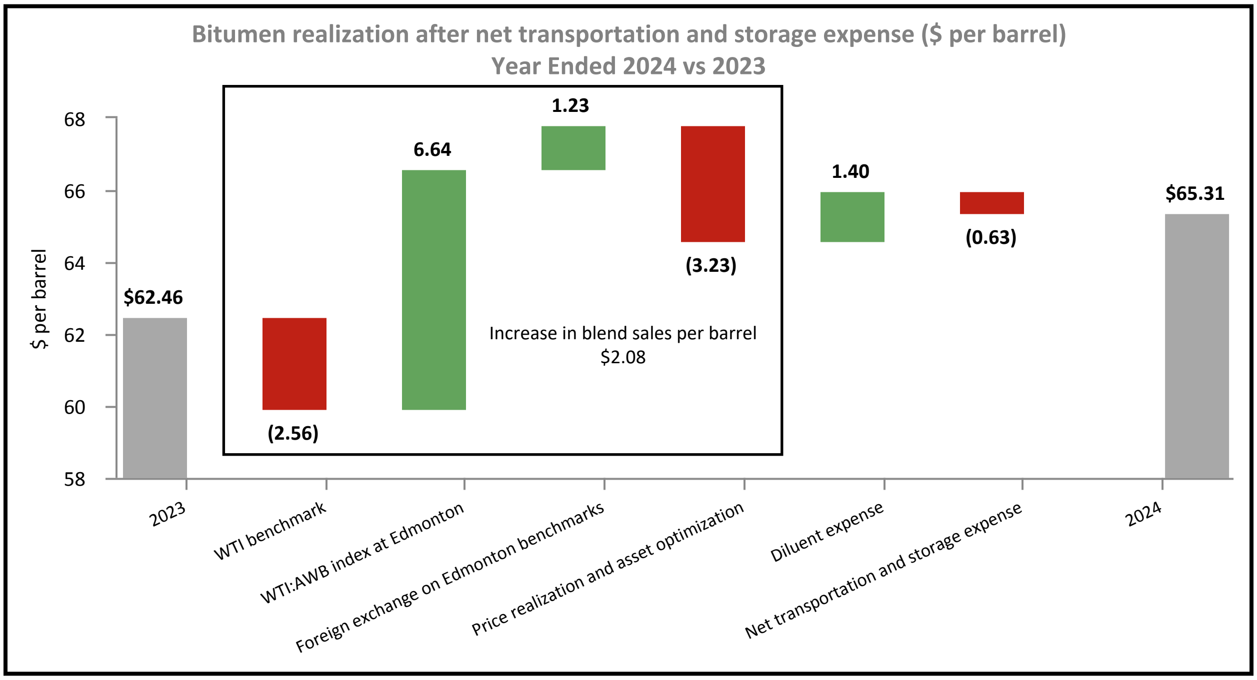
Bitumen realization after net transportation and storage expense	**$ 2,419**	**$ 65.31**	$ 2,304	$ 62.46
Bitumen sales volumes - bbls/d		**101,198**		101,086

(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.

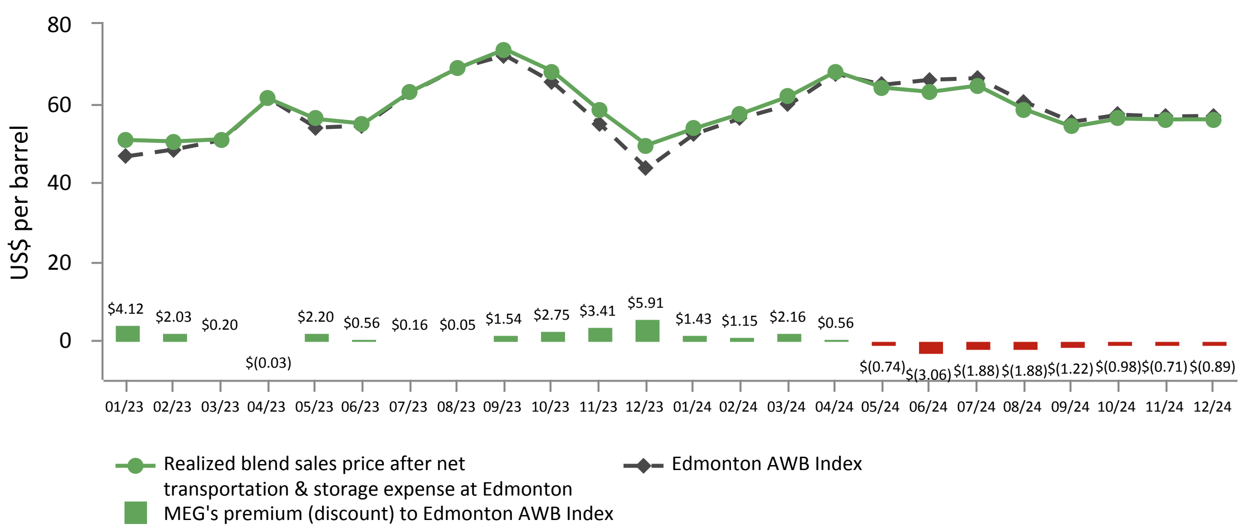
	2024		2023	
($millions, except as indicated)		$/bbl		$/bbl
Transportation and storage expense	**$ (625)**	**$ (16.86)**	$ (600)	$ (16.27)
Transportation revenue	**2**	**0.05**	3	0.09
Net transportation and storage expense	**$ (623)**	**$ (16.81)**	$ (597)	$ (16.18)
Bitumen sales volumes - bbls/d		**101,198**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

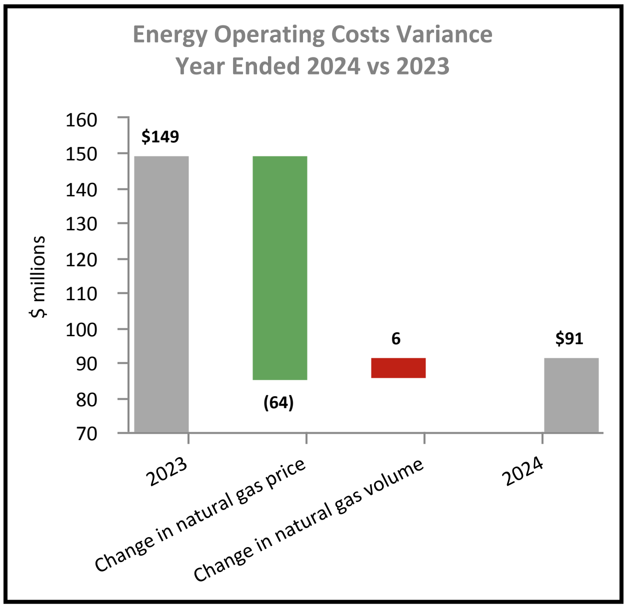
Operating Expenses net of Power Revenue

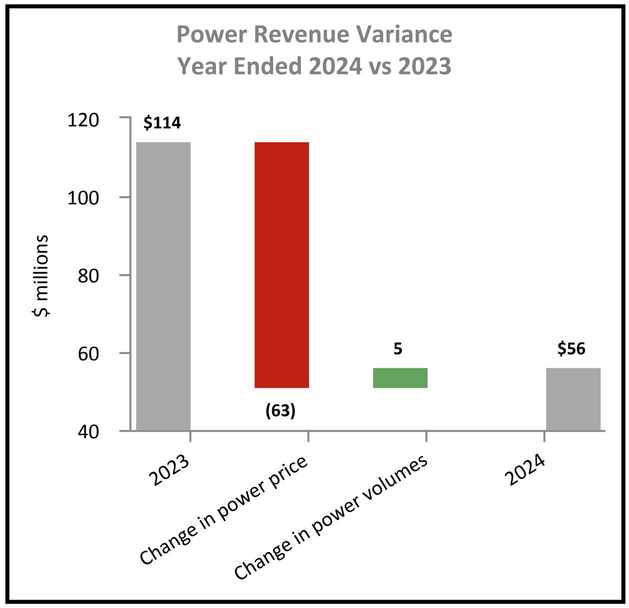
Operating expenses net of power revenue are comprised of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-oriented operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate 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.

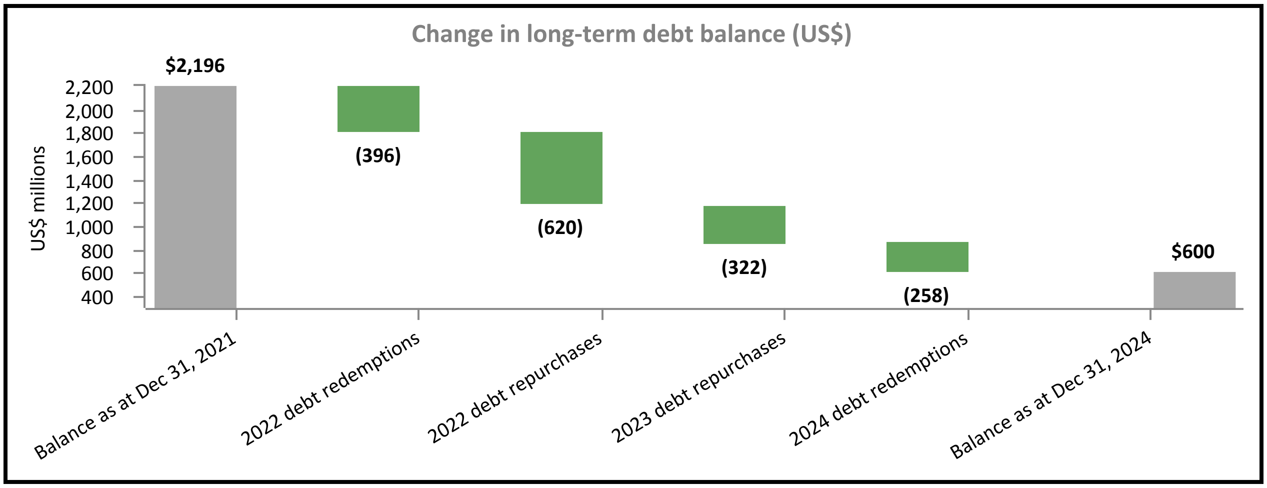
Lower December 31 total non-current liabilities in 2023 compared to 2022 primarily reflect US$322 million (approximately $437 million) of long-term debt repurchased during 2023. This was partially offset by increases in the decommissioning provision and deferred income tax liability as well as a 2023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

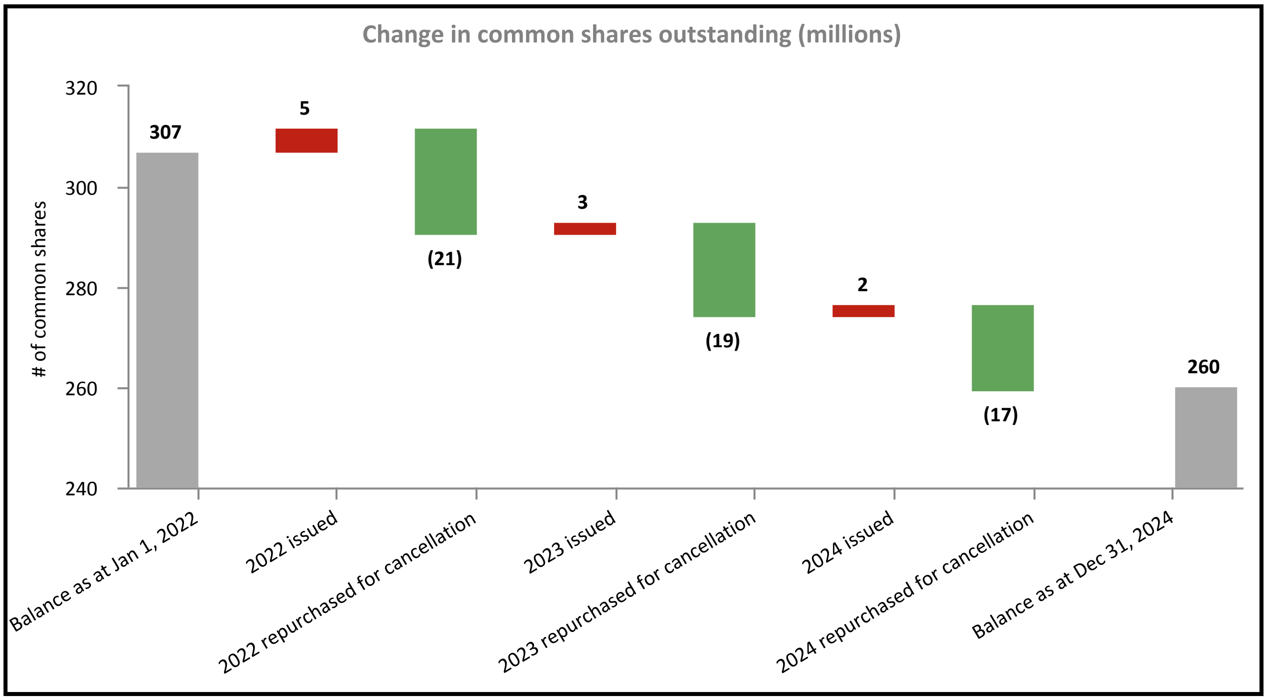
Cash dividends of $0.10 per share were declared on July 25, 2024 and November 5, 2024 with payments on October 15, 2024 and January 15, 2025, respectively.

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.