

Q3 2024

MANAGEMENT'S DISCUSSION AND ANALYSIS

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VERMILION
ENERGY



Disclaimer

Certain statements included or incorporated by reference in this document may constitute forward-looking statements or information under applicable securities legislation. Such forward-looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements or information in this document may include, but are not limited to: capital expenditures, including Vermilion's 2024 guidance, and Vermilion's ability to fund such expenditures; the flexibility of Vermilion's capital program and operations; business strategies and objectives; operational and financial performance; wells expected to be drilled and the timing thereof; exploration and development plans and the timing thereof; future drilling prospects; the ability of our asset base to deliver modest production growth; the evaluation of international acquisition opportunities; statements regarding the return of capital; our asset petroleum and natural gas sales; future production levels and the timing thereof, including Vermilion's 2024 guidance, and rates of average annual production growth; the effect of changes in crude oil and natural gas prices, changes in exchange and inflation rates; the payment and amount of future dividends; the effect of possible changes in critical accounting estimates; the Company's review of the impact of potential changes to financial reporting standards; the potential financial impact of climate-related risks; Vermilion's goals regarding its debt levels, including maintenance of a ratio of net debt to four quarter trailing funds flow from operations; statements regarding Vermilion's hedging program and the stability of our cash flows; operating and other expenses; royalty and income tax rates and Vermilion's expectations regarding future taxes and taxability; the timing of regulatory proceedings and approvals; and the release of our 2025 budget and the timing thereof.

Such forward-looking statements or information are based on a number of assumptions, all or any of which may prove to be incorrect. In addition to any other assumptions identified in this document, assumptions have been made regarding, among other things: the ability of Vermilion to obtain equipment, services and supplies in a timely manner to carry out its activities in Canada and internationally; the ability of Vermilion to market crude oil, natural gas liquids, and natural gas successfully to current and new customers; the timing and costs of pipeline and storage facility construction and expansion and the ability to secure adequate product transportation; the timely receipt of required regulatory approvals; the ability of Vermilion to obtain financing on acceptable terms; foreign currency exchange rates and interest rates; future crude oil, natural gas liquids, and natural gas prices; management's expectations relating to the timing and results of exploration and development activities; the impact of Vermilion's dividend policy on its future cash flows; credit ratings; hedging program; expected earnings/(loss) and adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows and free cash flow and expected future cash flow and free cash flow per share; estimated future dividends; financial strength and flexibility; debt and equity market conditions; general economic and competitive conditions; ability of management to execute key priorities; and the effectiveness of various actions resulting from the Vermilion's strategic priorities.

Although Vermilion believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Vermilion can give no assurance that such expectations will prove to be correct. Financial outlooks are provided for the purpose of understanding Vermilion's financial position and business objectives, and the information may not be appropriate for other purposes. Forward-looking statements or information are based on current expectations, estimates, and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Vermilion and described in the forward-looking statements or information. These risks and uncertainties include, but are not limited to: the ability of management to execute its business plan; the risks of the oil and gas industry, both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil, natural gas liquids, and natural gas; risks and uncertainties involving geology of crude oil, natural gas liquids, and natural gas deposits; risks inherent in Vermilion's marketing operations, including credit risk; the uncertainty of reserves estimates and reserves life and estimates of resources and associated expenditures; the uncertainty of estimates and projections relating to production and associated expenditures; potential delays or changes in plans with respect to exploration or development projects; Vermilion's ability to enter into or renew leases on acceptable terms; fluctuations in crude oil, natural gas liquids, and natural gas prices, foreign currency exchange rates, interest rates and inflation; health, safety, and environmental risks; uncertainties as to the availability and cost of financing; the ability of Vermilion to add production and reserves through exploration and development activities; the possibility that government policies or laws may change or governmental approvals may be delayed or withheld; uncertainty in amounts and timing of royalty payments; risks associated with existing and potential future law suits and regulatory actions against or involving Vermilion; and other risks and uncertainties described elsewhere in this document or in Vermilion's other filings with Canadian securities regulatory authorities.

This document contains references to sustainability/ESG data and performance that reflect metrics and concepts that are commonly used in such frameworks as the Global Reporting Initiative, the Task Force on Climate-related Financial Disclosures, and the Sustainability Accounting Standards Board. Vermilion has used best efforts to align with the most commonly accepted methodologies for ESG reporting, including with respect to climate data and information on potential future risks and opportunities, in order to provide a fuller context for our current and future operations. However, these methodologies are not yet standardized, are frequently based on calculation factors that change over time, and continue to evolve rapidly. Readers are particularly cautioned to evaluate the underlying definitions and measures used by other companies, as these may not be comparable to Vermilion's. While Vermilion will continue to monitor and adapt its reporting accordingly, the Company is not under any duty to update or revise the related sustainability/ESG data or statements except as required by applicable securities laws.

The forward-looking statements or information contained in this document are made as of the date hereof and Vermilion undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events, or otherwise, unless required by applicable securities laws.

This document discloses certain oil and gas metrics, including DCET costs, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this MD&A to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the Company's performance in previous periods and therefore such metrics should not be unduly relied upon. DCET costs includes all capital spent to drill, complete, equip and tie-in a well. Additional oil and gas metrics in this document may include, but are not limited to:

Boe Equivalency: Per barrel of oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6:1). Barrel of oil equivalents (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, as the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Estimates of Drilling Locations: Unbooked drilling locations are the internal estimates of Vermilion based on Vermilion's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by Vermilion's management as an estimation of Vermilion's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that Vermilion will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and natural gas reserves, resources or production. The drilling locations on which Vermilion will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been de-risked by Vermilion drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management of Vermilion has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Initial Production Rates and Short-Term Test Rates: This document discloses test rates of production for certain wells over short periods of time (i.e. 24 hours, IP30, IP60, IP90, etc.), which are preliminary and not determinative of the rates at which those or any other wells will commence production and thereafter decline. Short-term test rates are not necessarily indicative of long-term well or reservoir performance or of ultimate recovery. Although such rates are useful in confirming the presence of hydrocarbons, they are preliminary in nature, are subject to a high degree of predictive uncertainty as a result of limited data availability and may not be representative of stabilized on-stream production rates. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Production over a longer period will also experience natural decline rates, which can be high in certain plays in which the Company operates, and may not be consistent over the longer term with the decline experienced over an initial production period. Initial production or test rates may also include recovered "load" fluids used in well completion stimulation operations. Actual results will differ from those realized during an initial production period or short-term test period, and the difference may be material.

Financial data contained within this document are reported in Canadian dollars, unless otherwise stated.

Abbreviations

\$M	thousand dollars
\$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
GJ	gigajoules
LSB	light sour blend crude oil reference price
mbbls	thousand barrels
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point
NCIB	normal-course issuer bid
NGLs	natural gas liquids, which includes butane, propane, and ethane
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
tCO ₂ e	tonnes of carbon dioxide equivalent
THE	the price for natural gas in Germany, quoted in megawatt hours of natural gas, at the Trading Hub Europe
TTF	the price for natural gas in the Netherlands, quoted in megawatt hours of natural gas, at the Title Transfer Facility Virtual Trading Point
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated November 6, 2024, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three and nine months ended September 30, 2024 compared with the corresponding period in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three and nine months ended September 30, 2024 and the audited consolidated financial statements for the years ended December 31, 2023 and 2022, together with the accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR+ at www.sedarplus.ca or on Vermilion's website at www.vermilionenergy.com.

The unaudited condensed consolidated interim financial statements for the three and nine months ended September 30, 2024 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with IAS 34, "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB").

This MD&A includes references to certain financial measures which are not specified, defined, or determined under IFRS and are therefore considered non-GAAP and other specified financial measures. These financial measures are unlikely to be comparable to similar financial measures presented by other issuers. For a full description of these non-GAAP and other specified financial measures and a reconciliation of these measures to their most directly comparable GAAP measures, please refer to "Non-GAAP and Other Specified Financial Measures".

Product Type Disclosure

Under National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities", disclosure of production volumes should include segmentation by product type as defined in the instrument. In this report, references to "crude oil" and "light and medium crude oil" mean "light crude oil and medium crude oil" and references to "natural gas" mean "conventional natural gas".

In addition, in Supplemental Table 4 "Production", Vermilion provides a reconciliation from total production volumes to product type and also a reconciliation of "crude oil and condensate" and "NGLs" to the product types "light crude oil and medium crude oil" and "natural gas liquids".

Production volumes reported are based on quantities as measured at the first point of sale.

Guidance

On December 12, 2023, we released our 2024 capital budget and associated production guidance, which assumed a mid-year startup of the new BC Montney battery and Croatia gas plant. On May 1, 2024, we increased 2024 guidance for royalty rate and cash taxes to reflect the impact of higher forward pricing for crude oil on these items. On July 31, 2024, we increased 2024 production guidance to reflect consistently strong operational performance across our asset base over the first half of 2024. On November 6, 2024, we tightened our 2024 production guidance range to reflect increased certainty on annual production levels. The Company's guidance for 2024 is as follows:

Category	Prior ⁽¹⁾	Current ⁽¹⁾
Production (boe/d)	83,000 - 86,000	84,000 - 85,000
E&D capital expenditures (\$MM)	\$600 - 625	\$600 - 625
Royalty rate (% of sales)	9 - 11%	9 - 11%
Operating (\$/boe)	\$17.00 - 18.00	\$17.00 - 18.00
Transportation (\$/boe)	\$3.00 - 3.50	\$3.00 - 3.50
General and administration (\$/boe)	\$2.50 - 3.00	\$2.50 - 3.00
Cash taxes (% of pre-tax FFO)	7 - 9%	7 - 9%
Asset retirement obligations settled (\$MM)	\$60	\$60
Payments on lease obligations (\$MM) ⁽²⁾	\$30 - 60	\$30 - 60

⁽¹⁾ Current 2024 guidance reflects foreign exchange assumptions of CAD/USD 1.37, CAD/EUR 1.49, and CAD/AUD 0.91. Prior 2024 guidance reflects foreign exchange assumptions of CAD/USD 1.36, CAD/EUR 1.48, and CAD/AUD 0.91.

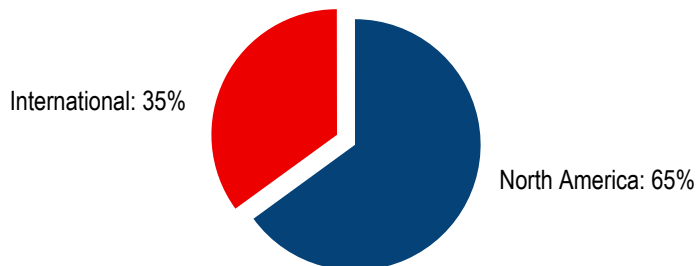
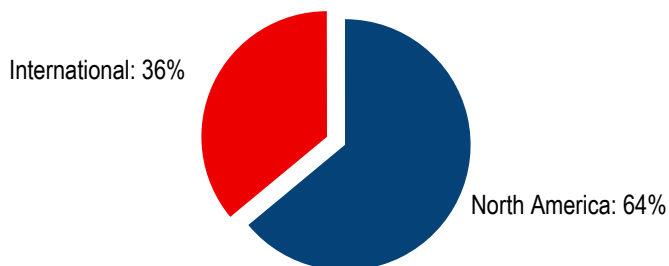
⁽²⁾ Payments on lease obligations includes contractual amounts owing on leases, as well as up to \$30 million to account for accelerated principal payments that may be made in 2024.

Vermilion's Business

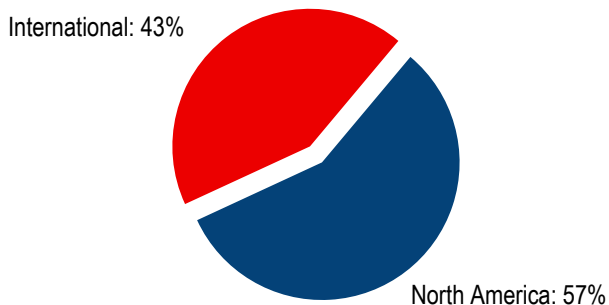
Vermilion is a Calgary, Alberta-based international oil and gas producer focused on the acquisition, exploration, development, and optimization of producing properties in North America, Europe, and Australia. We manage our business through our Calgary head office and our international business unit offices.

YTD 2024 production of 84,881 boe/d

YTD 2024 capital expenditures of \$422.3MM



YTD 2024 fund flows from operations of \$943.1MM



Consolidated Results Overview

	Q3 2024	Q3 2023	Q3/24 vs. Q3/23	YTD 2024	YTD 2023	2024 vs. 2023
Production ⁽¹⁾						
Crude oil and condensate (bbls/d)	29,837	31,417	(5)%	31,797	31,407	1%
NGLs (bbls/d)	7,547	7,344	3%	7,264	7,261	—%
Natural gas (mmcf/d)	280.73	263.80	6%	274.93	265.09	4%
Total (boe/d)	84,173	82,727	2%	84,881	82,849	3%
(Draw) build in inventory (mbbls)	(164)	52		(324)	73	
Financial metrics						
Fund flows from operations (\$M) ⁽²⁾	275,024	270,218	2%	943,085	770,494	22%
Per share (\$/basic share)	1.76	1.65	7%	5.93	4.70	26%
Net earnings (loss) (\$M)	51,697	57,309	(10)%	(28,423)	565,549	N/A
Per share (\$/basic share)	0.33	0.35	(6)%	(0.18)	3.45	N/A
Cash flows from operating activities (\$M)	134,547	118,436	14%	755,164	680,697	11%
Free cash flow (\$M) ⁽³⁾	153,755	144,579	6%	520,764	323,190	61%
Long-term debt (\$M)	903,354	966,505	(7)%	903,354	966,505	(7)%
Net debt (\$M) ⁽⁴⁾	833,331	1,242,522	(33)%	833,331	1,242,522	(33)%
Activity						
Capital expenditures (\$M) ⁽⁵⁾	121,269	125,639	(4)%	422,321	447,304	(6)%
Acquisitions (\$M) ⁽⁶⁾	1,642	5,238	(69)%	16,844	247,294	(93)%
Dispositions (\$M)	—	—		—	182,152	

⁽¹⁾ Please refer to Supplemental Table 4 "Production" for disclosure by product type.

⁽²⁾ Fund flows from operations (FFO) and FFO per share are a total of segments measure and supplementary financial measure most directly comparable to net earnings (loss) and net earnings (loss) per share, respectively. The measures do not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other issuers. FFO is comprised of sales less royalties, transportation, operating, G&A, corporate income tax, PRRT, windfall taxes, interest expense, equity based compensation settled in cash, realized gain (loss) on derivatives, plus realized gain (loss) on foreign exchange and realized other income (expense). The measure is used to assess the contribution of each business unit to Vermilion's ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments. A reconciliation to the primary financial statement measures can be found within the "Non-GAAP and Other Specified Financial Measures" section of this MD&A.

⁽³⁾ Free cash flow (FCF) is a non-GAAP financial measure most directly comparable to cash flows from operating activities; it does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other issuers. FCF is comprised of fund flows from operations less drilling and development costs and exploration and evaluation costs. The measure is used to determine the funding available for investing and financing activities including payment of dividends, repayment of long-term debt, reallocation into existing business units and deployment into new ventures. A reconciliation to primary financial statement measures can be found within the "Non-GAAP and Other Specified Financial Measures" section of this MD&A.

⁽⁴⁾ Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements" and is most directly comparable to long-term debt. Net debt is comprised of long-term debt (excluding unrealized foreign exchange on swapped USD borrowings) plus adjusted working capital (defined as current assets less current liabilities, excluding current derivatives and current lease liabilities), and represents Vermilion's net financing obligations after adjusting for the timing of working capital fluctuations. Net debt excludes lease obligations which are secured by a corresponding right-of-use asset. A reconciliation to the primary financial statement measures can be found within the "Financial Position Review" section of this MD&A.

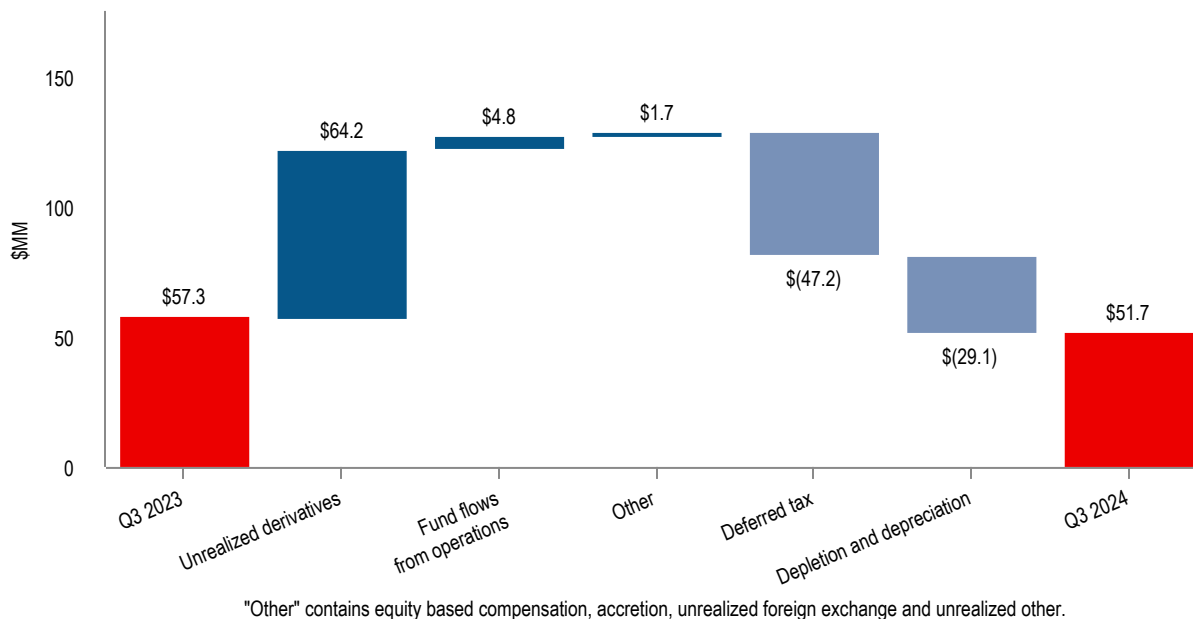
⁽⁵⁾ Capital expenditures is a non-GAAP financial measure that does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other issuers. The measure is calculated as the sum of drilling and development costs and exploration and evaluation costs from the Consolidated Statements of Cash Flows. We consider capital expenditures to be a useful measure of our investment in our existing asset base. Capital expenditures are also referred to as E&D capital. A reconciliation to the primary financial statement measures can be found within the "Non-GAAP and Other Specified Financial Measures" section of this MD&A.

⁽⁶⁾ Acquisitions is a non-GAAP financial measure that does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other issuers. The measure is calculated as the sum of acquisitions, net of cash and acquisitions of securities from the Consolidated Statements of Cash Flows, Vermilion common shares issued as consideration, the estimated value of contingent consideration, the amount of acquiree's outstanding long-term debt assumed, and net acquired working capital deficit or surplus. We believe that including these components provides a useful measure of the economic investment associated with our acquisition activity. A reconciliation to the acquisitions line item in the Consolidated Statements of Cash Flows can be found in "Supplemental Table 3: Capital Expenditures and Acquisitions" section of this MD&A.

Financial performance review

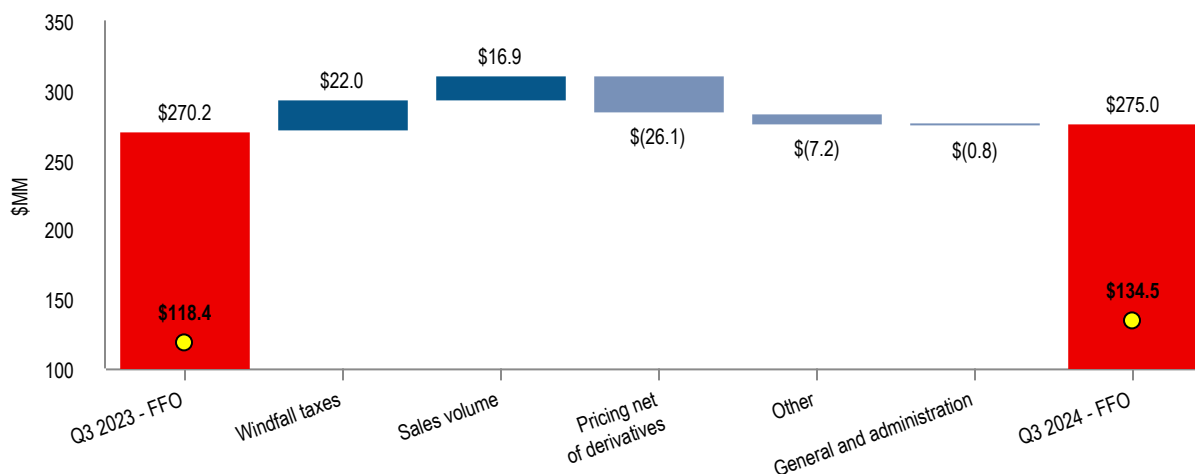
Q3 2024 vs. Q3 2023

Net earnings of \$51.7MM in Q3 2024 compared to \$57.3MM in Q3 2023



- We recorded net earnings of \$51.7 million (\$0.33/basic share) for Q3 2024 compared to net earnings of \$57.3 million (\$0.35/basic share) in Q3 2023. The decrease in net earnings was primarily due to increases in deferred tax and depletion and depreciation, partially offset by decreases in unrealized derivative losses of \$64.2 million due to changes in our mark-to-market position.

Increased FFO driven by absence of windfall taxes and increased sales volumes, partially offset by lower pricing. Increased cash flows from operating activities driven by working capital timing.

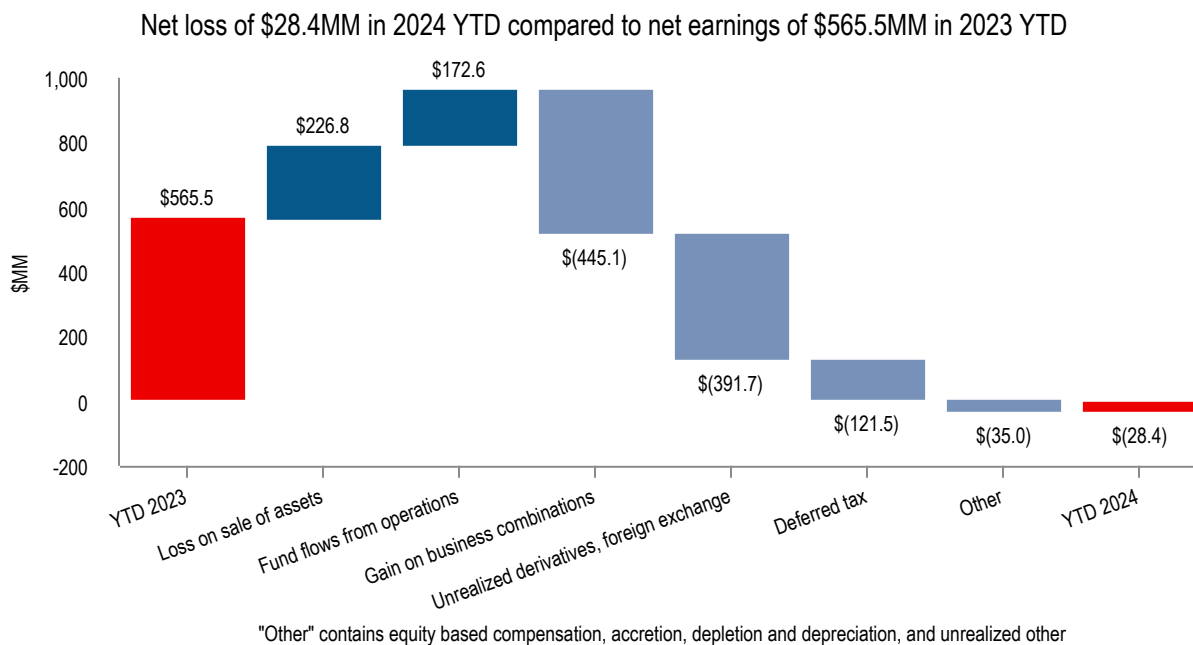


"Pricing net of derivatives" contains pricing variance on sales volumes (WTI, AECO, Dated Brent & TTF and NBP) and realized derivatives.
 "Sales volume" is the sum of sales volume variance in all regions. "Other" contains royalties, transportation, operating expense, interest, taxes, realized foreign exchange, and other realized income.

● Cash flows from operating activities

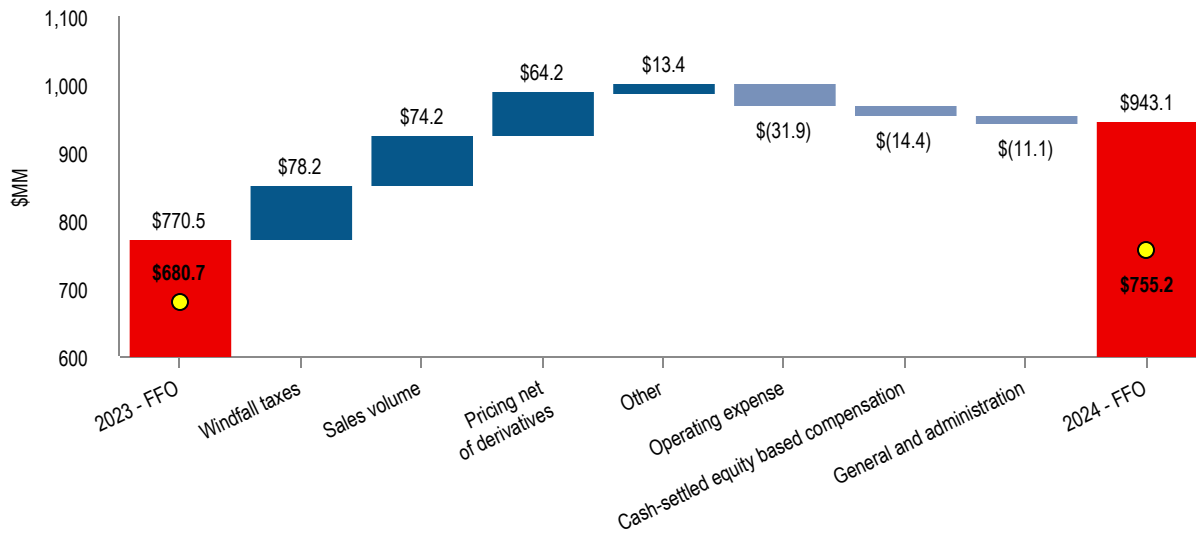
- We generated cash flows from operating activities of \$134.5 million in Q3 2024 compared to \$118.4 million in Q3 2023 and fund flows from operations of \$275.0 million in Q3 2024 compared to \$270.2 million in Q3 2023. The increase in fund flows from operations was primarily driven by the absence of windfall taxes and increased sales volumes in Australia, Ireland and Croatia, partially offset by lower realized gains on Euro gas derivative contracts. The variance between cash flows from operating activities and fund flows from operations is primarily due to working capital timing related to payments made on windfall taxes payable.

2024 vs. 2023



- For the nine months ended September 30, 2024, we recorded a net loss of \$28.4 million compared to net earnings of \$565.5 million for the comparable period in 2023. The decrease in net earnings (loss) was primarily attributable to the net gain recognized on acquisition and disposition activity in 2023 and changes in our mark-to-market position, partially offset by higher FFO driven by higher realized gains on commodity contracts.

Cash flows from operating activities and funds flow from operations increased on absence of windfall taxes, impacts of 2023 A&D activity, and Australia liftings



"Pricing net of derivatives" contains pricing variance on sales volumes (WTI, AECO, Dated Brent & TTF and NBP) and realized derivatives.

"Sales volume" is the sum of sales volume variance in all regions. "Other" contains, interest, corporate income taxes, royalties, transportation, realized foreign exchange and other realized income.

● Cash flows from operating activities

- For the nine months ended September 30, 2024 as compared to 2023, cash flows from operating activities increased by \$74.5 million to \$755.2 million and fund flows from operations increased by \$172.6 million to \$943.1 million. The increase in fund flows from operations was primarily driven by the absence of windfall taxes, organic growth and acquisitions and increased sales volumes in Australia, Ireland and Croatia, and realized gains on derivative contracts. This was partially offset by cash-settled equity compensation in 2024, and other costs and taxes. Variances between cash flows from operating activities and funds flow from operations are primarily driven by working capital timing differences related to payments made on windfall taxes payable.

Production review

Q3 2024 vs. Q3 2023

- Consolidated average production of 84,173 boe/d in Q3 2024 increased compared to Q3 2023 production of 82,727 boe/d. Production increased primarily due to production starting on the SA-10 block in Croatia, timing of annual turnarounds in Ireland, and production in Australia after downtime in 2023, partially offset by lower production in North America as Montney growth was more than offset by natural declines in Alberta, Saskatchewan and Wyoming and some Canadian gas production shut-in due to weak AECO pricing.

2024 vs. 2023

- Consolidated average production of 84,881 boe/d in the nine months ended September 30, 2024 increased compared to the prior year comparative period production of 82,849 boe/d. Production increased primarily due to unplanned downtime in Australia in 2023 and increased production in Ireland due to the acquisition of an additional 36.5% interest in the Corrib Natural Gas Project at the end of Q1 2023. This was partially offset by disposition activities in 2023.

Activity review

For the three months ended September 30, 2024, capital expenditures were \$121.3 million.

- In our North America core region we invested capital expenditures of \$78.2 million, primarily comprised of \$76.8 million of capital expenditure in Canada:
 - At Mica, we completed and brought on production five (5.0 net) BC Montney liquids-rich shale gas wells;
 - In the Deep Basin, we drilled three (2.3 net), completed three (2.3 net), and brought on production one (1.0 net) Mannville liquids-rich conventional natural gas wells;
 - In Saskatchewan, we drilled, completed, and brought on production five (5.0 net) light and medium crude oil wells;
 - In the United States, we invested \$1.4 million as five (0.2 net) non-operated light and medium crude oil wells were brought on production.
- In our International core region, capital expenditures of \$43.1 million were invested during Q3 2024:
 - In Germany, we invested \$15.5 million as we began drilling our second deep gas exploration well and made progress on tie-in operations of our successful first deep gas exploration well, which is planned to come on production first half 2025;
 - In France, we invested \$11.4 million primarily on subsurface maintenance, workover, and facilities activities;
 - In Australia, \$8.7 million was invested as we performed routine facilities maintenance;
 - In the Netherlands, we invested \$5.2 million, primarily on facilities and tie-in activities;
 - In Central and Eastern Europe, \$2.0 million was invested as we successfully increased production of the SA-10 block and completed testing on the third well of our four-well program on the SA-7 block;
 - In Ireland, \$0.3 million was invested on facilities.

Financial sustainability review

Free cash flow

- Free cash flow of \$520.8 million increased by \$197.6 million for the nine months ended September 30, 2024 compared to the prior year period primarily driven by increased fund flows from operations primarily driven by non-recurring windfall taxes incurred in 2023, increased sales volumes, higher pricing net of derivatives, and timing of capital expenditures.

Long-term debt and net debt

- Long-term debt decreased to \$903.4 million as at September 30, 2024 (December 31, 2023 - \$914.0 million) due to repurchases made on the 2025 senior notes partially offset by the strengthening of the US dollar. The revolving credit facility remained undrawn.
- As at September 30, 2024, net debt decreased to \$833.3 million (December 31, 2023 - \$1,078.6 million) as a result of strong free cash flow generation.
- The ratio of net debt to four quarter trailing fund flows from operations⁽¹⁾ decreased to 0.6 as at September 30, 2024 (December 31, 2023 - 0.9) primarily due to lower net debt and higher four quarter trailing fund flows from operations on settlement of derivative contracts and lower windfall taxes.

⁽¹⁾ Net debt to four quarter trailing fund flows from operations is a supplementary financial measure that does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other issuers. It is calculated as net debt (capital measure) over the FFO from the preceding four quarters (total of segments measure). The measure is used to assess our ability to repay debt.

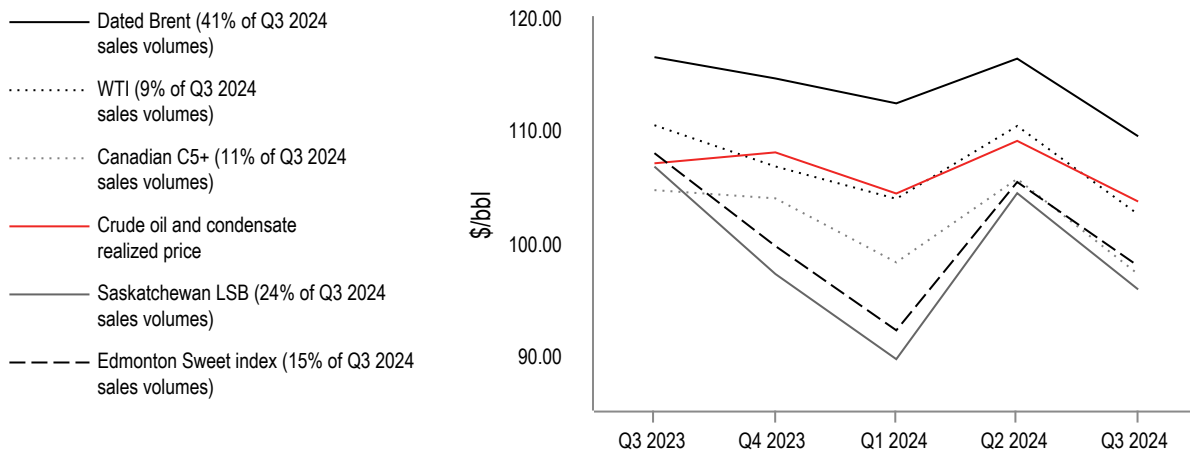
Benchmark Commodity Prices

	Q3 2024	Q3 2023	Q3/24 vs. Q3/23	YTD 2024	YTD 2023	2024 vs. 2023
Crude oil						
WTI (\$/bbl)	102.41	110.33	(7)%	105.49	104.15	1%
WTI (US \$/bbl)	75.10	82.26	(9)%	77.54	77.40	—%
Edmonton Sweet index (\$/bbl)	97.83	107.84	(9)%	98.40	100.62	(2)%
Edmonton Sweet index (US \$/bbl)	71.74	80.41	(11)%	72.33	74.77	(3)%
Saskatchewan LSB index (\$/bbl)	95.75	106.65	(10)%	96.51	98.25	(2)%
Saskatchewan LSB index (US \$/bbl)	70.21	79.52	(12)%	70.94	73.02	(3)%
Canadian C5+ Condensate index (\$/bbl)	97.10	104.56	(7)%	100.28	103.23	(3)%
Canadian C5+ Condensate index (US \$/bbl)	71.20	77.96	(9)%	73.71	76.72	(4)%
Dated Brent (\$/bbl)	109.34	116.35	(6)%	112.63	110.53	2%
Dated Brent (US \$/bbl)	80.18	86.76	(8)%	82.79	82.14	1%
Natural gas						
North America						
AECO 5A (\$/mcf)	0.69	2.61	(74)%	1.45	2.76	(47)%
AECO 7A (\$/mcf)	0.81	2.38	(66)%	1.43	3.03	(53)%
Henry Hub (\$/mcf)	2.94	3.42	(14)%	2.85	3.62	(21)%
Henry Hub (US \$/mcf)	2.16	2.55	(15)%	2.10	2.69	(22)%
Europe⁽¹⁾						
NBP Day Ahead (\$/mmbtu)	14.51	13.88	5%	13.14	16.61	(21)%
NBP Month Ahead (\$/mmbtu)	14.78	13.54	9%	13.41	20.36	(34)%
NBP Day Ahead (€/mmbtu)	9.68	9.51	2%	8.89	11.40	(22)%
NBP Month Ahead (€/mmbtu)	9.86	9.28	6%	9.07	13.97	(35)%
TTF Day Ahead (\$/mmbtu)	15.52	14.11	10%	13.62	17.39	(22)%
TTF Month Ahead (\$/mmbtu)	15.42	13.74	12%	13.70	21.19	(35)%
TTF Day Ahead (€/mmbtu)	10.35	9.67	7%	9.21	11.93	(23)%
TTF Month Ahead (€/mmbtu)	10.29	9.42	9%	9.26	14.54	(36)%
Average exchange rates						
CDN \$/US \$	1.36	1.34	1%	1.36	1.35	1%
CDN \$/Euro	1.50	1.46	3%	1.48	1.46	1%
Realized prices						
Crude oil and condensate (\$/bbl)	103.55	106.94	(3)%	105.54	100.64	5%
NGLs (\$/bbl)	27.49	27.77	(1)%	30.99	30.89	—%
Natural gas (\$/mcf)	6.57	6.32	4%	6.13	8.08	(24)%
Total (\$/boe)	61.97	62.92	(2)%	62.63	66.57	(6)%

⁽¹⁾ NBP and TTF pricing can occur on a day-ahead ("DA") or month-ahead ("MA") basis. DA prices in a period reflect the average current day settled price on the next days' delivery and MA prices in a period represent daily one month futures contract prices which are determined at the end of each month. In a rising price environment, the DA price will tend to be greater than the MA price and vice versa. Natural gas in the Netherlands and Germany is benchmarked to the TTF and production is generally equally split between DA and MA contracts. Natural gas in Ireland is benchmarked to the NBP and is sold on DA contracts.

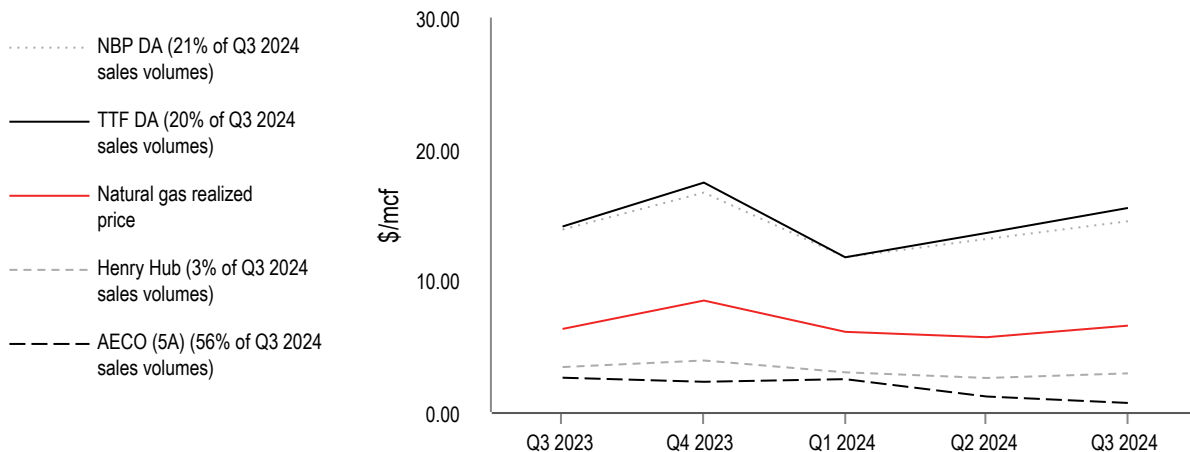
As an internationally diversified producer, we are exposed to a range of commodity prices. In our North America core region, our crude oil is sold at benchmarks linked to WTI (including the Edmonton Sweet index, the Saskatchewan LSB index, and the Canadian C5+ index) and our natural gas is sold at benchmarks linked to the AECO index (in Canada) or the Henry Hub ("HH") index (in the United States). In our International core region, our crude oil is sold with reference to Dated Brent and our natural gas is sold with reference to NBP, TTF, or indices highly correlated to TTF.

Q3 2024 realized crude oil and condensate price was a \$5.72/bbl premium to Edmonton Sweet Index



- Crude oil prices decreased in Q3 2024 relative to Q3 2023 on weaker supply-demand fundamentals and macroeconomic uncertainty. Canadian dollar WTI decreased by 7% and Brent decreased by 6% in Q3 2024 relative to Q3 2023.
- In Canadian dollar terms, year-over-year, the Edmonton Sweet differential widened by \$2.09/bbl to a discount of \$4.58/bbl against WTI, and the Saskatchewan LSB differential widened by \$2.98/bbl to a discount of \$6.66/bbl against WTI.
- Approximately 41% of Vermilion's Q3 2024 crude oil and condensate production was priced at the Dated Brent index, which averaged a premium to WTI of US\$5.08/bbl, while the remainder of our crude oil and condensate production was priced at the Saskatchewan LSB, Canadian C5+, Edmonton Sweet, and WTI indices.

Q3 2024 realized natural gas price was a \$5.88/mcf premium to AECO 5A



- In Canadian dollar terms, year-over-year, prices for European natural gas at NBP and TTF increased by 5% and 10% respectively on a day-ahead basis. On a month ahead basis, NBP and TTF increased by 9% and 12% respectively. Prices increased in response to greater competition in the global LNG market and the risk of losing Russian gas flows transiting Ukraine.
- Year-over-year natural gas prices in Canadian dollar terms at NYMEX HH decreased by 15%, and AECO 7A decreased by 66%. AECO prices declined due to strong production growth and historically high storage levels, whereas NYMEX HH performed relatively better due to stronger US natural gas demand and moderate supply growth.
- For Q3 2024, average European natural gas prices represented an \$14.37/mcf premium to AECO. Approximately 41% of our natural gas production in Q3 2024 benefited from this premium European pricing.

North America

	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Production⁽¹⁾				
Crude oil and condensate (bbls/d)	19,045	20,883	19,483	21,619
NGLs (bbls/d)	7,547	7,344	7,264	7,261
Natural gas (mmcf/d)	164.07	171.19	163.31	168.42
Total production volume (boe/d)	53,936	56,758	53,961	56,951

⁽¹⁾ Please refer to Supplemental Table 4 "Production" for disclosure by product type.

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Sales	201,804	40.67	257,248	49.26	647,110	43.77	775,580	49.88
Royalties	(30,492)	(6.14)	(40,489)	(7.75)	(99,025)	(6.70)	(108,812)	(7.00)
Transportation	(15,474)	(3.12)	(10,878)	(2.08)	(40,931)	(2.77)	(31,763)	(2.04)
Operating	(58,937)	(11.88)	(63,138)	(12.09)	(197,095)	(13.33)	(199,473)	(12.83)
General and administration ⁽¹⁾	(5,432)	(1.09)	(3,748)	(0.72)	(26,323)	(1.78)	(8,605)	(0.55)
Corporate income tax expense ⁽¹⁾	(1,676)	(0.34)	(35)	(0.01)	(729)	(0.05)	(1,184)	(0.08)
Fund flows from operations	89,793	18.10	138,960	26.61	283,007	19.14	425,743	27.38
Drilling and development	(78,171)		(69,703)		(276,200)		(321,496)	
Free cash flow	11,622		69,257		6,807		104,247	

⁽¹⁾ General and administration includes amounts from our Corporate segment. Corporate income tax expense primarily relates to income taxes on Corporate segment activities.

Production from our North American operations averaged 53,936 boe/d in Q3 2024, a decrease of 2% from Q2 2024 due to declines in our Deep Basin and United States assets and some Canadian gas production shut-in due to weak AECO pricing, partially offset by new production from our recent BC Mica Montney wells.

At Mica, we completed and brought on production five (5.0 net) BC Montney liquids-rich shale gas wells. In the Deep Basin, we drilled three (2.3 net), completed three (2.3 net), and brought on production one (1.0 net) Mannville liquids-rich conventional natural gas wells. In Saskatchewan, we drilled, completed, and brought on production five (5.0 net) light and medium crude oil wells, while in the United States, five (0.2 net) non-operated light and medium crude oil wells were brought on production.

Sales

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	170,780	38.06	209,403	45.52	535,460	40.51	661,289	47.36
United States	31,024	65.30	47,845	77.03	111,650	71.23	114,291	72.07
North America	201,804	40.67	257,248	49.26	647,110	43.77	775,580	49.88

Sales in North America decreased for the three and nine months ended September 30, 2024 compared to the prior year primarily due to lower realized pricing combined with lower production volumes following the sale of non-core southeast Saskatchewan assets and sale of Wyoming assets in 2023.

Royalties

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	(22,214)	(4.95)	(26,856)	(5.84)	(66,935)	(5.06)	(77,752)	(5.57)
United States	(8,278)	(17.42)	(13,633)	(21.95)	(32,090)	(20.47)	(31,060)	(19.59)
North America	(30,492)	(6.14)	(40,489)	(7.75)	(99,025)	(6.70)	(108,812)	(7.00)
Royalty rate (% of sales)	15.1 %		15.7 %		15.3 %		14.0 %	

Royalties in North America decreased on a dollar and per unit basis for the three months ended September 30, 2024 compared to the prior year primarily due to lower realized pricing. Royalties decreased on a dollar basis and per unit basis for the nine months ended September 30, 2024 compared to the prior year primarily due to reduced pricing and partially offset by new wells drilled in Mica and the United States with higher royalty rates.

Transportation

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	(15,079)	(3.36)	(10,709)	(2.33)	(39,606)	(3.00)	(31,462)	(2.25)
United States	(395)	(0.83)	(169)	(0.27)	(1,325)	(0.85)	(301)	(0.19)
North America	(15,474)	(3.12)	(10,878)	(2.08)	(40,931)	(2.77)	(31,763)	(2.04)

Transportation expense in North America increased on a dollar and per boe basis for the three and nine months ended September 30, 2024 compared to the prior year comparable periods primarily due to increased trucking expenses related to new activity on our Mica assets and higher pipeline fees.

Operating expense

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	(52,837)	(11.78)	(59,191)	(12.87)	(176,435)	(13.35)	(182,288)	(13.06)
United States	(6,100)	(12.84)	(3,947)	(6.35)	(20,660)	(13.18)	(17,185)	(10.84)
North America	(58,937)	(11.88)	(63,138)	(12.09)	(197,095)	(13.33)	(199,473)	(12.83)

Operating expense in North America decreased on a dollar and per boe basis for the three months ended September 30, 2024 compared to the prior year comparable period primarily due to timing of maintenance activities. For the nine months ended September 30, 2024, operating expense increased on a per boe basis primarily due to gas processing fees in the Mica region, and decreased on a dollar basis on lower production due to the disposition of properties in southeast Saskatchewan and Wyoming in 2023.

International

	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Production⁽¹⁾				
Crude oil and condensate (bbls/d)	10,792	10,534	12,314	9,787
Natural gas (mmcf/d)	116.66	92.61	111.62	96.67
Total production volume (boe/d)	30,237	25,969	30,920	25,899
Total sales volume (boe/d)	32,024	25,386	32,106	25,565

⁽¹⁾ Please refer to Supplemental Table 4 "Production" for disclosure by product type.

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Sales	288,291	97.85	218,284	93.46	829,945	94.34	724,006	103.74
Royalties	(12,246)	(4.16)	8,280	3.55	(38,876)	(4.42)	(37,734)	(5.41)
Transportation	(11,219)	(3.81)	(10,582)	(4.53)	(34,041)	(3.87)	(34,652)	(4.96)
Operating	(79,869)	(27.11)	(59,732)	(25.58)	(231,252)	(26.29)	(196,971)	(28.22)
General and administration	(16,371)	(5.56)	(17,211)	(7.37)	(45,720)	(5.20)	(52,301)	(7.49)
Corporate income tax expense	(11,031)	(3.74)	(31,333)	(13.42)	(49,716)	(5.65)	(71,374)	(10.23)
PRRT	(507)	(0.17)	—	—	(14,928)	(1.70)	—	—
Fund flows from operations	157,048	53.30	107,706	46.11	415,412	47.21	330,974	47.43
Drilling and development	(40,638)		(49,701)		(134,257)		(115,306)	
Exploration and evaluation	(2,460)		(6,235)		(11,864)		(10,502)	
Free cash flow	113,950		51,770		269,291		205,166	

Production from our International operations averaged 30,237 boe/d in Q3 2024, an increase of 1% from Q2 2024 primarily due to new production from our SA-10 block in Croatia and higher runtime in Germany and Ireland, partially offset by planned maintenance downtime in Australia.

In Germany, we successfully completed testing operations for our first deep gas exploration well drilled earlier this year. The well flow tested at a restricted rate of 17 mmcf/d of natural gas with a wellhead pressure of 4,625 psi, which supports our expectation that deliverability would have been higher without testing equipment limitations. Tie-in operations are progressing to bring the well on production in the first half of 2025.

In Croatia, we successfully increased production on the SA-10 block after commissioning the gas plant in late June 2024. Production in Q3 2024 averaged 1,855 boe/d (100% European natural gas) and currently exceeds 2,000 boe/d. On the SA-7 block, we completed testing on the third well of our four-well program, which flow tested at 5.6 mmcf/d of natural gas.

In Australia, planned maintenance at our Wandoo facility was executed during Q3 2024. Production resumed late in the quarter and continues to perform well.

Sales

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Australia	47,661	128.84	—	—	155,274	130.39	—	—
France	67,888	108.26	88,970	115.36	240,540	111.43	233,154	107.18
Netherlands	34,204	88.18	27,856	74.00	99,711	77.59	135,193	109.30
Germany	43,063	88.79	37,606	83.24	103,404	80.74	151,331	106.29
Ireland	79,333	87.60	63,798	86.76	213,590	79.23	201,974	94.92
Central and Eastern Europe	16,142	94.59	54	73.37	17,426	93.67	2,354	156.78
International	288,291	97.85	218,284	93.46	829,945	94.34	724,006	103.74

As a result of changes in inventory levels, our sales volumes for crude oil in Australia, France, and Germany may differ from our production volumes in those business units. The following table provides the crude oil sales volumes (consisting entirely of "light crude oil and medium crude oil") for those jurisdictions.

Crude oil sales volumes (bbls/d)	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
Australia	4,021		—		4,346		—	
France	6,816		8,383		7,878		7,968	
Germany	1,704		1,528		1,191		1,429	
International	12,541		9,911		13,415		9,397	

Sales increased on a dollar basis for the three months ended September 30, 2024 compared to the prior year primarily due to production in Australia coming back online after downtime in 2023 and production starting on the SA-10 block in Croatia. On a per boe basis, sales increased due to the impact of realized prices on our Australian and Croatian production partially offset by lower realized commodity prices.

Sales increased on a dollar basis for the nine months ended September 30, 2024 compared to the prior year primarily due to production starting on the SA-10 block in Croatia, downtime in Australia in 2023, incremental volumes related to the Corrib acquisition in Ireland, and timing of transportation in France. On a per boe basis, sales decreased due to lower realized gas prices, partially offset by the impact of realized prices on our Australian production.

Royalties

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
France	(8,538)	(13.62)	(12,351)	(16.01)	(31,873)	(14.77)	(30,275)	(13.92)
Netherlands	—	—	20,607	54.75	(217)	(0.17)	(875)	(0.71)
Germany	(1,348)	(2.78)	142	0.32	(4,138)	(3.23)	(5,257)	(3.69)
Central and Eastern Europe	(2,360)	(13.83)	(118)	(160.33)	(2,648)	(14.23)	(1,327)	(88.38)
International	(12,246)	(4.16)	8,280	3.55	(38,876)	(4.42)	(37,734)	(5.41)
Royalty rate (% of sales)	4.2 %		(3.8)%		4.7 %		5.2 %	

Royalties in our International core region are primarily incurred in France, Germany, the Netherlands and Croatia, where royalties, depending on jurisdiction, include charges based on a percentage of sales and fixed per boe charges. Our production in Australia and Ireland is not subject to royalties.

Royalties increased on a dollar and per unit basis for the three months ended September 30, 2024 compared to the three months ended September 30, 2023 primarily due to adjustments for prior period royalties in Netherlands and Germany recorded in 2023. Royalties decreased on a per unit basis for the nine months ended September 30, 2024 primarily due to higher production volumes in Croatia, which is subject to lower royalties.

Transportation

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
France	(5,712)	(9.11)	(4,351)	(5.64)	(17,476)	(8.10)	(18,766)	(8.63)
Germany	(3,210)	(6.62)	(3,674)	(8.13)	(8,788)	(6.86)	(9,847)	(6.92)
Ireland	(2,297)	(2.54)	(2,557)	(3.48)	(7,777)	(2.88)	(6,039)	(2.84)
International	(11,219)	(3.81)	(10,582)	(4.53)	(34,041)	(3.87)	(34,652)	(4.96)

Transportation expense decreased on a per boe basis for the three and nine months ended September 30, 2024 compared to the prior year primarily due to prior period tariff adjustments in Germany recorded in 2023 and the impact of vessel cost and sales volume timing in France.

Our production in Australia, Netherlands and Central and Eastern Europe is not subject to transportation expense.

Operating expense

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Australia	(28,521)	(77.10)	(9,937)	—	(69,481)	(58.35)	(41,683)	—
France	(14,733)	(23.49)	(21,810)	(28.28)	(50,779)	(23.52)	(63,113)	(29.01)
Netherlands	(7,887)	(20.33)	(3,411)	(9.06)	(29,206)	(22.73)	(30,014)	(24.26)
Germany	(14,394)	(29.68)	(14,008)	(31.01)	(39,585)	(30.91)	(35,624)	(25.02)
Ireland	(13,632)	(15.05)	(10,372)	(14.10)	(40,689)	(15.09)	(25,516)	(11.99)
Central and Eastern Europe	(702)	(4.11)	(194)	(263.59)	(1,512)	(8.13)	(1,021)	(68.00)
International	(79,869)	(27.11)	(59,732)	(25.58)	(231,252)	(26.29)	(196,971)	(28.22)

Operating expenses increased on a dollar and per boe basis for the three months ended September 30, 2024 primarily due to the resumption of production in Australia and associated liftings, partially offset by decreased fuel and electricity costs in France in the current year combined with higher sales volumes in the prior year.

For the nine months ended September 30, 2024, operating expenses increased on a dollar basis primarily due to the resumption of production in Australia and associated liftings, combined with an increased working interest acquired in Ireland at Q1 2023, and higher facility maintenance and turnaround costs for planned downtime in Q2 2024. This increase was partially offset by decreased power costs in France in the current year combined with higher sales volumes in the prior year.

Operating expenses decreased on a per boe basis for the nine months ended September 30, 2024 compared to the prior year primarily attributable to lower power costs in France and Netherlands, partially offset by planned downtime in Germany and Ireland resulting in lower volumes.

Consolidated Financial Performance Review

Financial performance

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Sales	490,095	61.97	475,532	62.92	1,477,055	62.63	1,499,586	66.57
Royalties	(42,738)	(5.40)	(32,209)	(4.26)	(137,901)	(5.85)	(146,546)	(6.51)
Transportation	(26,693)	(3.38)	(21,460)	(2.84)	(74,972)	(3.18)	(66,415)	(2.95)
Operating	(138,806)	(17.55)	(122,870)	(16.26)	(428,347)	(18.16)	(396,444)	(17.60)
General and administration	(21,803)	(2.76)	(20,959)	(2.77)	(72,043)	(3.05)	(60,906)	(2.70)
Corporate income tax expense	(12,707)	(1.61)	(31,368)	(4.15)	(50,445)	(2.14)	(72,558)	(3.22)
Windfall taxes	—	—	(21,953)	(2.90)	—	—	(78,177)	(3.47)
PRRT	(507)	(0.06)	—	—	(14,928)	(0.63)	—	—
Interest expense	(21,187)	(2.68)	(20,218)	(2.68)	(60,641)	(2.57)	(62,303)	(2.77)
Equity based compensation	—	—	—	—	(14,361)	(0.61)	—	—
Realized gain on derivatives	49,891	6.31	73,625	9.74	316,523	13.42	155,628	6.91
Realized foreign exchange gain	1,155	0.15	2,089	0.28	5,293	0.22	997	0.04
Realized other (expense) income	(1,676)	(0.21)	(9,991)	(1.32)	(2,148)	(0.09)	(2,368)	(0.11)
Fund flows from operations	275,024	34.78	270,218	35.76	943,085	39.99	770,494	34.19
Equity based compensation	(6,412)	—	(6,362)	—	(8,070)	—	(34,885)	—
Unrealized (loss) gain on derivative instruments ⁽¹⁾	(1,052)	—	(65,294)	—	(315,585)	—	38,581	—
Unrealized foreign exchange gain (loss) ⁽¹⁾	(11,382)	—	(12,042)	—	(29,954)	—	7,604	—
Accretion	(19,126)	—	(20,068)	—	(55,269)	—	(58,718)	—
Depletion and depreciation	(180,164)	—	(151,087)	—	(519,782)	—	(453,607)	—
Deferred tax (expense) recovery	(4,713)	—	42,489	—	(42,025)	—	79,435	—
Gain on business combination	—	—	—	—	—	—	445,094	—
Loss on disposition	—	—	—	—	—	—	(226,828)	—
Unrealized other expense ⁽¹⁾	(478)	—	(545)	—	(823)	—	(1,621)	—
Net earnings (loss)	51,697	—	57,309	—	(28,423)	—	565,549	—

⁽¹⁾ Unrealized (loss) gain on derivative instruments, Unrealized foreign exchange (loss) gain, and Unrealized other expense are line items from the respective Consolidated Statements of Cash Flows.

Fluctuations in fund flows from operations may occur as a result of changes in production levels, commodity prices, and costs to produce petroleum and natural gas. In addition, fund flows from operations may be affected by the timing of crude oil shipments in Australia and France. When crude oil inventory is built up, the related operating expense, royalties, and depletion expense are deferred and carried as inventory on the consolidated balance sheet. When the crude oil inventory is subsequently drawn down, the related expenses are recognized within profit or loss.

General and administration

- General and administration expense remained relatively flat for the three months ended September 30, 2024 compared to the prior year.
- General and administration expense increased for the nine months ended September 30, 2024 compared to the prior year primarily due to accounting for the cash settlement of previously issued equity based settled compensation (previously accounted for as a share-based settled expense) and headcount costs.

Equity based compensation

- Equity based compensation included within funds flow from operations for the three and nine months ended September 30, 2024 is a result of settling withholding taxes via cash which were previously settled through the issuance and sale of shares from treasury.

PRRT and corporate income taxes

- PRRT for the three and nine months ended September 30, 2024 increased compared to the prior year due to downtime in Australia that resulted in no taxable income for the nine months ended September 30, 2023.
- Corporate income taxes for the three and nine months ended September 30, 2024 decreased compared to the same periods in the prior year due to combined lower taxable income mainly as a result of decreased commodity prices.

Windfall taxes

- Windfall taxes are the temporary taxes levied pursuant to the European Union's temporary solidarity contribution. The contribution set out minimum amounts to be calculated on taxable profits starting in 2022 and/or 2023, which are above a 20% increase of the average yearly taxable profits for 2018 to 2021. For the two-year period of the European Union's temporary solidarity contribution, Vermilion incurred \$301 million of incremental taxes. Windfall taxes are not applicable to 2024 and future periods.

Interest expense

- Interest expense for the three months ended September 30, 2024 increased compared to the same period in the prior year primarily due to interest incurred on the processing facility lease in Canada, partially offset by interest income earned on our cash position and reduced debt on the 2025 senior notes due to buybacks. Interest expense for the nine months ended September 30, 2024 decreased compared to the same period 2023 due to the credit facility remaining undrawn throughout the period, reduced debt on the senior notes due to buybacks and higher interest income earned on our cash position, partially offset by interest incurred on the processing facility lease.

Realized gain or loss on derivatives

- For the three and nine months ended September 30, 2024, we recorded realized gains on our natural gas and crude oil hedges due to lower commodity pricing compared to the strike prices.
- A listing of derivative positions as at September 30, 2024 is included in "Supplemental Table 2" of this MD&A.

Realized other income or expense

- Realized other income for the three and nine months ended September 30, 2024 decreased compared to the same periods in the prior year primarily due to decreased amounts for funding under the Saskatchewan Accelerated Site Closure program and proceeds received from insurance claims in 2023.

Net earnings (loss)

Fluctuations in net earnings (loss) from period-to-period are caused by changes in both cash and non-cash based income and charges. Cash based items are reflected in fund flows from operations. Non-cash items include: equity based compensation expense, unrealized gains and losses on derivative instruments, unrealized foreign exchange gains and losses, accretion, depletion and depreciation expense, and deferred taxes. In addition, non-cash items may also include gains or losses resulting from acquisition or disposition activity or charges resulting from impairment or impairment reversals.

Equity based compensation

Equity based compensation expense relates primarily to non-cash compensation expense attributable to long-term incentives granted to directors, officers, and employees under security-based arrangements. Equity based compensation expense for the three months ended September 30, 2024 remained relatively flat compared to the same period in the prior year. Equity based compensation expense for the nine months ended September 30, 2024 decreased compared to the same period in the prior year primarily due to the cash settlement of previously share-based settled expenses and the lower value of LTIP awards settled in the current year.

Unrealized gain or loss on derivative instruments

Unrealized gain or loss on derivative instruments arises as a result of changes in forecasts for future prices and rates. As Vermilion uses derivative instruments to manage the commodity price exposure of our future crude oil and natural gas production, we will normally recognize unrealized gains on derivative instruments when future commodity price forecasts decline and vice-versa. As derivative instruments are settled, the unrealized gain or loss previously recognized is reversed, and the settlement results in a realized gain or loss on derivative instruments.

For the three months ended September 30, 2024, we recognized a net unrealized loss on derivative instruments of \$1.1 million. This consists of unrealized losses of \$21.9 million on our European natural gas commodity derivative instruments and \$7.0 million on our equity swaps, partially offset by unrealized gains of \$22.4 million on our crude oil commodity derivative instruments, \$4.5 million on our North American gas commodity derivative instruments and \$0.9 million on our USD-to-CAD foreign exchange swaps.

For the nine months ended September 30, 2024, we recognized a net unrealized loss on derivative instruments of \$315.6 million. This consists of unrealized losses of \$294.4 million on our European natural gas commodity derivative instruments, \$10.3 million on our equity swaps, \$9.7 million on our crude oil commodity derivative instruments and \$3.6 million on our USD-to-CAD foreign exchange swaps, partially offset by a \$2.4 million gain on our North American gas commodity derivative instruments.

Unrealized foreign exchange gains or losses

As a result of Vermilion's international operations, Vermilion has monetary assets and liabilities denominated in currencies other than the Canadian dollar. These monetary assets and liabilities include cash, receivables, payables, long-term debt, derivative instruments and intercompany loans. Unrealized foreign exchange gains and losses result from translating these monetary assets and liabilities from their underlying currency to the Canadian dollar.

In 2024, unrealized foreign exchange gains and losses primarily resulted from:

- The translation of Euro and US dollar denominated intercompany loans from our international subsidiaries to Vermilion Energy Inc. An appreciation in the Euro and/or the US dollar against the Canadian dollar will result in an unrealized foreign exchange loss (and vice-versa). Under IFRS, the offsetting foreign exchange loss or gain is recorded as a currency translation adjustment within other comprehensive income. As a result, consolidated comprehensive income reflects the offsetting of these translation adjustments while net earnings (loss) reflects only the parent company's side of the translation.
- The translation of our USD denominated 2025 senior unsecured notes and USD denominated 2030 senior unsecured notes.

For the three months ended September 30, 2024, we recognized a net unrealized foreign exchange loss of \$11.4 million, primarily driven by the effects of the Euro strengthening 2.8% on our Euro denominated loans and the US dollar weakening 1.4% on our US dollar denominated loans. This loss was partially offset by the US dollar weakening 1.4% against the Canadian dollar on our USD senior notes. For the nine months ended September 30, 2024, we recognized an unrealized foreign exchange loss of \$30.0 million, primarily driven by the effects of the US dollar strengthening 2.1% against the Canadian dollar on our USD senior notes combined with losses on our Euro denominated intercompany loans, partially offset by gains on our USD denominated intercompany loans.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. For the three months ended September 30, 2024, compared to the three months ended September 30, 2023, accretion remained relatively flat. For the nine months ended September 30, 2024, accretion expense decreased versus the prior year primarily due to lower North American asset retirement balance related to dispositions completed in 2023 and changes in discount rates, partially offset by the Corrib acquisition completed in 2023.

Depletion and depreciation

Depletion and depreciation expense is recognized to allocate the cost of capital assets over the useful life of the respective assets. Depletion and depreciation expense per unit of production is determined for each depletion unit (which are groups of assets within a specific production area that have similar economic lives) by dividing the sum of the net book value of capital assets and future development costs by total proved plus probable reserves.

Fluctuations in depletion and depreciation expense are primarily the result of changes in produced crude oil and natural gas volumes, and changes in depletion and depreciation per unit. Fluctuations in depletion and depreciation per unit are the result of changes in reserves, depletable base (net book value of capital assets and future development costs), and relative production mix.

Depletion and depreciation on a per boe basis for the three and nine months ended September 30, 2024 of \$22.78 and \$22.04 increased from \$19.99 and \$20.14 in the same periods of the prior year, respectively, primarily due to higher future development costs increasing the depletable base, decreased reserve estimates, and the weakening of the Canadian dollar on European assets. The increase was partially offset by decreases to the depletable base from the impairments and dispositions recorded in 2023.

Deferred tax

Deferred tax assets arise when the tax basis of an asset exceeds its accounting basis (known as a deductible temporary difference). Conversely, deferred tax liabilities arise when the tax basis of an asset is less than its accounting basis (known as a taxable temporary difference). Deferred tax assets are recognized only to the extent that it is probable that there are future taxable profits against which the deductible temporary difference can be utilized. Deferred tax assets and liabilities are measured at the enacted or substantively enacted tax rate that is expected to apply when the asset is realized, or the liability is settled.

As such, fluctuations in deferred tax expenses and recoveries primarily arise as a result of: changes in the accounting basis of an asset or liability without a corresponding tax basis change (e.g. when derivative assets and liabilities are marked-to-market or when accounting depletion differs from tax depletion), changes in available tax losses (e.g. if they are utilized to offset taxable income), changes in estimated future taxable profits resulting in a derecognition or recognition of deferred tax assets, and changes in enacted or substantively enacted tax rates.

For the three and nine months ended September 30, 2024, the Company recorded deferred tax expense of \$4.7 million and \$42.0 million, respectively, compared to a deferred tax recovery of \$42.5 million and \$79.4 million, respectively, in the comparative periods in the prior year. The expense recorded in the current year is primarily attributable to the derecognition of deferred tax assets in Ireland driven by the decrease in European gas prices. In 2023, the deferred tax recovery was driven primarily by the disposition of assets in southeast Saskatchewan.

Financial Position Review

Balance sheet strategy

We regularly review whether our forecast of fund flows from operations is sufficient to finance planned capital expenditures, dividends, share buy-backs, and abandonment and reclamation expenditures. To the extent that fund flows from operations forecasts are not expected to be sufficient to fulfill such expenditures, we will evaluate our ability to finance any shortfall by reducing some or all categories of expenditures, with issuances of equity, and/or with debt (including borrowing using the unutilized capacity of our existing revolving credit facility). We have a long-term goal of maintaining a ratio of net debt to four quarter trailing fund flows from operations of approximately 1.0.

As at September 30, 2024, we have a ratio of net debt to four quarter trailing fund flows from operations of 0.6. We will continue to monitor for changes in forecasted fund flows from operations and, as appropriate, will adjust our exploration, development capital plans (and associated production targets), and return of capital plans to target optimal debt levels.

Net debt

Net debt is reconciled to long-term debt, as follows:

(\$M)	As at	
	Sep 30, 2024	Dec 31, 2023
Long-term debt	903,354	914,015
Adjusted working capital ⁽¹⁾	(70,023)	164,552
Net debt	833,331	1,078,567

Ratio of net debt to four quarter trailing fund flows from operations	0.6	0.9
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⁽¹⁾ Adjusted working capital is a non-GAAP financial measure that is not standardized under IFRS and may not be comparable to similar measures disclosed by other issuers. It is defined as current assets less current liabilities, excluding current derivatives and current lease liabilities. The measure is used to calculate net debt, a capital measure disclosed above. Reconciliation to the primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.

As at September 30, 2024, net debt decreased to \$833.3 million (December 31, 2023 - \$1.1 billion) primarily due to repurchases of senior notes and strong free cash flow generation. The ratio of net debt to four quarter trailing fund flows from operations as at September 30, 2024 decreased to 0.6 (December 31, 2023 - 0.9) due to lower net debt and higher four quarter trailing fund flows from operations.

Long-term debt

The balances recognized on our balance sheet are as follows:

	As at	
	Sep 30, 2024	Dec 31, 2023
2025 senior unsecured notes	373,469	395,839
2030 senior unsecured notes	529,885	518,176
Long-term debt	903,354	914,015

Revolving Credit Facility

As at September 30, 2024, Vermilion had in place a bank revolving credit facility maturing May 26, 2028 with terms and outstanding positions as follows:

(\$M)	As at	
	Sep 30, 2024	Dec 31, 2023
Total facility amount	1,350,000	1,600,000
Letters of credit outstanding	(21,886)	(18,116)
Unutilized capacity	1,328,114	1,581,884

On May 17, 2024, the maturity date of the facility was extended to May 26, 2028 (previously May 28, 2027) and the total facility amount of \$1.6 billion was reduced to \$1.35 billion, with an accordion feature to increase the aggregate amount available under the facility to \$1.6 billion. As at September 30, 2024, the revolving credit facility was undrawn.

As at September 30, 2024, the revolving credit facility was subject to the following financial covenants:

Financial covenant	Limit	As at	
		Sep 30, 2024	Dec 31, 2023
Consolidated total debt to consolidated EBITDA	Less than 4.0	0.68	0.65
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	0.05	—
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	17.81	17.33

Our financial covenants include financial measures defined within our revolving credit facility agreement that are not defined under IFRS. These financial measures are defined by our revolving credit facility agreement as follows:

- Consolidated total debt: Includes all amounts classified as "Long-term debt", "Current portion of long-term debt", and "Lease obligations" (including the current portion included within "Accounts payable and accrued liabilities" but excluding operating leases as defined under IAS 17) on our consolidated balance sheet.
- Consolidated total senior debt: Consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Consolidated net earnings (loss) before interest, income taxes, depreciation, accretion and certain other non-cash items, adjusted for the impact of the acquisition of a material subsidiary.
- Total interest expense: Includes all amounts classified as "Interest expense", but excludes interest on operating leases as defined under IAS 17.

In addition, our revolving credit facility has provisions relating to our liability management ratings in Alberta and Saskatchewan whereby if our security adjusted liability management ratings fall below specified limits in a province, a portion of the asset retirement obligations are included in the definitions of consolidated total debt and consolidated total senior debt. An event of default occurs if our security adjusted liability management ratings breach additional lower limits for a period greater than 90 days. As of September 30, 2024, Vermilion's liability management ratings were higher than the specified levels, and as such, no amounts relating to asset retirement obligations were included in the calculation of consolidated total debt and consolidated total senior debt.

As at September 30, 2024 and December 31, 2023, Vermilion was in compliance with the above covenants.

2025 senior unsecured notes

On March 13, 2017, Vermilion issued US \$300.0 million of senior unsecured notes at par. The notes bear interest at a rate of 5.625% per annum, paid semi-annually on March 15 and September 15, and mature on March 15, 2025. As direct senior unsecured obligations of Vermilion, the notes rank equally in right of payment with existing and future senior indebtedness of the Company.

The senior unsecured notes were recognized at amortized cost and include the transaction costs directly related to the issuance.

Subsequent to March 15, 2023, Vermilion may redeem some or all of the senior unsecured notes at a 100.00% redemption price plus any accrued and unpaid interest.

During the nine months ended September 30, 2024, Vermilion purchased \$31.6 million of senior unsecured notes on the open market which were subsequently cancelled.

The Company has the right to roll over the senior unsecured notes under the existing revolving credit facility which matures May 26, 2028 and thus has continued to classify the senior unsecured notes as non-current.

2030 senior unsecured notes

On April 26, 2022, Vermilion closed a private offering of US \$400.0 million 8-year senior unsecured notes. The notes were priced at 99.241% of par, mature on May 1, 2030, and bear interest at a rate of 6.875% per annum. Interest is paid semi-annually on May 1 and November 1, commencing on November 1, 2022. The notes are senior unsecured obligations of Vermilion and rank equally with existing and future senior unsecured indebtedness.

The senior unsecured notes were recognized at amortized cost and include the transaction costs directly related to the issuance.

Vermilion may, at its option, redeem the notes prior to maturity as follows:

- Prior to May 1, 2025, Vermilion may redeem up to 35% of the original principal amount of the notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price of 106.875% of the principal amount of the notes, together with accrued and unpaid interest.
- Prior to May 1, 2025, Vermilion may also redeem some or all of the notes at a price equal to 100% of the principal amount of the notes, plus a "make-whole premium," together with applicable premium, accrued and unpaid interest.
- On or after May 1, 2025, Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth below, together with accrued and unpaid interest.

Year	Redemption price
2025	103.438 %
2026	102.292 %
2027	101.146 %
2028 and thereafter	100.000 %

Shareholders' capital

The following table outlines our dividend payment history:

Date	Frequency	Dividend per unit or share
April 2022 to July 2022	Quarterly	\$0.06
August 2022 to March 2023	Quarterly	\$0.08
April 2023 to March 2024	Quarterly	\$0.10
April 2024 onwards	Quarterly	\$0.12

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Shares ('000s)	Amount (\$M)
Balance at January 1	162,271	4,142,566
Vesting of equity based awards	996	9,998
Share-settled dividends on vested equity based awards	78	1,257
Repurchase of shares	(7,997)	(206,154)
Balance at September 30	155,348	3,947,667

As at September 30, 2024, there were approximately 4.5 million equity based compensation awards outstanding. As at November 6, 2024, there were approximately 155.1 million common shares issued and outstanding.

On July 8, 2024, the Toronto Stock Exchange approved our notice of intention to renew our normal course issuer bid ("the NCIB"). The NCIB renewal allows Vermilion to purchase up to 15,689,839 common shares (representing approximately 10% of outstanding common shares) beginning July 12, 2024 and ending July 11, 2025. Common shares purchased under the NCIB will be cancelled.

In the third quarter of 2024, Vermilion purchased 2.8 million common shares under the NCIB for total consideration of \$40.1 million. Year-to-date, Vermilion purchased 8.0 million common shares under the NCIB for total consideration of 123.1 million. The common shares purchased under the NCIB were cancelled.

Subsequent to September 30, 2024, Vermilion purchased and cancelled 0.4 million shares under the NCIB for total consideration of \$5.9 million.

Contractual Obligations and Commitments

Further information regarding the Company's contractual obligations and commitments can be found in the annual MD&A for the year ended December 31, 2023, available on SEDAR+ at www.sedarplus.ca or on Vermilion's website at www.vermilionenergy.com.

Asset Retirement Obligations

As at September 30, 2024, asset retirement obligations were \$1,221.3 million compared to \$1,159.1 million as at December 31, 2023. The increase in asset retirement obligations is primarily attributable to accretion expense recognized and unfavourable foreign exchange impacts. The credit spread decreased to 3.3% at September 30, 2024 compared to 3.6% at December 31, 2023 primarily due to a lower expected cost of borrowing.

The present value of the obligation is calculated using a credit-adjusted risk-free rate, calculated using a credit spread added to risk-free rates based on long-term, risk-free government bonds. Vermilion's credit spread is determined using the Company's expected cost of borrowing at the end of the reporting period.

The risk-free rates and credit spread used as inputs to discount the obligations were as follows:

	Sep 30, 2024	Dec 31, 2023	Change
Credit spread added to below noted risk-free rates	3.3 %	3.6 %	(0.3)%
Country specific risk-free rate			
Canada	3.1 %	3.0 %	0.1 %
United States	4.1 %	4.2 %	(0.1)%
France	3.5 %	3.0 %	0.5 %
Netherlands	2.6 %	2.1 %	0.5 %
Germany	2.5 %	2.3 %	0.2 %
Ireland	2.7 %	2.7 %	— %
Australia	4.2 %	4.0 %	0.2 %
Central and Eastern Europe	4.5 %	4.4 %	0.1 %

Current cost estimates are inflated to the estimated time of abandonment using inflation rates of between 1.3% and 5.5% (as at December 31, 2023 - between 1.3% and 5.5%).

Risks and Uncertainties

Vermilion is exposed to various market and operational risks. For a discussion of these risks, please see Vermilion's MD&A and Annual Information Form, each for the year ended December 31, 2023 available on SEDAR+ at www.sedarplus.ca or on Vermilion's website at www.vermilionenergy.com.

Critical Accounting Estimates

The preparation of financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of any possible contingencies. These estimates and assumptions are developed based on the best available information which management believed to be reasonable at the time such estimates and assumptions were made. As such, these assumptions are uncertain at the time estimates are made and could change, resulting in a material impact on Vermilion's consolidated financial statements. Estimates are reviewed by management on an ongoing basis and as a result may change from period to period due to the availability of new information or changes in circumstances. Additionally, as a result of the unique circumstances of each jurisdiction that Vermilion operates in, the critical accounting estimates may affect one or more jurisdictions. There have been no material changes to our critical accounting estimates used in applying accounting policies for the nine months ended September 30, 2024. Further information, including a discussion of critical accounting estimates, can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2023, available on SEDAR+ at www.sedarplus.ca or on Vermilion's website at www.vermilionenergy.com.

Off Balance Sheet Arrangements

We have not entered into any guarantee or off balance sheet arrangements that would materially impact our financial position or results of operations.

Internal Control Over Financial Reporting

There has been no change in Vermilion's internal control over financial reporting ("ICFR") during the period covered by this MD&A that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Recently Adopted Accounting Pronouncements

Vermilion did not adopt any new accounting pronouncements as at September 30, 2024 that would have a material impact on the Consolidated Interim Financial Statements.

Regulatory Pronouncements Not Yet Adopted

Issuance of IFRS Sustainability Standards - IFRS S1 "General Requirements for Disclosure of Sustainability-related Financial Information" and IFRS S2 "Climate-related Disclosures"

In June 2023, the International Sustainability Standards Board (ISSB) issued its inaugural standards - IFRS S1 and IFRS S2. The ISSB was formed as a new standard-setting board within the IFRS Foundation to issue standards that deliver a comprehensive global baseline of sustainability-related financial disclosures, operating alongside the International Accounting Standards Board.

IFRS S1 and IFRS S2 are effective for annual reporting periods beginning on or after January 1, 2024, with earlier application permitted, as long as both standards are applied. IFRS S1 provides a set of disclosure requirements designed to enable companies to communicate to investors about the sustainability-related risks and opportunities, while IFRS S2 sets out specific climate-related disclosures and is designed to be used in conjunction with IFRS S1. Canadian regulators have not yet mandated these standards; however, Vermilion is continuing to review the impact of the standards on its financial reporting.

IFRS 18 "Presentation and Disclosure in Financial Statements issued"

In April 2024, the IASB issued IFRS 18 Presentation and Disclosure in Financial Statements which will replace IAS 1 Presentation of Financial Statements. Retrospective application of the standard is mandatory for annual reporting periods starting from January 1, 2027 onwards with earlier application is permitted. Vermilion is assessing the impacts of the standard on its financial reporting.

Disclosure Controls and Procedures

Our officers have established and maintained disclosure controls and procedures and evaluated the effectiveness of these controls in conjunction with our filings.

As of September 30, 2024, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based on this evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded and certified that our disclosure controls and procedures are effective.

Supplemental Table 1: Netbacks

The following table includes financial statement information on a per unit basis by business unit. Liquids includes crude oil, condensate, and NGLs. Natural gas sales volumes have been converted on a basis of six thousand cubic feet of natural gas to one barrel of oil equivalent.

	Q3 2024			Q2 2024			YTD 2024			Q3 2023	YTD 2023
	Liquids	Natural Gas	Total	Liquids	Natural Gas	Total	Liquids	Natural Gas	Total	Total	Total
	\$/bbl	\$/mcf	\$/boe	\$/bbl	\$/mcf	\$/boe	\$/bbl	\$/mcf	\$/boe	\$/boe	\$/boe
Canada											
Sales	75.97	0.88	38.06	83.40	1.29	42.58	77.79	1.42	40.51	45.52	47.36
Royalties	(10.58)	(0.01)	(4.95)	(11.07)	0.04	(4.98)	(10.63)	(0.05)	(5.06)	(5.84)	(5.57)
Transportation	(4.95)	(0.33)	(3.36)	(4.45)	(0.31)	(3.05)	(4.65)	(0.26)	(3.00)	(2.33)	(2.25)
Operating	(23.53)	(0.27)	(11.78)	(27.97)	(0.40)	(14.18)	(25.63)	(0.47)	(13.35)	(12.87)	(13.06)
Operating netback	36.91	0.27	17.97	39.91	0.62	20.37	36.88	0.64	19.10	24.48	26.48
General and administration			(0.27)			(1.22)			(1.49)	(5.56)	(5.09)
Fund flows from operations (\$/boe)			17.70			19.15			17.61	18.92	21.39
United States											
Sales	82.44	1.24	65.30	94.63	1.22	77.12	88.29	1.74	71.23	77.03	72.07
Royalties	(21.88)	(0.40)	(17.42)	(27.93)	(0.31)	(22.70)	(25.28)	(0.56)	(20.47)	(21.95)	(19.59)
Transportation	(1.08)	—	(0.83)	(1.25)	—	(1.00)	(1.08)	—	(0.85)	(0.27)	(0.19)
Operating	(16.14)	(0.28)	(12.84)	(14.37)	(0.04)	(11.54)	(16.37)	(0.30)	(13.18)	(6.35)	(10.84)
Operating netback	43.34	0.56	34.21	51.08	0.87	41.88	45.56	0.88	36.73	48.46	41.45
General and administration			(6.61)			(5.95)			(6.17)	(5.21)	(4.43)
Fund flows from operations (\$/boe)			27.60			35.93			30.56	43.25	37.02
France											
Sales	108.26	—	108.26	112.22	—	112.22	111.43	—	111.43	115.36	107.18
Royalties	(13.62)	—	(13.62)	(13.79)	—	(13.79)	(14.77)	—	(14.77)	(16.01)	(13.92)
Transportation	(9.11)	—	(9.11)	(8.59)	—	(8.59)	(8.10)	—	(8.10)	(5.64)	(8.63)
Operating	(23.49)	—	(23.49)	(19.59)	—	(19.59)	(23.52)	—	(23.52)	(28.28)	(29.01)
Operating netback	62.04	—	62.04	70.25	—	70.25	65.04	—	65.04	65.43	55.62
General and administration			(7.29)			(5.11)			(6.29)	(2.22)	(6.62)
Current income taxes			(3.69)			(7.99)			(6.53)	(7.01)	(3.87)
Fund flows from operations (\$/boe)			51.06			57.15			52.22	56.20	45.13
Netherlands											
Sales	106.74	14.67	88.18	103.64	12.31	74.19	91.80	12.89	77.59	74.00	109.30
Royalties	—	—	—	—	—	—	—	(0.03)	(0.17)	54.75	(0.71)
Transportation	—	—	—	—	—	—	—	—	—	—	—
Operating	15.61	(3.45)	(20.33)	(46.54)	(4.30)	(26.01)	(25.08)	(3.78)	(22.73)	(9.06)	(24.26)
Operating netback	122.35	11.22	67.85	57.10	8.01	48.18	66.72	9.08	54.69	119.69	84.33
General and administration			(5.24)			(4.31)			(4.47)	(17.60)	(6.26)
Current income taxes			(12.88)			(19.09)			(18.57)	(45.38)	(23.92)
Fund flows from operations (\$/boe)			49.73			24.78			31.65	56.71	54.15
Germany											
Sales	103.32	13.64	88.79	109.38	11.46	78.76	106.12	12.01	80.74	83.24	106.29
Royalties	(4.55)	(0.32)	(2.78)	0.31	(0.87)	(3.88)	(2.68)	(0.57)	(3.23)	0.32	(3.69)
Transportation	(15.19)	(0.42)	(6.62)	(17.74)	(0.46)	(6.45)	(18.66)	(0.47)	(6.86)	(8.13)	(6.92)
Operating	(33.51)	(4.64)	(29.68)	(53.89)	(5.69)	(38.98)	(40.03)	(4.63)	(30.91)	(31.01)	(25.02)
Operating netback	50.07	8.26	49.71	38.06	4.44	29.45	44.75	6.34	39.74	44.42	70.66
General and administration			(6.23)			(8.27)			(6.76)	(3.81)	(6.40)
Current income taxes			(4.96)			(4.60)			(6.62)	(18.34)	(21.81)
Fund flows from operations (\$/boe)			38.52			16.58			26.36	22.27	42.45

	Q3 2024			Q2 2024			YTD 2024			Q3 2023	YTD 2023
	Liquids	Natural Gas	Total	Liquids	Natural Gas	Total	Liquids	Natural Gas	Total	Total	Total
	\$/bbl	\$/mcf	\$/boe	\$/bbl	\$/mcf	\$/boe	\$/bbl	\$/mcf	\$/boe	\$/boe	\$/boe
Ireland											
Sales	—	14.60	87.60	—	13.29	79.76	—	13.21	79.23	86.76	94.92
Transportation	—	(0.42)	(2.54)	—	(0.46)	(2.75)	—	(0.48)	(2.88)	(3.48)	(2.84)
Operating	—	(2.51)	(15.05)	—	(3.13)	(18.80)	—	(2.52)	(15.09)	(14.10)	(11.99)
Operating netback	—	11.67	70.01	—	9.70	58.21	—	10.21	61.26	69.18	80.09
General and administration			(2.99)			(1.67)			(2.35)	(5.34)	(4.69)
Current income taxes			(0.19)			(0.36)			(0.35)	(0.22)	(0.18)
Fund flows from operations (\$/boe)			66.83			56.18			58.56	63.62	75.22
Australia											
Sales	128.84	—	128.84	131.06	—	131.06	130.39	—	130.39	—	—
Operating	(77.10)	—	(77.10)	(56.66)	—	(56.66)	(58.35)	—	(58.35)	—	—
PRRT ⁽¹⁾	(1.37)	—	(1.37)	(14.54)	—	(14.54)	(12.54)	—	(12.54)	—	—
Operating netback	50.37	—	50.37	59.86	—	59.86	59.50	—	59.50	—	—
General and administration			(5.59)			(8.01)			(4.88)	—	—
Current income taxes			(3.08)			(1.40)			(1.96)	—	—
Fund flows from operations (\$/boe)			41.70			50.45			52.66	—	—
Central and Eastern Europe											
Sales	—	15.76	94.59	62.27	14.44	84.76	62.04	15.63	93.67	73.37	156.78
Royalties	—	(2.30)	(13.83)	(5.49)	(3.81)	(21.53)	(5.47)	(2.38)	(14.23)	(160.33)	(88.38)
Operating	—	(0.69)	(4.11)	(38.46)	(5.92)	(33.51)	(5.47)	(1.36)	(8.13)	(263.59)	(68.00)
Operating netback	—	12.77	76.65	18.32	4.71	29.72	51.10	11.89	71.31	(350.55)	0.40
General and administration			(11.57)			(156.46)			(30.13)	(2,533.97)	(360.77)
Current income taxes			—			—			—	(1.36)	0.07
Fund flows from operations (\$/boe)			65.08			(126.74)			41.18	(2,885.88)	(360.30)
Total Company											
Sales	88.90	6.57	61.97	94.79	5.69	62.46	92.09	6.13	62.63	62.92	66.57
Realized hedging gain (loss)	2.23	1.62	6.31	(0.16)	1.90	6.00	1.10	4.04	13.42	9.74	6.91
Royalties	(8.57)	(0.46)	(5.40)	(11.80)	(0.18)	(6.08)	(11.66)	(0.12)	(5.85)	(4.26)	(6.51)
Transportation	(5.27)	(0.30)	(3.38)	(5.07)	(0.29)	(3.30)	(4.94)	(0.27)	(3.18)	(2.84)	(2.95)
Operating	(25.77)	(1.78)	(17.55)	(27.41)	(1.72)	(18.29)	(26.80)	(1.76)	(18.16)	(16.26)	(17.60)
PRRT ⁽²⁾	(0.14)	—	(0.06)	(1.02)	—	(0.47)	(1.35)	—	(0.63)	—	—
Operating netback	51.38	5.65	41.89	49.33	5.40	40.32	48.44	8.02	48.23	49.30	46.42
General and administration			(2.76)			(3.46)			(3.05)	(2.77)	(2.70)
Interest expense			(2.68)			(2.75)			(2.57)	(2.68)	(2.77)
Equity based compensation			—			(1.87)			(0.61)	—	—
Realized foreign exchange gain			0.15			0.30			0.22	0.28	0.04
Other income			(0.21)			(0.09)			(0.09)	(1.32)	(0.11)
Corporate income taxes			(1.61)			(1.58)			(2.14)	(4.15)	(3.22)
Windfall taxes			—			—			—	(2.90)	(3.47)
Fund flows from operations (\$/boe)			34.78			30.87			39.99	35.76	34.19

⁽¹⁾ Vermilion considers Australian PRRT to be an operating item and, accordingly, has included PRRT in the calculation of operating netbacks. Current income taxes presented above excludes PRRT.

Supplemental Table 2: Hedges

The prices in these tables may represent the weighted averages for several contracts with foreign currency amounts translated to the disclosure currency using forward rates as at the month-end date. The weighted average price for the portfolio of options listed below may not have the same payoff profile as the individual contracts. As such, the presentation of the weighted average prices is purely for indicative purposes.

The following tables outline Vermilion's outstanding risk management positions as at September 30, 2024:

	Unit	Currency	Daily Bought Put Volume	Weighted Average Bought Put Price	Daily Sold Call Volume	Weighted Average Sold Call Price	Daily Sold Put Volume	Weighted Average Sold Put Price	Daily Sold Swap Volume	Weighted Average Sold Swap Price	Daily Bought Swap Volume	Weighted Average Bought Swap Price
WTI												
Q4 2024	bbl	USD	—	—	—	—	—	—	11,000	79.27	—	—
Q1 2025	bbl	USD	—	—	—	—	—	—	3,500	77.14	—	—
AECO												
Q4 2024	mcf	CAD	4,739	3.17	4,739	4.22	—	—	9,849	3.31	—	—
Q1 2025	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q2 2025	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q3 2025	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q4 2025	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q1 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q2 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q3 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q4 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
AECO Basis (AECO less NYMEX Henry Hub)												
Q1 2025	mcf	USD	—	—	—	—	—	—	10,000	(1.15)	—	—
Q2 2025	mcf	USD	—	—	—	—	—	—	10,000	(1.15)	—	—
Q3 2025	mcf	USD	—	—	—	—	—	—	10,000	(1.15)	—	—
Q4 2025	mcf	USD	—	—	—	—	—	—	10,000	(1.15)	—	—
NYMEX Henry Hub												
Q4 2024	mcf	USD	20,000	3.50	20,000	4.45	—	—	4,000	3.51	—	—
Q1 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q2 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q3 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q4 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q1 2026	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q2 2026	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q3 2026	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q4 2026	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
TTF												
Q4 2024	mcf	EUR	17,197	10.06	17,197	14.88	6,142	3.28	39,308	14.52	—	—
Q1 2025	mcf	EUR	18,426	10.07	18,426	14.89	13,512	4.69	39,308	14.52	—	—
Q2 2025	mcf	EUR	22,111	8.31	22,111	12.86	22,111	4.01	24,567	12.99	—	—
Q3 2025	mcf	EUR	22,111	8.31	22,111	12.86	22,111	4.01	24,567	12.99	—	—
Q4 2025	mcf	EUR	31,938	8.05	31,938	12.49	31,938	3.67	20,882	11.87	—	—
Q1 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	20,882	11.87	—	—
Q2 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	18,426	9.60	—	—
Q3 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	18,426	9.60	—	—
Q4 2026	mcf	EUR	28,253	7.43	28,253	11.66	28,253	2.93	4,913	8.54	—	—
Q1 2027	mcf	EUR	28,253	7.43	28,253	11.66	28,253	2.93	4,913	8.54	—	—
THE												
Q4 2024	mcf	EUR	—	—	—	—	—	—	2,457	14.95	—	—
Q1 2025	mcf	EUR	—	—	—	—	—	—	2,457	14.95	—	—
Q2 2025	mcf	EUR	—	—	—	—	—	—	2,457	14.95	—	—
Q3 2025	mcf	EUR	—	—	—	—	—	—	2,457	14.95	—	—

VET Equity Swaps		Initial Share Price		Share Volume
Swap	Jan 2020 - Apr 2025	20.9788	CAD	2,250,000
Swap	Jan 2020 - Jul 2025	22.4587	CAD	1,500,000

Foreign Exchange		Period	Monthly Bought Put Amount	Weighted Average Bought Put Price	Monthly Sold Call Amount	Weighted Average Sold Call Price	Monthly Sold Swap Amount	Weighted Average Sold Swap Price
Forward	Sell USD, Buy CAD	Oct 2024 - Dec 2024	—	—	—	—	16,000,000 USD	1.3549
Collar	Sell USD, Buy CAD	Oct 2024 - Dec 2024	4,000,000 USD	1.3600	4,000,000 USD	1.3963	—	—
Collar	Sell USD, Buy CAD	Jan 2025 - Dec 2025	1,000,000 USD	1.3600	1,000,000 USD	1.4000	—	—

The following sold option instruments allow the counterparties, at the specified date, to enter into a derivative instrument contract with Vermilion at the detailed terms:

Period if Option Exercised	Unit	Currency	Option Expiration Date	Daily Bought Put Volume	Weighted Average Bought Put Price	Daily Sold Call Volume	Weighted Average Sold Call Price	Daily Sold Put Volume	Weighted Average Sold Put Price	Daily Sold Swap Volume	Weighted Average Sold Swap Price
WTI											
Jan 2025 - Dec 2025	bbl	USD	31-Dec-2024	—	—	—	—	—	—	2,000	80.00
NYMEX											
Jan 2025 - Dec 2025	mcf	USD	23-Dec-2024	—	—	—	—	—	—	10,000	3.65

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification (\$M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Drilling and development	118,809	119,404	410,457	436,802
Exploration and evaluation	2,460	6,235	11,864	10,502
Capital expenditures	121,269	125,639	422,321	447,304
Acquisitions, net of cash acquired	1,642	3,191	7,471	139,612
Acquisition of securities	—	2,047	9,373	4,155
Acquired working capital	—	—	—	103,527
Acquisitions	1,642	5,238	16,844	247,294
Dispositions (\$M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Canada	—	—	—	182,152
Total dispositions	—	—	—	182,152
By category (\$M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Drilling, completion, new well equip and tie-in, workovers and recompletions	80,676	59,989	258,173	305,020
Production equipment and facilities	39,121	56,979	150,250	121,394
Seismic, studies, land and other	1,472	8,671	13,898	20,890
Capital expenditures	121,269	125,639	422,321	447,304
Acquisitions	1,642	5,238	16,844	247,294
Total capital expenditures and acquisitions	122,911	130,877	439,165	694,598
Capital expenditures by country (\$M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Canada	76,799	59,111	260,288	234,432
United States	1,372	10,592	15,912	87,064
France	11,366	14,069	33,770	37,080
Netherlands	5,237	17,162	13,868	33,360
Germany	15,472	10,648	61,397	26,665
Ireland	345	6,994	3,794	8,433
Australia	8,661	6,072	23,641	16,674
Central and Eastern Europe	2,017	991	9,651	3,596
Total capital expenditures	121,269	125,639	422,321	447,304
Acquisitions by country (\$M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Canada	1,642	5,238	16,844	51,068
United States	—	—	—	3,808
Ireland	—	—	—	192,418
Acquisitions	1,642	5,238	16,844	247,294

Supplemental Table 4: Production

	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22	Q1/22	Q4/21
Canada												
Light and medium crude oil (bbls/d)	12,526	12,468	11,649	11,614	12,054	12,901	16,674	17,448	16,835	17,042	15,980	16,388
Condensate ⁽¹⁾ (bbls/d)	3,598	3,853	4,075	4,034	4,410	3,506	4,719	4,525	4,204	4,873	4,892	4,785
Other NGLs ⁽¹⁾ (bbls/d)	6,483	6,208	5,968	6,281	6,219	5,513	6,875	6,279	6,870	7,155	7,286	7,073
NGLs (bbls/d)	10,081	10,061	10,043	10,315	10,629	9,019	11,594	10,804	11,074	12,028	12,178	11,858
Conventional natural gas (mmcf/d)	156.99	158.48	151.84	160.16	163.94	159.26	160.34	146.81	145.04	143.94	140.55	128.85
Total (boe/d)	48,772	48,943	46,997	48,623	50,007	48,464	54,991	52,720	52,080	53,060	51,584	49,720
United States												
Light and medium crude oil (bbls/d)	2,909	3,817	3,483	3,187	4,404	3,349	2,824	3,282	2,824	2,846	2,675	2,647
Condensate ⁽¹⁾ (bbls/d)	12	27	29	27	15	22	20	36	35	40	24	26
Other NGLs ⁽¹⁾ (bbls/d)	1,064	988	1,078	1,131	1,124	1,025	1,020	1,218	1,031	958	1,056	1,388
NGLs (bbls/d)	1,076	1,015	1,107	1,158	1,139	1,047	1,040	1,254	1,066	998	1,080	1,414
Conventional natural gas (mmcf/d)	7.08	7.27	8.23	7.49	7.25	7.23	7.14	7.45	7.03	6.74	7.56	9.09
Total (boe/d)	5,164	6,044	5,962	5,593	6,751	5,601	5,055	5,779	5,062	4,967	5,014	5,575
France												
Light and medium crude oil (bbls/d)	7,115	7,246	7,308	7,395	7,578	7,788	7,578	7,247	6,818	8,126	8,389	8,453
Total (boe/d)	7,115	7,246	7,308	7,395	7,578	7,788	7,578	7,247	6,818	8,126	8,389	8,453
Netherlands												
Light and medium crude oil (bbls/d)	—	—	—	—	—	—	—	—	—	1	1	—
Condensate ⁽¹⁾ (bbls/d)	39	51	165	119	39	61	66	49	74	60	83	97
NGLs (bbls/d)	39	51	165	119	39	61	66	49	74	60	83	97
Conventional natural gas (mmcf/d)	25.06	26.84	31.02	32.06	24.32	27.28	29.07	27.41	29.15	35.22	39.03	51.98
Total (boe/d)	4,216	4,524	5,336	5,462	4,091	4,607	4,910	4,617	4,933	5,930	6,589	8,761
Germany												
Light and medium crude oil (bbls/d)	1,598	1,698	1,722	1,775	1,713	1,715	1,410	1,481	1,764	1,331	1,158	1,127
Conventional natural gas (mmcf/d)	21.41	18.41	22.87	19.62	20.29	22.05	25.85	25.86	26.54	25.36	26.95	18.00
Total (boe/d)	5,167	4,766	5,533	5,046	5,095	5,391	5,717	5,791	6,187	5,558	5,650	4,127
Ireland												
Conventional natural gas (mmcf/d)	59.06	57.70	60.34	64.04	47.96	67.51	24.58	26.04	25.74	27.93	30.26	30.12
Total (boe/d)	9,844	9,616	10,057	10,673	7,993	11,251	4,096	4,340	4,290	4,655	5,043	5,020
Australia												
Light and medium crude oil (bbls/d)	2,040	3,713	4,264	4,715	1,204	—	—	4,847	4,763	2,465	3,888	2,742
Total (boe/d)	2,040	3,713	4,264	4,715	1,204	—	—	4,847	4,763	2,465	3,888	2,742
Central and Eastern Europe												
Conventional natural gas (mmcf/d)	11.13	0.69	0.29	0.54	0.05	0.30	0.64	0.67	0.63	0.64	0.34	0.12
Total (boe/d)	1,855	122	48	90	8	50	107	111	104	106	57	20
Consolidated												
Light and medium crude oil (bbls/d)	26,188	28,948	28,426	28,685	26,952	25,753	28,485	34,305	33,003	31,811	32,091	31,356
Condensate ⁽¹⁾ (bbls/d)	3,649	3,931	4,269	4,180	4,463	3,589	4,805	4,610	4,312	4,973	4,999	4,908
Other NGLs ⁽¹⁾ (bbls/d)	7,547	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901	8,113	8,342	8,461
NGLs (bbls/d)	11,196	11,127	11,315	11,592	11,807	10,127	12,701	12,107	12,213	13,086	13,341	13,369
Conventional natural gas (mmcf/d)	280.73	269.39	274.59	283.91	263.80	283.63	247.61	234.23	234.12	239.83	244.69	238.16
Total (boe/d)	84,173	84,974	85,505	87,597	82,727	83,152	82,455	85,450	84,237	84,868	86,213	84,417

	YTD 2024	2023	2022	2021	2020	2019
Canada						
Light and medium crude oil (bbls/d)	12,218	13,293	16,830	16,954	21,106	23,971
Condensate ⁽¹⁾ (bbls/d)	3,841	4,166	4,621	4,831	4,886	4,295
Other NGLs ⁽¹⁾ (bbls/d)	6,221	6,220	6,895	7,179	7,719	6,988
NGLs (bbls/d)	10,062	10,386	11,516	12,010	12,605	11,283
Conventional natural gas (mmcf/d)	155.79	160.94	144.10	138.03	151.38	148.35
Total (boe/d)	48,240	50,503	52,364	51,968	58,942	59,979
United States						
Light and medium crude oil (bbls/d)	3,401	3,445	2,908	2,597	3,046	2,514
Condensate ⁽¹⁾ (bbls/d)	23	21	34	8	5	18
Other NGLs ⁽¹⁾ (bbls/d)	1,043	1,076	1,066	1,146	1,218	996
NGLs (bbls/d)	1,066	1,097	1,100	1,154	1,223	1,014
Conventional natural gas (mmcf/d)	7.52	7.28	7.20	6.84	7.47	6.89
Total (boe/d)	5,721	5,754	5,207	4,890	5,514	4,675
France						
Light and medium crude oil (bbls/d)	7,223	7,584	7,639	8,799	8,903	10,435
Conventional natural gas (mmcf/d)	—	—	—	—	—	0.19
Total (boe/d)	7,223	7,584	7,639	8,799	8,903	10,467
Netherlands						
Light and medium crude oil (bbls/d)	—	—	—	3	1	3
Condensate ⁽¹⁾ (bbls/d)	85	71	66	97	88	88
NGLs (bbls/d)	85	71	66	97	88	88
Conventional natural gas (mmcf/d)	27.63	28.18	32.66	43.40	46.16	49.10
Total (boe/d)	4,690	4,768	5,510	7,334	7,782	8,274
Germany						
Light and medium crude oil (bbls/d)	1,672	1,654	1,435	1,044	968	917
Conventional natural gas (mmcf/d)	20.90	21.93	26.18	15.81	12.65	15.31
Total (boe/d)	5,155	5,310	5,798	3,679	3,076	3,468
Ireland						
Conventional natural gas (mmcf/d)	59.03	51.12	27.48	29.25	37.44	46.57
Total (boe/d)	9,839	8,520	4,579	4,875	6,240	7,762
Australia						
Light and medium crude oil (bbls/d)	3,334	1,492	3,995	3,810	4,416	5,662
Total (boe/d)	3,334	1,492	3,995	3,810	4,416	5,662
Central and Eastern Europe						
Conventional natural gas (mmcf/d)	4.06	0.38	0.57	0.31	1.90	0.42
Total (boe/d)	679	63	95	51	317	70
Consolidated						
Light and medium crude oil (bbls/d)	27,848	27,469	32,809	33,208	38,441	43,502
Condensate ⁽¹⁾ (bbls/d)	3,949	4,258	4,721	4,936	4,980	4,400
Other NGLs ⁽¹⁾ (bbls/d)	7,264	7,296	7,961	8,325	8,937	7,984
NGLs (bbls/d)	11,213	11,554	12,682	13,261	13,917	12,384
Conventional natural gas (mmcf/d)	274.93	269.84	238.18	233.64	256.99	266.82
Total (boe/d)	84,881	83,994	85,187	85,408	95,190	100,357

Under National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities", disclosure of production volumes should include segmentation by product type as defined in the instrument. This table provides a reconciliation from "crude oil and condensate", "NGLs" and "natural gas" to the product types. In this report, references to "crude oil" and "light and medium crude oil" mean "light crude oil and medium crude oil" and references to "natural gas" mean "conventional natural gas". Production volumes reported are based on quantities as measured at the first point of sale.

Supplemental Table 5: Operational and Financial Data by Core Region

Production volumes ⁽¹⁾

	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22	Q1/22	Q4/21
North America												
Crude oil and condensate (bbls/d)	19,045	20,165	19,236	18,862	20,883	19,778	24,237	25,291	23,898	24,801	23,571	23,846
NGLs (bbls/d)	7,547	7,196	7,046	7,412	7,344	6,538	7,895	7,497	7,901	8,113	8,342	8,461
Natural gas (mmcf/d)	164.07	165.75	160.07	167.65	171.19	166.49	167.48	154.26	152.07	150.68	148.11	137.93
Total (boe/d)	53,936	54,987	52,959	54,216	56,758	54,065	60,046	58,499	57,142	58,027	56,598	55,295
International												
Crude oil and condensate (bbls/d)	10,792	12,714	13,459	14,004	10,534	9,564	9,054	13,624	13,419	11,983	13,519	12,419
Natural gas (mmcf/d)	116.66	103.64	114.52	116.27	92.61	117.14	80.13	79.97	82.05	89.15	96.58	100.22
Total (boe/d)	30,237	29,987	32,546	33,381	25,969	29,087	22,408	26,953	27,095	26,840	29,616	29,123
Consolidated												
Crude oil and condensate (bbls/d)	29,837	32,879	32,695	32,866	31,416	29,341	33,290	38,915	37,315	36,784	37,090	36,264
NGLs (bbls/d)	7,547	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901	8,113	8,342	8,461
Natural gas (mmcf/d)	280.73	269.39	274.59	283.92	263.80	283.63	247.61	234.23	234.12	239.83	244.69	238.16
Total (boe/d)	84,173	84,974	85,505	87,597	82,727	83,152	82,455	85,450	84,237	84,868	86,213	84,417

⁽¹⁾ Please refer to Supplemental Table 4 "Production" for disclosure by product type.

Sales volumes

	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22	Q1/22	Q4/21
North America												
Crude oil and condensate (bbls/d)	19,044	20,166	19,235	18,862	20,883	19,778	24,237	25,291	23,897	24,801	23,571	23,845
NGLs (bbls/d)	7,547	7,196	7,045	7,412	7,344	6,538	7,895	7,497	7,901	8,113	8,342	8,461
Natural gas (mmcf/d)	164.07	165.75	160.07	167.65	171.19	166.49	167.48	154.26	152.07	150.68	148.11	137.93
Total (boe/d)	53,936	54,987	52,960	54,216	56,758	54,065	60,046	58,499	57,142	58,027	56,598	55,295
International												
Crude oil and condensate (bbls/d)	12,580	11,998	15,938	9,221	9,950	10,302	8,087	16,257	11,493	11,720	12,615	13,985
Natural gas (mmcf/d)	116.66	103.64	114.52	116.27	92.61	117.14	80.13	79.97	82.05	89.15	96.58	100.22
Total (boe/d)	32,024	29,271	35,026	28,598	25,386	29,824	21,442	29,585	25,169	26,578	28,712	30,689
Consolidated												
Crude oil and condensate (bbls/d)	31,624	32,163	35,174	28,083	30,833	30,080	32,324	41,547	35,391	36,522	36,186	37,830
NGLs (bbls/d)	7,547	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901	8,113	8,342	8,461
Natural gas (mmcf/d)	280.73	269.39	274.59	283.92	263.80	283.63	247.61	234.23	234.12	239.83	244.69	238.16
Total (boe/d)	85,960	84,258	87,985	82,814	82,144	83,889	81,489	88,083	82,312	84,607	85,310	85,984

Financial results

	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22	Q1/22	Q4/21
North America												
Crude oil and condensate sales (\$/bbl)	96.54	104.57	91.50	100.16	103.46	94.78	95.63	106.66	114.82	134.72	111.42	92.99
NGL sales (\$/bbl)	27.49	31.61	34.16	33.38	27.77	28.11	36.24	39.93	44.64	51.86	46.94	47.26
Natural gas sales (\$/mcf)	0.90	1.29	2.14	2.62	2.52	2.29	4.11	5.96	6.41	7.13	4.80	5.07
Sales (\$/boe)	40.67	46.37	44.25	47.51	49.26	45.12	54.84	66.95	71.24	83.34	65.88	59.97
Royalties (\$/boe)	(6.14)	(6.93)	(7.03)	(7.25)	(7.75)	(5.45)	(7.68)	(9.47)	(12.58)	(12.51)	(11.24)	(9.26)
Transportation (\$/boe)	(3.12)	(2.82)	(2.35)	(2.44)	(2.08)	(1.57)	(2.44)	(2.42)	(2.16)	(2.15)	(1.91)	(1.86)
Operating (\$/boe)	(11.88)	(13.89)	(14.25)	(11.50)	(12.09)	(12.22)	(14.10)	(13.51)	(14.00)	(11.58)	(11.95)	(11.68)
General and administration (\$/boe)	(1.09)	(2.54)	(1.70)	0.87	(0.72)	0.10	(0.99)	0.10	(1.27)	(1.52)	(1.26)	(2.01)
Corporate income taxes (\$/boe)	(0.34)	0.82	(0.65)	0.23	(0.01)	(0.10)	(0.12)	(0.13)	(0.03)	—	(0.02)	0.42
Fund flows from operations (\$/boe)	18.10	21.01	18.27	27.42	26.61	25.88	29.51	41.52	41.20	55.58	39.50	35.58
Fund flows from operations	89,793	105,187	88,027	136,766	138,960	127,346	159,435	223,443	216,579	293,470	201,193	180,979
Drilling and development	(78,171)	(61,520)	(136,509)	(58,704)	(69,703)	(135,723)	(116,070)	(113,892)	(112,238)	(54,913)	(57,513)	(89,643)
Free cash flow	11,622	43,667	(48,482)	78,062	69,257	(8,377)	43,365	109,551	104,341	238,557	143,680	91,336
International												
Crude oil and condensate sales (\$/bbl)	114.16	116.24	119.68	123.77	114.26	100.23	107.57	128.02	140.09	146.67	136.69	103.53
Natural gas sales (\$/mcf)	14.55	12.72	11.63	16.92	13.34	14.58	24.69	39.54	58.55	32.33	36.75	35.54
Sales (\$/boe)	97.85	92.68	92.48	108.70	93.46	91.89	132.84	177.23	254.86	173.14	183.66	163.23
Royalties (\$/boe)	(4.16)	(4.49)	(4.60)	(3.41)	3.55	(7.43)	(13.39)	(6.38)	(7.21)	(7.23)	(5.43)	(4.13)
Transportation (\$/boe)	(3.81)	(4.20)	(3.65)	(3.91)	(4.53)	(5.23)	(5.11)	(3.29)	(3.51)	(3.64)	(2.91)	(3.40)
Operating (\$/boe)	(27.11)	(26.56)	(25.30)	(22.64)	(25.58)	(28.24)	(31.41)	(23.35)	(22.63)	(22.11)	(19.86)	(18.86)
General and administration (\$/boe)	(5.56)	(5.20)	(4.86)	(9.18)	(7.37)	(7.58)	(7.52)	(5.09)	(3.34)	(3.16)	(3.02)	(2.53)
Corporate income taxes (\$/boe)	(3.74)	(6.08)	(7.06)	(7.81)	(13.42)	(6.79)	(11.20)	(15.15)	(21.97)	(28.73)	(17.63)	(12.17)
PRRT (\$/boe)	(0.17)	(1.37)	(3.38)	7.93	—	—	—	(1.85)	(1.96)	(0.83)	(2.60)	(1.96)
Fund flows from operations (\$/boe)	53.30	44.78	43.63	69.68	46.11	36.62	64.21	122.12	194.24	107.44	132.21	120.18
Fund flows from operations	157,048	119,310	139,054	183,353	107,706	99,377	123,893	332,377	449,771	259,840	341,626	339,286
Drilling and development	(40,638)	(47,830)	(45,789)	(73,604)	(49,701)	(28,347)	(37,258)	(43,957)	(65,640)	(54,575)	(25,328)	(29,359)
Exploration and evaluation	(2,460)	(1,260)	(8,144)	(10,579)	(6,235)	(2,775)	(1,492)	(11,456)	(6,137)	(3,665)	(2,503)	(26,805)
Free cash flow	113,950	70,220	85,121	99,170	51,770	68,255	85,143	276,964	377,994	201,600	313,795	283,122

	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22	Q1/22	Q4/21
Consolidated												
Crude oil and condensate sales (\$/bbl)	103.55	108.93	104.26	107.91	106.94	96.64	98.62	115.02	123.02	138.55	120.23	96.88
NGL sales (\$/bbl)	27.49	31.61	34.16	33.38	27.77	28.11	36.23	39.93	44.64	51.86	46.94	47.26
Natural gas sales (\$/mcf)	6.57	5.69	6.10	8.48	6.32	7.37	10.77	17.43	24.68	16.50	17.41	17.89
Sales (\$/boe)	61.97	62.46	63.45	68.64	62.92	61.74	75.36	103.99	127.39	111.55	105.52	96.82
Royalties (\$/boe)	(5.40)	(6.08)	(6.06)	(5.93)	(4.26)	(6.16)	(9.18)	(8.43)	(10.94)	(10.85)	(9.29)	(7.43)
Transportation (\$/boe)	(3.38)	(3.30)	(2.87)	(2.95)	(2.84)	(2.87)	(3.14)	(2.71)	(2.57)	(2.62)	(2.25)	(2.41)
Operating (\$/boe)	(17.55)	(18.29)	(18.65)	(15.35)	(16.26)	(17.91)	(18.66)	(16.81)	(16.64)	(14.89)	(14.61)	(14.24)
General and administration (\$/boe)	(2.76)	(3.46)	(2.96)	(2.60)	(2.77)	(2.63)	(2.71)	(1.65)	(1.90)	(2.04)	(1.85)	(2.20)
Corporate income taxes (\$/boe)	(1.61)	(1.58)	(3.20)	(2.54)	(4.15)	(2.48)	(3.04)	(5.18)	(6.74)	(9.03)	(5.95)	(4.07)
Windfall taxes (\$/boe)	—	—	—	(0.03)	(2.90)	(4.56)	(2.92)	(27.50)	—	—	—	—
PRRT (\$/boe)	(0.06)	(0.47)	(1.35)	2.74	—	—	—	(0.62)	(0.60)	(0.26)	(0.87)	(0.70)
Interest (\$/boe)	(2.68)	(2.75)	(2.30)	(3.01)	(2.68)	(2.65)	(2.98)	(2.78)	(3.23)	(2.74)	(1.93)	(2.06)
Equity based compensation (\$/boe)	—	(1.87)	—	—	—	—	—	—	—	—	—	—
Realized derivatives (\$/boe)	6.31	6.00	27.55	10.33	9.74	8.86	1.95	(5.42)	(18.22)	(10.36)	(18.78)	(23.97)
Realized foreign exchange (\$/boe)	0.15	0.30	0.23	(0.73)	0.28	0.48	(0.65)	2.33	(0.28)	(0.30)	0.10	(0.30)
Realized other (\$/boe)	(0.21)	(0.09)	0.02	0.26	(1.32)	0.53	0.49	(0.14)	0.80	0.36	0.70	1.29
Fund flows from operations (\$/boe)	34.78	30.87	53.86	48.83	35.76	32.35	34.52	35.08	67.07	58.82	50.79	40.73
Fund flows from operations	275,024	236,703	431,358	372,117	270,218	247,109	253,167	284,220	507,876	452,901	389,868	322,173
Drilling and development	(118,809)	(109,350)	(182,298)	(132,308)	(119,404)	(164,070)	(153,328)	(157,849)	(177,878)	(109,488)	(82,841)	(119,002)
Exploration and evaluation	(2,460)	(1,260)	(8,144)	(10,579)	(6,235)	(2,775)	(1,492)	(11,456)	(6,137)	(3,665)	(2,503)	(26,805)
Free cash flow	153,755	126,093	240,916	229,230	144,579	80,264	98,347	114,915	323,861	339,748	304,524	176,366

Non-GAAP and Other Specified Financial Measures

This MD&A includes references to certain financial measures which do not have standardized meanings and may not be comparable to similar measures presented by other issuers. These financial measures include fund flows from operations, a total of segments measure of profit or loss in accordance with IFRS 8 “Operating Segments” (please see Segmented Information in the Notes to the condensed Consolidated Interim Financial Statements) and net debt, a capital management measure in accordance with IAS 1 “Presentation of Financial Statements” (please see Capital Disclosures in the Notes to the condensed Consolidated Interim Financial Statements).

In addition, this MD&A includes financial measures which are not specified, defined, or determined under IFRS and are therefore considered non-GAAP financial measures and may not be comparable to similar measures presented by other issuers. These non-GAAP financial measures include:

Total of Segments Measure

Fund flows from operations (FFO): Most directly comparable to net earnings (loss), FFO is a total of segments measure comprised of sales less royalties, transportation, operating, G&A, corporate income tax, PRRT, windfall taxes, interest expense, equity based compensation settled in cash, realized gain (loss) on derivatives, realized foreign exchange gain (loss), and realized other income (expense). The measure is used to assess the contribution of each business unit to Vermilion's ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments. Reconciliation to the primary financial statement measures can be found below.

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Sales	490,095	61.97	475,532	62.92	1,477,055	62.63	1,499,586	66.57
Royalties	(42,738)	(5.40)	(32,209)	(4.26)	(137,901)	(5.85)	(146,546)	(6.51)
Transportation	(26,693)	(3.38)	(21,460)	(2.84)	(74,972)	(3.18)	(66,415)	(2.95)
Operating	(138,806)	(17.55)	(122,870)	(16.26)	(428,347)	(18.16)	(396,444)	(17.60)
General and administration	(21,803)	(2.76)	(20,959)	(2.77)	(72,043)	(3.05)	(60,906)	(2.70)
Corporate income tax expense	(12,707)	(1.61)	(31,368)	(4.15)	(50,445)	(2.14)	(72,558)	(3.22)
Windfall taxes	—	—	(21,953)	(2.90)	—	—	(78,177)	(3.47)
PRRT	(507)	(0.06)	—	—	(14,928)	(0.63)	—	—
Interest expense	(21,187)	(2.68)	(20,218)	(2.68)	(60,641)	(2.57)	(62,303)	(2.77)
Equity based compensation	—	—	—	—	(14,361)	(0.61)	—	—
Realized gain on derivatives	49,891	6.31	73,625	9.74	316,523	13.42	155,628	6.91
Realized foreign exchange gain	1,155	0.15	2,089	0.28	5,293	0.22	997	0.04
Realized other income	(1,676)	(0.21)	(9,991)	(1.32)	(2,148)	(0.09)	(2,368)	(0.11)
Fund flows from operations	275,024	34.78	270,218	35.76	943,085	39.99	770,494	34.19
Equity based compensation	(6,412)		(6,362)		(8,070)		(34,885)	
Unrealized (loss) gain on derivative instruments ⁽¹⁾	(1,052)		(65,294)		(315,585)		38,581	
Unrealized foreign exchange gain (loss) ⁽¹⁾	(11,382)		(12,042)		(29,954)		7,604	
Accretion	(19,126)		(20,068)		(55,269)		(58,718)	
Depletion and depreciation	(180,164)		(151,087)		(519,782)		(453,607)	
Deferred tax (expense) recovery	(4,713)		42,489		(42,025)		79,435	
Gain on business combination	—		—		—		445,094	
Loss on disposition	—		—		—		(226,828)	
Unrealized other expense ⁽¹⁾	(478)		(545)		(823)		(1,621)	
Net earnings (loss)	51,697		57,309		(28,423)		565,549	

⁽¹⁾ Unrealized (loss) gain on derivative instruments, Unrealized foreign exchange (loss) gain, and Unrealized other expense are line items from the respective Consolidated Statements of Cash Flows.

Non-GAAP Financial Measures and Non-GAAP Ratios

Free cash flow (FCF): Most directly comparable to cash flows from operating activities, FCF is a non-GAAP measure calculated as fund flows from operations less drilling and development costs and exploration and evaluation costs. FCF is used by management to determine the funding available for investing and financing activities including payment of dividends, repayment of long-term debt, reallocation into existing business units and deployment into new ventures. Reconciliation to the primary financial statement measures can be found in the following table.

(\$M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Cash flows from operating activities	134,547	118,436	755,164	680,697
Changes in non-cash operating working capital	125,145	138,200	155,869	61,768
Asset retirement obligations settled	15,332	13,582	32,052	28,029
Fund flows from operations	275,024	270,218	943,085	770,494
Drilling and development	(118,809)	(119,404)	(410,457)	(436,802)
Exploration and evaluation	(2,460)	(6,235)	(11,864)	(10,502)
Free cash flow	153,755	144,579	520,764	323,190

Capital expenditures: Most directly comparable to cash flows used in investing activities, capital expenditures is a non-GAAP measure calculated as the sum of drilling and development costs and exploration and evaluation costs as derived from the Consolidated Statements of Cash Flows. We consider capital expenditures to be a useful measure of our investment in our existing asset base. Capital expenditures are also referred to as E&D capital. Reconciliation to the primary financial statement measures can be found below.

(\$M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Drilling and development	118,809	119,404	410,457	436,802
Exploration and evaluation	2,460	6,235	11,864	10,502
Capital expenditures	121,269	125,639	422,321	447,304

Payout and payout % of FFO: Payout and payout % of FFO are, respectively, a non-GAAP financial measure and non-GAAP ratio, most directly comparable to dividends declared. Payout is comprised of dividends declared plus drilling and development costs, exploration and evaluation costs, and asset retirement obligations settled, and payout % of FFO is calculated as payout divided by FFO (total of segments measure). The measure is used by management to assess the amount of cash distributed back to shareholders and reinvested in the business for maintaining production and organic growth. Payout as a percentage of FFO is also referred to as the payout ratio or sustainability ratio. The reconciliation of the measure to the primary financial statement measure can be found below.

(\$M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Dividends declared	18,642	16,367	56,806	49,023
Drilling and development	118,809	119,404	410,457	436,802
Exploration and evaluation	2,460	6,235	11,864	10,502
Asset retirement obligations settled	15,332	13,582	32,052	28,029
Payout	155,243	155,588	511,179	524,356
% of fund flows from operations	56 %	58 %	54 %	68 %

Return on capital employed (ROCE): A non-GAAP ratio, ROCE is a measure that we use to analyze our profitability and the efficiency of our capital allocation process; the comparable primary financial statement measure is earnings before income taxes. ROCE is calculated by dividing net earnings (loss) before interest and taxes ("EBIT") by average capital employed over the preceding twelve months. Capital employed is calculated as total assets less current liabilities while average capital employed is calculated using the balance sheets at the beginning and end of the twelve-month period.

(\$M)	Twelve Months Ended	
	Sep 30, 2024	Sep 30, 2023
Net (loss) earnings	(831,559)	960,957
Taxes	(4,597)	537,895
Interest expense	83,550	84,809
EBIT	(752,606)	1,583,661
Average capital employed	5,995,108	6,024,614
Return on capital employed	(13)%	26 %

Adjusted working capital: Defined as current assets less current liabilities, excluding current derivatives and current lease liabilities. The measure is used by management to calculate net debt, a capital management measure disclosed below.

(\$M)	As at	
	Sep 30, 2024	Dec 31, 2023
Current assets	651,197	823,514
Current derivative asset	(92,537)	(313,792)
Current liabilities	(521,669)	(696,074)
Current lease liability	23,545	21,068
Current derivative liability	9,487	732
Adjusted working capital	70,023	(164,552)

Acquisitions: The sum of acquisitions, net of cash acquired and acquisitions of securities from the Consolidated Statements of Cash Flows, Vermilion common shares issued as consideration, the estimated value of contingent consideration, the amount of acquiree's outstanding long-term debt assumed, and net acquired working capital deficit or surplus. We believe that including these components provides a useful measure of the economic investment associated with our acquisition activity and is most directly comparable to cash flows used in investing activities. A reconciliation to the acquisitions line items in the Consolidated Statements of Cash Flows can be found below.

(\$M)	Q3 2024	Q3 2023	Q3 2024	Q3 2023
Acquisitions, net of cash acquired	1,642	3,191	7,471	139,612
Acquisition of securities	—	2,047	9,373	4,155
Acquired working capital	—	—	—	103,527
Acquisitions	1,642	5,238	16,844	247,294

Capital Management Measure

Net debt: Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements" that is most directly comparable to long-term debt. Net debt is comprised of long-term debt (excluding unrealized foreign exchange on swapped USD borrowings) plus adjusted working capital (defined as current assets less current liabilities, excluding current derivatives and current lease liabilities), and represents Vermilion's net financing obligations after adjusting for the timing of working capital fluctuations.

(\$M)	As at	
	Sep 30, 2024	Dec 31, 2023
Long-term debt	903,354	914,015
Adjusted working capital	(70,023)	164,552
Net debt	833,331	1,078,567
Ratio of net debt to four quarter trailing fund flows from operations	0.6	0.9

Supplementary Financial Measures

Diluted shares outstanding: The sum of shares outstanding at the period end plus outstanding awards under the Long-term Incentive Plan ("LTIP"), based on current estimates of future performance factors and forfeiture rates.

('000s of shares)	Q3 2024	Q3 2023
Shares outstanding	155,348	163,666
Potential shares issuable pursuant to the LTIP	3,564	4,238
Diluted shares outstanding	158,912	167,904

Fund flows from operations per basic and diluted share: Management assesses fund flows from operations on a per share basis as we believe this provides a measure of our operating performance after taking into account the issuance and potential future issuance of Vermilion common shares. Fund flows from operations per basic share is calculated by dividing fund flows from operations (total of segments measure) by the basic weighted average shares outstanding as defined under IFRS. Fund flows from operations per diluted share is calculated by dividing fund flows from operations by the sum of basic weighted average shares outstanding and incremental shares issuable under the equity based compensation plans as determined using the treasury stock method.

Operating netback: Most directly comparable to net earnings (loss), operating netback is calculated as sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses presented on a per unit basis. Management assesses operating netback as a measure of the profitability and efficiency of our field operations.

Fund flows from operations per boe: Management uses fund flows from operations per boe to assess the profitability of our business units and Vermilion as a whole. Fund flows from operations per boe is calculated by dividing fund flows from operations (total of segments measure) by boe production.

Net debt to four quarter trailing fund flows from operations: Management uses net debt to four quarter trailing fund flows from operations to assess the Company's ability to repay debt. Net debt to four quarter trailing fund flows from operations is calculated as net debt (capital management measure) divided by fund flows from operations (total of segments measure) from the preceding four quarters.

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Katy, Texas

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Halifax, Nova Scotia

¹ Chairman (Independent)

² Audit Committee Chair (Independent)

³ Audit Committee Member (Independent)

⁴ Governance and Human Resources Committee Chair (Independent)

⁵ Governance and Human Resources Committee Member (Independent)

⁶ Health, Safety and Environment Committee Chair (Independent)

⁷ Health, Safety and Environment Committee Member (Independent)

⁸ Technical Committee Chair (Independent)

⁹ Technical Committee Member (Independent)

¹⁰ Sustainability Committee Chair (Independent)

¹¹ Sustainability Committee Member (Independent)

OFFICERS / CORPORATE SECRETARY

Dion Hatcher *
President & Chief Executive Officer

Lars Glemser *
Vice President & Chief Financial Officer

Tamar Epstein
General Counsel & Corporate Secretary

Terry Hergott
Vice President Marketing

Yvonne Jeffery
Vice President Sustainability

Darcy Kerwin *
Vice President International & HSE

Geoff MacDonald
Vice President Geosciences

Randy McQuaig *
Vice President North America

Kyle Preston
Vice President Investor Relations

Averyl Schraven
Vice President People & Culture

Gerard Schut
Vice President European Operations

* Principal Executive Committee Member

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

The Bank of Nova Scotia

Canadian Imperial Bank of Commerce

National Bank of Canada

Royal Bank of Canada

Wells Fargo Bank N.A., Canadian Branch

ATB Financial

Bank of America N.A., Canada Branch

Export Development Canada

Fédération des caisses Desjardins du Québec

Citibank, N.A., Canadian Branch

Canadian Western Bank

JPMorgan Chase Bank, N.A., Toronto Branch

Goldman Sachs Lending Partners LLC

EVALUATION ENGINEERS

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LEGAL COUNSEL

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TRANSFER AGENT

Odyssey Trust Company

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