Q2 2025

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 2025 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 2025 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 fund flows 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 and the timing of regulatory proceedings and approvals.

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. References to Vermilion or the Company in this document include Westbrick Energy Ltd. ("Westbrick" or "Westbrick Energy") which was acquired by Vermilion Energy Inc. on February 26, 2025.

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.

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)
bbl(s)/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
CO2	carbon dioxide
CO2e	carbon dioxide equivalent
GHG	greenhouse gas
GJ	gigajoules
LSB	light sour blend crude oil reference price
mbbls	thousand barrels
mmboe	thousand barrels of oil equivalent
mmbtu	million British Thermal Units
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
MD	measured depth
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
psi	pounds per square inch
tCO2e	tonne 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
US	the United States of America
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 August 7, 2025, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three and six months ended June 30, 2025 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 six months ended June 30, 2025 and the audited consolidated financial statements for the years ended December 31, 2024 and 2023, 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 six months ended June 30, 2025 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").

The operating results attributable to the Company's Saskatchewan and United States operations have been classified and presented as discontinued operations, with all other operating results presented as continuing operations. The prior period results have been presented to conform with current period presentation. See Note 4 - "Discontinued Operations" of the condensed consolidated interim financial statements for the three and six months ended June 30, 2025 for additional information.

This MD&A includes references to certain financial measures which are not specified, defined, or determined under IFRS® Accounting Standards 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 19, 2024, Vermilion released the 2025 capital budget and associated production guidance. On March 5, 2025, the Company updated the 2025 capital budget and associated production guidance following the close of the acquisition of Westbrick Energy Ltd. ("Westbrick"), with incremental capital expenditures and production from the acquired assets reflected in guidance for the remainder of the year. On June 5, 2025, the Company provided updated guidance reflecting the removal of all remaining E&D capital associated with the Saskatchewan and United States assets following the announcement of the sale of these assets. Current capital and production guidance incorporates the July 2025 close of these sales transactions. The Company’s guidance for 2025 is as follows:

Category	2025 Prior[1]	2025 Current[1]
Production (boe/d)	125,000 - 130,000	117,000 - 122,000
E&D capital expenditures ($MM)	$730 - 760	$630 - 660
Royalty rate (% of sales)	9 - 11%	8 - 10%
Operating ($/boe)	$13.50 - 14.50	$13.00 - 14.00
Transportation ($/boe)	$3.00 - 3.50	$3.00 - 3.50
General and administration ($/boe)[2]	$2.25 - 2.75	$2.25 - 2.75
Cash taxes (% of pre-tax FFO)	6 - 10%	4 - 8%
Asset retirement obligations settled ($MM)	$60	$60
Payments on lease obligations ($MM)	$20	$15

(1) Current 2025 guidance reflects foreign exchange assumptions of CAD/USD 1.40, CAD/EUR 1.56, and CAD/AUD 0.89. Prior 2025 guidance reflects foreign exchange assumptions of CAD/USD 1.43, CAD/EUR 1.51, and CAD/AUD 0.90.

(2) General and administration expense inclusive of expected cash-settled equity based compensation.

Consolidated Results Overview

	Q2 2025	Q2 2024	Q2/25 vs. Q2/24	YTD 2025	YTD 2024	2025 vs. 2024
Production [1]						
Crude oil and condensate (bbls/d)	**37,449**	32,879	14%	**34,933**	32,787	7%
NGLs (bbls/d)	**12,656**	7,196	76%	**10,921**	7,121	53%
Natural gas (mmcf/d)	**515.38**	269.39	91%	**442.78**	271.99	63%
Total (boe/d)	**136,002**	84,974	60%	**119,649**	85,240	40%
Build (draw) in inventory (mbbls)	**156**	66		**219**	(161)	
Financial metrics						
Fund flows from continuing operations ($M) [2]	**225,316**	173,154	30%	**436,087**	559,345	(22)%
Fund flows from discontinued operations ($M) [2][7]	**34,362**	63,549	(46)%	**79,620**	108,716	(27)%
Fund flows from operations ($M) [2]	**259,678**	236,703	10%	**515,707**	668,061	(23)%
Fund flows from operations per share	**1.68**	1.48	14%	**3.35**	4.16	(20)%
Net earnings (loss) from continuing operations	**74,385**	(108,807)	N/A	**78,088**	(117,438)	N/A
Net (loss) earnings from discontinued operations [7]	**(307,843)**	26,382	N/A	**(296,593)**	37,318	N/A
Net loss ($M)	**(233,458)**	(82,425)	183%	**(218,505)**	(80,120)	173%
Net earnings (loss) per share - continuing operations	**0.48**	(0.68)	N/A	**0.51**	(0.73)	N/A
Net (loss) earnings per share - discontinued operations [7]	**(1.99)**	0.17	N/A	**(1.92)**	0.23	N/A
Net loss per share	**(1.51)**	(0.52)	190%	**(1.42)**	(0.50)	184%
Cash flows from operating activities ($M)	**140,467**	266,322	(47)%	**420,851**	620,617	(32)%
Free cash flow ($M) [3]	**144,189**	126,093	14%	**218,099**	367,009	(41)%
Long-term debt ($M)	**1,951,250**	915,364	113%	**1,951,250**	915,364	113%
Net debt ($M) [4]	**1,413,321**	906,715	56%	**1,413,321**	906,715	56%
Cash dividends ($/share)	**0.13**	0.12	8%	**0.26**	0.24	8%
Activity						
Capital expenditures ($M) [5]	**115,489**	110,610	4%	**297,608**	301,052	(1)%
Acquisitions ($M) [6]	**1,591**	5,450	(71)%	**1,122,589**	15,202	7,285%

(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 loss and net loss per share, respectively. The measures do not have a standardized meaning under IFRS Accounting Standards and therefore may not be comparable to similar measures presented by other issuers. FFO is comprised of sales less royalties, transportation, operating, general and administrative (G&A), corporate income tax, PRRT, 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. Fund flows from continuing operations and fund flows from discontinued operations are calculated in the same manner as FFO and are most directly comparable to net earnings (loss) from continuing operations and net earnings (loss) discontinued operations, respectively.

(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 Accounting Standards 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.

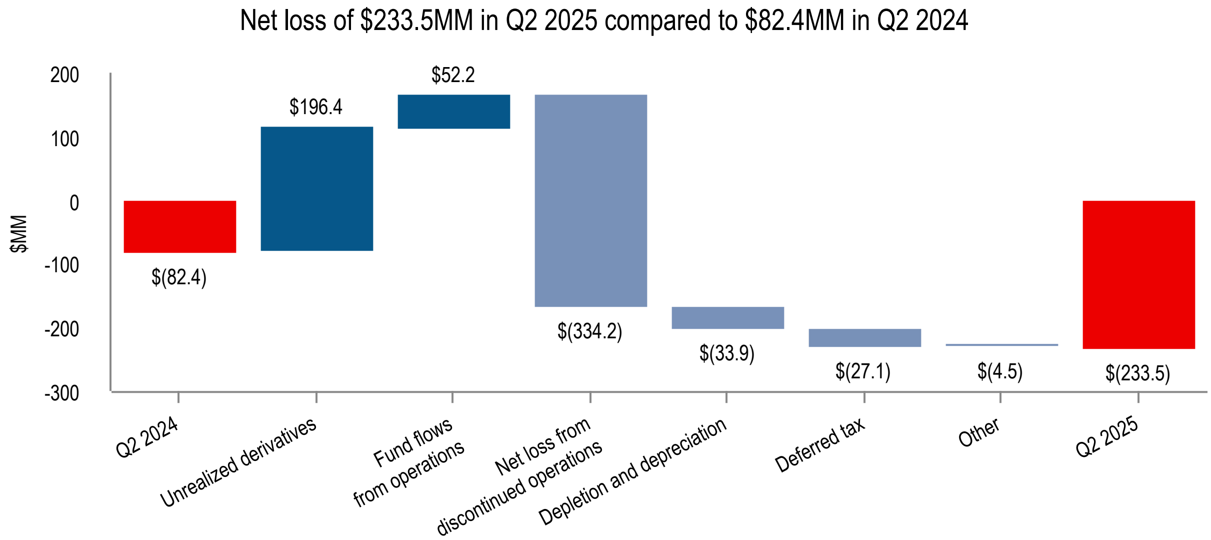
(5) Capital expenditures is a non-GAAP financial measure that does not have a standardized meaning under IFRS Accounting Standards and therefore may not be comparable to similar measures presented by other issuers. The measure is calculated as the sum of drilling and development costs and exploration 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 Accounting Standards 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.

(7) Refer to the "North America" section of this MD&A for additional information on discontinued operations as a result of assets held for sale as at June 30, 2025.

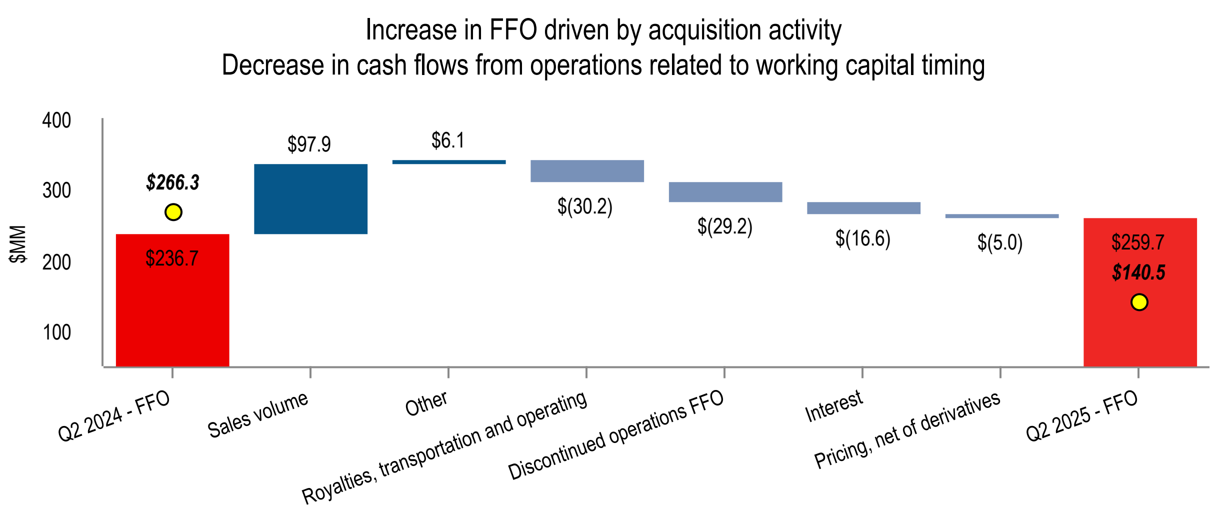
Financial performance review

Q2 2025 vs. Q2 2024



"Other" contains equity based compensation, accretion, unrealized foreign exchange and unrealized other.
"Discontinued operations" contains net loss from the United States and Saskatchewan disposal groups.
All other items presented above are attributable to continuing operations.

- We recorded a net loss of $233.5 million ($1.51/basic share) for Q2 2025 compared to $82.4 million ($0.52/basic share) in Q2 2024. The change in net loss was primarily due to impairment of $372.4 million recorded on the United States and Saskatchewan assets held for sale, after agreements were reached to divest in the assets in Q2 2025 and closed in July 2025. This was partially offset by favourable changes in our mark-to-market derivative position primarily on our European natural gas contracts and increased FFO on higher production from the Westbrick assets acquired in Q1 2025.

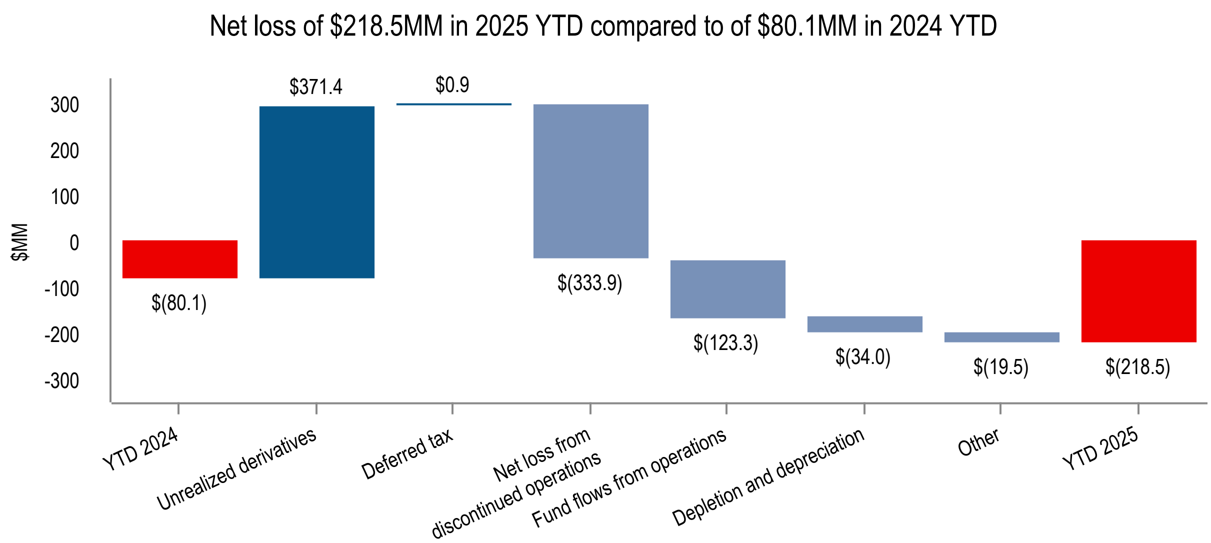


"Sales volume" is the sum of sales volume variance from continuing operations.
"Pricing, net of derivatives" is the sum of pricing variance received on sales volumes from continuing operations, net of realized derivatives.
"Other" contains G&A, cash-settled equity based compensation, taxes, realized FX and other realized expense.
"Discontinued operations" contains fund flows from the United States and Saskatchewan operations.
All other items reconciling FFO are attributable to continuing operations.

Cash flows from operating activities

- Cash flows from operating activities were $140.5 million in Q2 2025 compared to $266.3 million in Q2 2024, while fund flows from operations increased to $259.7 million in Q2 2025 from $236.7 million in Q2 2024. The increase in FFO was primarily driven by higher net operating income from the Westbrick acquisition and new wells coming on production. The increase was partially offset by higher interest attributable to the Westbrick acquisition as proceeds from dispositions will not impact interest expense until Q3 2025. The decrease in fund flows from discontinued operations was mainly driven by lower liquids pricing and lower sales volumes. Variances between cash flows from operating activities and fund flows from operations are primarily driven by working capital timing differences, including lower tax liabilities at the end of Q2 2025.

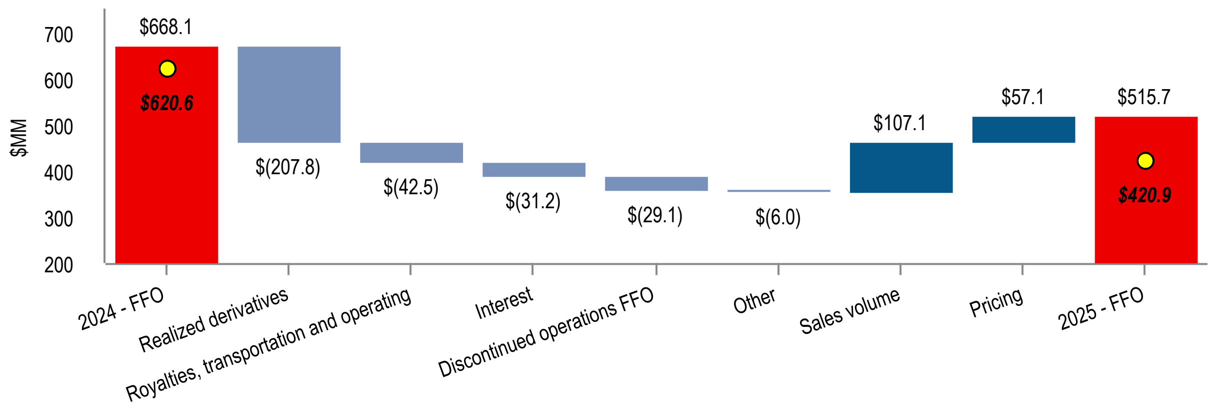
Q2 2025 YTD vs. Q2 2024 YTD



"Other" contains equity based compensation, accretion, unrealized foreign exchange, and unrealized other.
"Net loss from discontinued operations" contains net loss from the United States and Saskatchewan disposal groups.
All other items presented above are attributable to continuing operations.

- For the six months ended June 30, 2025, we recorded a net loss of $218.5 million compared to $80.1 million for the comparable period in 2024. The increase in net loss was primarily attributable to impairment taken on assets held for sale and lower fund flows from operations driven by lower realized gains on derivative contracts. The increase was partially offset by favourable changes in our mark-to-market derivative position, primarily on our European natural gas contracts.

FFO decreased on lower realized derivative gains, offset by strong Westbrick netbacks.
Cash flows from operating activities decreased on timing of working capital.



"Sales volume" is the sum of sales volume variance from continuing operations.
"Pricing, net of derivatives" is the sum of pricing variance received on sales volumes from continuing operations, net of realized derivatives.
"Other" contains G&A, cash-settled EBC, taxes, realized FX and realized other expense.
"Discontinued operations FFO" contains fund flows from United States and Saskatchewan operations.
All other items reconciling FFO are attributable to continuing operations.

Cash flows from operating activities

- For the six months ended June 30, 2025 as compared to the same period in 2024, cash flows from operating activities decreased by $199.8 million to $420.9 million and FFO decreased by $152.4 million to $515.7 million. The decrease in FFO was primarily driven by lower realized gains on derivative contracts of $207.8 million, and higher interest expense on Q1 refinancing activities. This was partially offset by increased net operating income from Westbrick, and higher realized pricing on legacy natural gas assets. Variances between cash flows from operating activities and fund flows from operations are primarily driven by working capital timing differences.

Production review

Q2 2025 vs. Q2 2024

- Consolidated average production increased to 136,002 boe/d in Q2 2025 compared to Q2 2024 production of 84,974 boe/d. Production increased as a result of the Westbrick acquisition which closed at the end of February 2025, combined with increased production in Germany and Central and Eastern Europe. The increases were partially offset by natural well decline in Ireland and the United States.

Activity review

For the three months ended June 30, 2025, capital expenditures were $115.5 million.

- In our North America core region, we invested capital expenditures of $58.0 million, comprised of $50.6 million of capital expenditure in Canada and $7.5 million in the United States:
    - Vermilion completed five (5.0 net) and brought on production eleven (11.0 net) Montney liquids-rich shale gas wells;
    - In the Deep Basin, the Company drilled four (3.4 net), completed three (2.4 net), and brought on production three (2.4 net) liquids-rich conventional natural gas wells;
    - In the United States, four (1.4 net) non-operated light and medium crude oil wells were brought on production;
    - Vermilion did not have an active operated drilling program in Saskatchewan or the United States as these assets were marketed for sale, and definitive agreements to sell both assets were announced in Q2 2025.

- In our International core region, capital expenditures of $57.5 million were invested:
    - In Germany, we invested $18.1 million as we continued to invest in our deep gas drilling program, drilled, completed and brought on production two (2.0 net) light and medium crude oil wells, and invested in our surface facilities;
    - In the Netherlands, we invested $13.9 million on the strategic gas field interconnector project and workovers;

- In France, we invested $10.2 million primarily on subsurface maintenance in the Aquitaine and Paris basins, as well as tank and pipeline inspections and workovers;
- In Australia, $8.8 million was invested primarily on facilities activities and workovers;
- In Central and Eastern Europe, $5.7 million was invested as we drilled, completed and brought on production one (1.0 net) conventional natural gas well on the SA-10 block;
- In Ireland, $0.8 million was invested on facilities.

Financial sustainability review

Free cash flow

- Free cash flow decreased by $148.9 million to $218.1 million for the six months ended June 30, 2025 compared to the prior year period primarily due to lower fund flows from operations driven by lower realized gains on derivative contracts and higher interest expense, partially offset by higher sales impacted by the acquisition of Westbrick.

Long-term debt and net debt

- Long-term debt increased to $2.0 billion as at June 30, 2025 (December 31, 2024 - $1.0 billion) due to the Westbrick acquisition, including the issuance of the $563.0 million (US $400.0 million) 2033 senior unsecured notes, the issuance of the $450.0 million term loan, and draws on the revolving credit facility. The increase was partially offset by the repayment of the $399.5 million (US $300.0 million) 2025 senior unsecured notes, a $200.0 million repayment of the term loan in Q2 2025, and the foreign exchange impact of the US dollar weakening against the Canadian dollar on our US denominated senior unsecured notes. Subsequent to June 30, 2025, proceeds from dispositions were used to repay debt, including extinguishing the remaining balance of the term loan.
- As at June 30, 2025, net debt was $1.4 billion, or $0.4 billion higher compared to December 31, 2024 due to the financing of the Westbrick acquisition in Q1 2025. Net debt decreased from $2.1 billion at March 31, 2025 as a result of strong free cash flow generation from higher sales volumes and expected proceeds from dispositions on assets held for sale, partially driven by the Westbrick acquisition.
- The ratio of net debt to four quarter trailing fund flows from operations(1) increased to 1.4 as at June 30, 2025 (December 31, 2024 - 0.8) primarily due to higher net debt as a result of the Westbrick acquisition, partially offset by the inclusion of Westbrick's four quarter trailing fund flows from operations.

(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 Accounting Standards 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. Subsequent to February 26, 2025, net debt to four quarter trailing fund flows from operations is calculated inclusive of Westbrick Energy's pre-acquisition four quarter trailing fund flows from operations, as if the acquisition of Westbrick Energy occurred at the beginning of the four-quarter trailing period, and exclusive of the four quarter trailing fund flows from discontinued operations from assets held for sale to reflect the Company’s ability to repay debt on a pro forma basis.

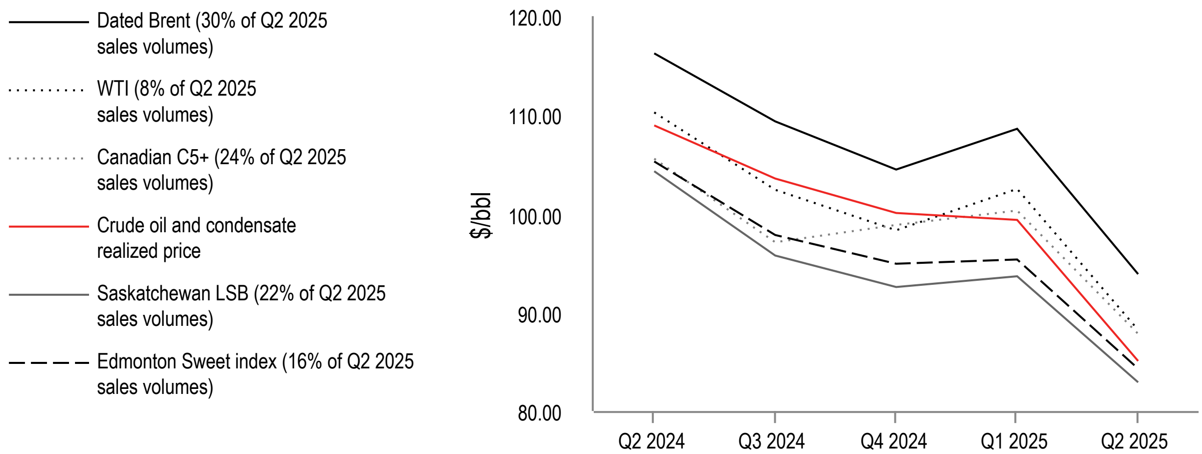
Benchmark Commodity Prices

	Q2 2025	Q2 2024	Q2/25 vs. Q2/24	YTD 2025	YTD 2024	2025 vs. 2024
Natural gas						
North America						
AECO 5A ($/mcf)	**1.69**	1.18	43%	**1.93**	1.84	5%
AECO 7A ($/mcf)	**2.07**	1.44	44%	**2.05**	1.74	18%
Henry Hub ($/mcf)	**4.76**	2.59	84%	**5.00**	2.81	78%
Henry Hub (US $/mcf)	**3.44**	1.89	82%	**3.55**	2.07	71%
Europe(1)						
NBP Day Ahead ($/mmbtu)	**15.59**	13.16	18%	**18.39**	12.47	47%
NBP Month Ahead ($/mmbtu)	**16.68**	12.50	33%	**19.08**	12.74	50%
NBP Day Ahead (€/mmbtu)	**9.93**	8.93	11%	**11.93**	8.49	41%
NBP Month Ahead (€/mmbtu)	**10.63**	8.48	25%	**12.38**	8.67	43%
TTF Day Ahead ($/mmbtu)	**16.27**	13.62	19%	**18.59**	12.69	46%
TTF Month Ahead ($/mmbtu)	**17.14**	12.61	36%	**19.20**	12.85	49%
TTF Day Ahead (€/mmbtu)	**10.36**	9.24	12%	**12.07**	8.64	40%
TTF Month Ahead (€/mmbtu)	**10.92**	8.56	28%	**12.46**	8.75	42%
Crude oil						
WTI ($/bbl)	**88.22**	110.25	(20)%	**95.25**	107.00	(11)%
WTI (US $/bbl)	**63.74**	80.57	(21)%	**67.58**	78.76	(14)%
Edmonton Sweet index ($/bbl)	**84.29**	105.28	(20)%	**89.74**	98.66	(9)%
Edmonton Sweet index (US $/bbl)	**60.90**	76.94	(21)%	**63.67**	72.62	(12)%
Saskatchewan LSB index ($/bbl)	**82.91**	104.29	(21)%	**88.19**	96.88	(9)%
Saskatchewan LSB index (US $/bbl)	**59.90**	76.21	(21)%	**62.57**	71.31	(12)%
Canadian C5+ Condensate index ($/bbl)	**87.82**	105.56	(17)%	**93.96**	101.84	(8)%
Canadian C5+ Condensate index (US $/bbl)	**63.45**	77.14	(18)%	**66.67**	74.96	(11)%
Dated Brent ($/bbl)	**93.87**	116.23	(19)%	**101.11**	114.24	(11)%
Dated Brent (US $/bbl)	**67.82**	84.94	(20)%	**71.74**	84.09	(15)%
Average exchange rates						
CDN $/US $	**1.38**	1.37	1%	**1.41**	1.36	4%
CDN $/Euro	**1.57**	1.47	7%	**1.54**	1.47	5%
Realized prices						
Crude oil and condensate ($/bbl)	**85.07**	108.93	(22)%	**91.75**	106.49	(14)%
NGLs ($/bbl)	**24.68**	31.61	(22)%	**27.55**	32.87	(16)%
Natural gas ($/mcf)	**4.88**	5.69	(14)%	**6.09**	5.90	3%
Total ($/boe)	**43.71**	62.46	(30)%	**51.45**	62.97	(18)%

(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.

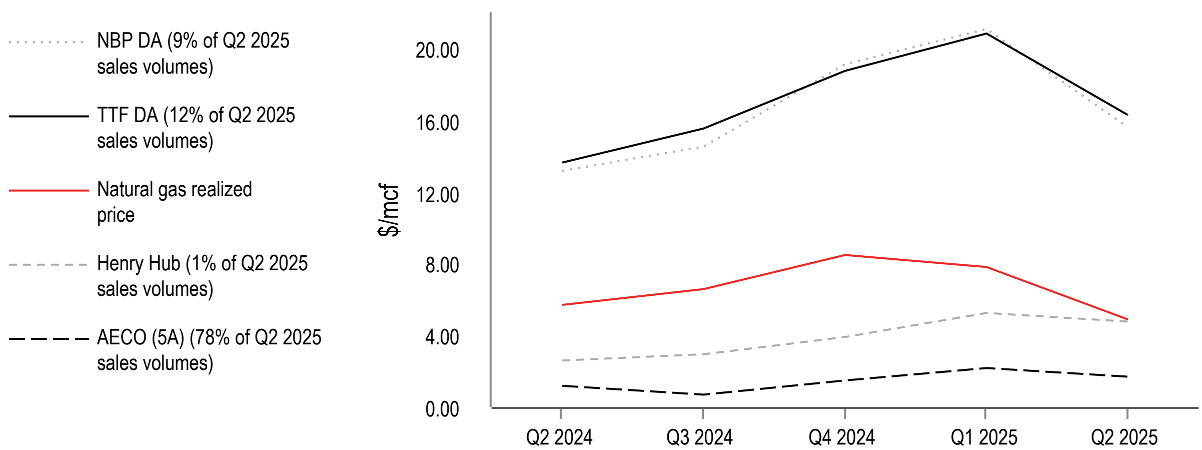
As an internationally diversified producer, we are exposed to a range of commodity prices. In our North America core region, our crude oil is sold at benchmarks linked to WTI (including the Edmonton Sweet index, the Saskatchewan LSB index, and the Canadian C5+ index) and our natural gas is sold at benchmarks 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.

Q2 2025 realized crude oil and condensate price was a $0.78/bbl premium to Edmonton Sweet Index



- Crude oil prices decreased in Q2 2025 relative to Q2 2024 on heightened macroeconomic uncertainty from tariff announcements and risk to global GDP growth. Canadian dollar WTI decreased by 20% and Dated Brent decreased by 19% in Q2 2025 relative to Q2 2024.
- In Canadian dollar terms, year-over-year, the Edmonton Sweet differential tightened by $1.02/bbl to a discount of $4.97/bbl against WTI, and the Saskatchewan LSB differential tightened by $0.63/bbl to a discount of $5.33/bbl against WTI.
- Approximately 30% of Vermilion's Q2 2025 crude oil and condensate production was priced at the Dated Brent index, which averaged a premium to WTI of US$4.08/bbl, while the remainder of our crude oil and condensate production was priced at the Saskatchewan LSB, Canadian C5+, Edmonton Sweet, and WTI indices.

Q2 2025 realized natural gas price was a $3.19/mcf premium to AECO 5A



- In Canadian dollar terms, year-over-year, prices for European natural gas at NBP and TTF increased by 18% and 19% respectively on a day ahead basis. On a month ahead basis, NBP and TTF increased by 33% and 36% respectively. Prices increased in response to higher demand coming from the global LNG market, termination of Russian gas exports to Europe through Ukraine as of January 1, 2025, and below average storage levels due to a colder winter leading to high withdrawals.
- Year-over-year natural gas prices in Canadian dollar terms at NYMEX HH increased by 84% and AECO 7A increased by 44%. AECO prices increased due to strong withdrawals in the Q1 2025 winter timeframe, whereas NYMEX HH performed relatively better due to stronger US natural gas demand and LNG demand growth starting in the first half of 2025.
- For Q2 2025, average European natural gas prices represented a $14.73/mcf premium to AECO 5A. Approximately 21% of our natural gas production in Q2 2025 benefited from this premium European pricing (Q2 2025 - 38%). The change in price exposure resulted in a decrease to our realized natural gas price in Q2 2025 compared to the same period in 2024.

North America

During the second quarter of 2025, Vermilion entered into agreements to dispose of the Company's non-core assets in Saskatchewan and the United States. As a result of these agreements, the operating results for these assets held for sale have been presented as discontinued operations throughout this MD&A in accordance with IFRS 5 "Non-current Assets Held for Sale and Discontinued Operations". Please refer to Note 4 "Discontinued operations" and Note 14 "Subsequent events" of the condensed consolidated interim financial statements for the three and six months ended June 30, 2025 for additional information. As a result, the North America continuing operations consists of our Deep Basin and Mica Montney assets.

	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Production [1]				
Crude oil and condensate (bbls/d)	**14,178**	7,883	**12,054**	7,475
NGLs (bbls/d)	**11,072**	5,374	**9,393**	5,287
Natural gas (mmcf/d)	**394.07**	148.37	**321.94**	144.65
Production from continuing operations (boe/d)	**90,926**	37,987	**75,103**	36,870
Production from discontinued operations (boe/d)	**15,453**	17,000	**15,057**	17,103
Total production volume (boe/d)	**106,379**	54,987	**90,160**	53,973

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

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**212,369**	**25.67**	105,762	30.60	**378,633**	**27.85**	206,650	30.80
Royalties	**(16,322)**	**(1.97)**	(9,767)	(2.83)	**(34,979)**	**(2.57)**	(20,880)	(3.11)
Transportation	**(22,899)**	**(2.77)**	(10,627)	(3.07)	**(39,194)**	**(2.88)**	(18,664)	(2.78)
Operating	**(62,460)**	**(7.55)**	(41,421)	(11.98)	**(105,401)**	**(7.75)**	(75,223)	(11.21)
General and administration [1]	**(11,709)**	**(1.42)**	(6,414)	(1.86)	**(29,397)**	**(2.16)**	(8,351)	(1.24)
Corporate income tax recovery (expense) [1]	**(2,325)**	**(0.28)**	4,105	1.19	**(2,760)**	**(0.20)**	966	0.14
Fund flows from continuing operations	**96,654**	**11.68**	41,638	12.05	**166,902**	**12.29**	84,498	12.60
Drilling and development	**(45,211)**		(43,594)		**(165,363)**		(161,447)	
Free cash flow from continuing operations	**51,443**		(1,956)		**1,539**		(76,949)	

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

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**90,314**	**64.23**	126,288	81.63	**190,467**	**69.89**	238,656	76.67
Royalties	**(16,800)**	**(11.95)**	(24,886)	(16.09)	**(35,999)**	**(13.21)**	(47,653)	(15.31)
Transportation	**(2,999)**	**(2.13)**	(3,497)	(2.26)	**(5,944)**	**(2.18)**	(6,793)	(2.18)
Operating	**(25,819)**	**(18.36)**	(28,065)	(18.14)	**(53,698)**	**(19.70)**	(62,935)	(20.22)
General and administration	**(10,334)**	**(7.35)**	(6,275)	(4.06)	**(15,206)**	**(5.58)**	(12,540)	(4.03)
Corporate income taxes	**—**	**—**	(16)	(0.01)	**—**	**—**	(19)	(0.01)
Fund flows from discontinued operations	**34,362**	**24.44**	63,549	41.07	**79,620**	**29.22**	108,716	34.92
Drilling and development	**(12,830)**		(17,926)		**(23,488)**		(36,582)	
Free cash flow from discontinued operations	**21,532**		45,623		**56,132**		72,134	

Production from Vermilion's North American operations averaged 106,379 boe/d in Q2 2025, an increase of 44% from the previous quarter primarily due to a full quarter of contribution from the acquired Westbrick assets following the close of the transaction in February 2025, as well as new production brought online in the Montney in the quarter.

In Q2 2025, Vermilion completed five (5.0 net) and brought on production eleven (11.0 net) Montney liquids-rich shale gas wells. In the Deep Basin, the Company drilled four (3.4 net), completed three (2.4 net), and brought on production three (2.4 net) liquids-rich conventional natural gas wells. Vermilion did not have an active drilling program in Saskatchewan or the United States as these assets were marketed for sale, and definitive agreements to sell both assets were announced in Q2 2025. In the United States, four (1.4 net) non-operated light and medium crude oil wells were brought on production.

Sales

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Canada	**212,369**	**25.67**	105,762	30.60	**378,633**	**27.85**	206,650	30.80
Discontinued operations:								
Canada	**64,766**	**66.51**	83,873	84.12	**138,901**	**72.00**	158,030	78.22
United States	**25,548**	**59.07**	42,415	77.12	**51,566**	**64.78**	80,626	73.80
Total discontinued operations	**90,314**	**64.23**	126,288	81.63	**190,467**	**69.89**	238,656	76.67
North America	**302,683**	**31.27**	232,050	46.37	**569,100**	**34.87**	445,306	45.33

Sales in North America increased for the three and six months ended June 30, 2025 compared to the prior year primarily due to increased production in Alberta from the Westbrick acquisition, and in British Columbia with fifteen Mica Montney wells brought online in 2024 and twelve in the first six months of 2025, partially offset by decreased production in the United States due to lower capital allocation. Sales decreased on a per boe basis for the three months ended June 30, 2025 primarily on decreased North American crude pricing. Sales decreased for the six months ended June 30, 2025 primarily on lower United States sales volumes coupled with decreased North American crude pricing.

Royalties

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$boe	$M	$boe
Canada	**(16,322)**	**(1.97)**	(9,767)	(2.77)	**(34,979)**	**(2.57)**	(20,880)	(3.07)
Discontinued operations:								
Canada	**(9,664)**	**(9.92)**	(12,399)	(12.44)	**(21,596)**	**(11.19)**	(23,841)	(11.80)
United States	**(7,136)**	**(16.50)**	(12,487)	(22.70)	**(14,403)**	**(18.09)**	(23,812)	(21.79)
Total discontinued operations	**(16,800)**	**(11.95)**	(24,886)	(16.09)	**(35,999)**	**(13.21)**	(47,653)	(15.31)
North America	**(33,122)**	**(3.42)**	(34,653)	(6.93)	**(70,978)**	**(4.35)**	(68,533)	(6.98)
Royalty rate (% of sales)								
Canada	**7.7 %**		9.2 %		**9.2 %**		10.1 %	
Discontinued operations	**18.6 %**		19.7 %		**18.9 %**		20.0 %	

Royalties in North America remained fairly flat on a dollar basis for the three and six months ended June 30, 2025 compared to the same periods in the prior year primarily due to decreased United States crude production and lower realized liquids pricing. The decrease was partially offset by royalties on production from the Westbrick acquisition in Q1 2025 and sliding scale price decreases. Royalties decreased on a per unit basis for the three and six months ended June 30, 2025 primarily due to lower realized crude prices and the higher gas weighting in our production mix following the Westbrick acquisition, subject to lower royalty rates relative to liquids.

Transportation

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$boe	$M	$boe
Canada	**(22,899)**	**(2.77)**	(10,627)	(3.02)	**(39,194)**	**(2.88)**	(18,664)	(2.74)
Discontinued operations:								
Canada	**(2,805)**	**(2.88)**	(2,946)	(2.95)	**(5,625)**	**(2.92)**	(5,863)	(2.90)
United States	**(194)**	**(0.45)**	(551)	(1.00)	**(319)**	**(0.40)**	(930)	(0.85)
Total discontinued operations	**(2,999)**	**(2.13)**	(3,497)	(2.26)	**(5,944)**	**(2.18)**	(6,793)	(2.18)
North America	**(25,898)**	**(2.68)**	(14,124)	(2.82)	**(45,138)**	**(2.77)**	(25,457)	(2.59)

Transportation expense in North America increased on a dollar basis for the three and six months ended June 30, 2025 compared to the prior year comparable periods primarily due to transportation costs on acquired Westbrick assets. On a per boe basis, transportation expense decreased for the three months ended June 30, 2025, primarily due to lower per unit costs on acquired production and increased for the six months ended June 30, 2025 primarily due to higher pipeline fees in British Columbia.

Operating expense

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Canada	**(62,460)**	**(7.55)**	(41,421)	(11.77)	**(105,401)**	**(7.75)**	(75,223)	(11.06)
Discontinued operations:								
Canada	**(19,254)**	**(19.77)**	(21,719)	(21.78)	**(40,191)**	**(20.83)**	(48,375)	(23.95)
United States	**(6,565)**	**(15.18)**	(6,346)	(11.54)	**(13,507)**	**(16.97)**	(14,560)	(13.33)
Total discontinued operations	**(25,819)**	**(18.36)**	(28,065)	(18.14)	**(53,698)**	**(19.70)**	(62,935)	(20.22)
North America	**(88,279)**	**(9.12)**	(69,486)	(13.89)	**(159,099)**	**(9.75)**	(138,158)	(14.06)

Operating expense in North America increased on a dollar basis for the three and six months ended June 30, 2025 compared to the prior year comparable period primarily due to the Westbrick acquisition, partially offset by lower downhole maintenance, lower trucking costs in British Columbia and lower wages and facility maintenance in Saskatchewan. Operating expense decreased on a per boe basis for the three and six months ended June 30, 2025, primarily due to lower per unit operating costs on increased production impacted by the Westbrick acquisition and new wells coming on stream.

International

	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Production [(1)]				
Crude oil and condensate (bbls/d)	**12,055**	12,714	**11,945**	13,087
Natural gas (mmcf/d)	**105.39**	103.64	**105.26**	109.08
Total production volume (boe/d)	**29,623**	29,987	**29,489**	31,267
Total sales volume (boe/d)	**27,911**	29,271	**28,286**	32,149

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

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$boe	$M	$boe
Sales	**231,465**	**91.13**	246,875	92.68	**533,894**	**104.28**	541,654	92.57
Royalties	**(12,946)**	**(5.10)**	(11,957)	(4.49)	**(24,380)**	**(4.76)**	(26,630)	(4.55)
Transportation	**(10,713)**	**(4.22)**	(11,193)	(4.20)	**(22,659)**	**(4.43)**	(22,822)	(3.90)
Operating	**(60,546)**	**(23.84)**	(70,744)	(26.56)	**(131,503)**	**(25.69)**	(151,383)	(25.87)
General and administration	**(12,228)**	**(4.81)**	(13,848)	(5.20)	**(24,328)**	**(4.75)**	(29,349)	(5.02)
Corporate income tax expense	**(8,791)**	**(3.46)**	(16,185)	(6.08)	**(27,415)**	**(5.35)**	(38,685)	(6.61)
PRRT	**(755)**	**(0.30)**	(3,638)	(1.37)	**(3,773)**	**(0.74)**	(14,421)	(2.46)
Fund flows from operations	**125,486**	**49.40**	119,310	44.78	**299,836**	**58.56**	258,364	44.16
Drilling and development	**(53,197)**		(47,830)		**(89,851)**		(93,619)	
Exploration and evaluation	**(4,251)**		(1,260)		**(18,906)**		(9,404)	
Free cash flow	**68,038**		70,220		**191,079**		155,341	

Production from Vermilion's International operations averaged 29,623 boe/d in Q2 2025, an increase of 1% from the previous quarter due to new production in Germany and Croatia, partially offset by natural declines.

In Germany, Vermilion drilled, completed and brought on production two (2.0 net) light and medium crude oil wells. The Osterheide well (1.0 net) that was brought on production at the end of Q1 2025 produced approximately 1,100 boe/d in Q2 2025, driven by strong local demand. In Croatia, the Company drilled, completed and brought on production one (1.0 net) conventional natural gas well on the SA-10 block, which began producing through the existing facility in May 2025.

Sales

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$boe	$M	$boe
Australia	**20,853**	**108.85**	32,787	131.06	**51,685**	**117.62**	107,613	131.08
France	**54,481**	**85.94**	83,656	112.22	**115,543**	**94.53**	172,652	112.75
Netherlands	**28,188**	**82.74**	30,541	74.19	**71,074**	**101.18**	65,507	73.01
Germany	**44,804**	**89.80**	29,157	78.76	**98,139**	**100.31**	60,341	75.83
Ireland	**67,794**	**93.60**	69,793	79.76	**168,780**	**111.18**	134,257	74.99
Central and Eastern Europe	**15,345**	**101.95**	941	85.04	**28,673**	**110.59**	1,284	83.42
International	**231,465**	**91.13**	246,875	92.68	**533,894**	**104.28**	541,654	92.57

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)	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Australia	**2,105**	2,749	**2,428**	4,511
France	**6,966**	8,192	**6,753**	8,414
Germany	**1,235**	1,000	**1,526**	932
International	**10,306**	11,941	**10,707**	13,857

Sales decreased on a dollar and per boe basis for the three months ended June 30, 2025 compared to the prior year primarily due to the timing of inventory combined with slightly lower realized oil prices. For the six months ended June 30, 2025, sales decreased on a dollar basis and increased on a per boe basis compared to the prior year primarily due to the timing of inventory and downtime partially offset by higher realized sales prices on our European natural gas.

Royalties

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$boe	$M	$boe
France	**(8,858)**	**(13.97)**	(10,283)	(13.79)	**(16,324)**	**(13.35)**	(23,335)	(15.24)
Netherlands	**—**	**—**	—	—	**(10)**	**(0.01)**	(217)	(0.24)
Germany	**(1,991)**	**(3.99)**	(1,435)	(3.88)	**(4,329)**	**(4.42)**	(2,790)	(3.51)
Central and Eastern Europe	**(2,097)**	**(13.93)**	(239)	(21.60)	**(3,717)**	**(14.34)**	(288)	(18.71)
International	**(12,946)**	**(5.10)**	(11,957)	(4.49)	**(24,380)**	**(4.76)**	(26,630)	(4.55)
Royalty rate (% of sales)	**5.6 %**		4.8 %		**4.6 %**		4.9 %	

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 on a per boe basis increased for the three months and six months ended June 30, 2025, primarily due to higher sales volumes in Croatia, which carried higher associated royalty rates. Royalties increased on a dollar basis for the three months ended June 30, 2025 primarily due to higher production volumes in Croatia, partially offset by lower sales volumes in France. For the six months ended June 30, 2025, royalties decreased on a dollar basis primarily due to lower sales volumes in France, partially offset by higher sales volumes in Croatia and Germany.

Transportation

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$boe	$M	$boe
France	**(5,982)**	**(9.44)**	(6,401)	(8.59)	**(11,460)**	**(9.38)**	(11,764)	(7.68)
Germany	**(2,440)**	**(4.89)**	(2,386)	(6.45)	**(6,709)**	**(6.86)**	(5,578)	(7.01)
Ireland	**(2,291)**	**(3.16)**	(2,406)	(2.75)	**(4,490)**	**(2.96)**	(5,480)	(3.06)
International	**(10,713)**	**(4.22)**	(11,193)	(4.20)	**(22,659)**	**(4.43)**	(22,822)	(3.90)

Transportation expense for the three and six months ended June 30, 2025 remained relatively flat on a dollar basis compared to the prior year. On a per boe basis, transportation expense increased for the six months ended June 30, 2025 compared to the prior year primarily due to higher vessel costs in France.

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

Operating expense

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$boe	$M	$boe
Australia	**(10,208)**	**(53.29)**	(14,174)	(56.66)	**(25,193)**	**(57.33)**	(40,960)	(49.89)
France	**(17,091)**	**(26.96)**	(14,606)	(19.59)	**(33,134)**	**(27.11)**	(36,046)	(23.54)
Netherlands	**(7,927)**	**(23.27)**	(10,709)	(26.01)	**(17,535)**	**(24.96)**	(21,319)	(23.76)
Germany	**(10,609)**	**(21.26)**	(14,430)	(38.98)	**(25,786)**	**(26.36)**	(25,191)	(31.66)
Ireland	**(13,576)**	**(18.74)**	(16,453)	(18.80)	**(27,818)**	**(18.32)**	(27,057)	(15.11)
Central and Eastern Europe	**(1,135)**	**(7.54)**	(372)	(33.62)	**(2,037)**	**(7.86)**	(810)	(52.62)
International	**(60,546)**	**(23.84)**	(70,744)	(26.56)	**(131,503)**	**(25.69)**	(151,383)	(25.87)

Operating expenses decreased on a dollar and per unit basis for the three months ended June 30, 2025, primarily due to a prior period gas processing fee recovery in Germany and lower sales volumes in Australia which has higher per unit costs. For the six months ended June 30, 2025, operating expenses decreased primarily due to lower sales volumes in Australia, higher gas gathering in the Netherlands and the timing of sales in France. On a per boe basis, operating expenses remained relatively flat for the six months ended June 30, 2025 compared to the prior year due to lower sales volumes in Australia and France, partially offset by fixed charges in Central and Eastern Europe and Germany.

Consolidated Financial Performance Review

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**443,834**	**41.04**	352,637	57.62	**912,527**	**48.76**	748,304	59.57
Royalties	**(29,268)**	**(2.71)**	(21,724)	(3.55)	**(59,359)**	**(3.17)**	(47,510)	(3.78)
Transportation	**(33,612)**	**(3.11)**	(21,820)	(3.57)	**(61,853)**	**(3.31)**	(41,486)	(3.30)
Operating	**(123,006)**	**(11.37)**	(112,165)	(18.33)	**(236,904)**	**(12.66)**	(226,606)	(18.04)
General and administration	**(23,937)**	**(2.21)**	(20,262)	(3.31)	**(53,725)**	**(2.87)**	(37,700)	(3.00)
Corporate income tax expense	**(11,116)**	**(1.03)**	(12,080)	(1.97)	**(30,175)**	**(1.61)**	(37,719)	(3.00)
Petroleum resource rent tax	**(755)**	**(0.07)**	(3,638)	(0.59)	**(3,773)**	**(0.20)**	(14,421)	(1.15)
Interest expense	**(37,691)**	**(3.49)**	(21,062)	(3.44)	**(70,670)**	**(3.78)**	(39,454)	(3.14)
Equity based compensation	**(5,692)**	**(0.53)**	(14,361)	(2.35)	**(5,692)**	**(0.30)**	(14,361)	(1.14)
Realized gain on derivatives	**47,699**	**4.41**	46,017	7.52	**58,818**	**3.14**	266,632	21.23
Realized foreign exchange (loss) gain	**(487)**	**(0.05)**	2,267	0.37	**2,012**	**0.11**	4,138	0.33
Realized other expense	**(653)**	**(0.06)**	(655)	(0.11)	**(15,119)**	**(0.81)**	(472)	(0.04)
Fund flows from continuing operations	**225,316**	**20.82**	173,154	28.29	**436,087**	**23.30**	559,345	44.54
Equity based compensation	**(1,286)**		3,860		**(7,217)**		(1,658)	
Unrealized gain (loss) on derivative instruments [1]	**70,569**		(125,789)		**56,894**		(314,533)	
Unrealized foreign exchange gain (loss) [1]	**6,002**		2,344		**(30,012)**		(18,863)	
Accretion	**(17,716)**		(16,146)		**(33,517)**		(32,050)	
Depletion and depreciation	**(165,761)**		(131,826)		**(314,044)**		(280,003)	
Deferred tax expense	**(41,345)**		(14,196)		**(28,390)**		(29,331)	
Unrealized other expense [1]	**(1,394)**		(208)		**(1,713)**		(345)	
Net earnings (loss) from continuing operations	**74,385**		(108,807)		**78,088**		(117,438)	

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**90,314**	**64.23**	126,288	81.63	**190,467**	**69.89**	238,656	76.67
Royalties	**(16,800)**	**(11.95)**	(24,886)	(16.09)	**(35,999)**	**(13.21)**	(47,653)	(15.31)
Transportation	**(2,999)**	**(2.13)**	(3,497)	(2.26)	**(5,944)**	**(2.18)**	(6,793)	(2.18)
Operating	**(25,819)**	**(18.36)**	(28,065)	(18.14)	**(53,698)**	**(19.70)**	(62,935)	(20.22)
General and administration	**(10,334)**	**(7.35)**	(6,275)	(4.06)	**(15,206)**	**(5.58)**	(12,540)	(4.03)
Corporate income tax expense	**—**	**—**	(16)	(0.01)	**—**	**—**	(19)	(0.01)
Fund flows from discontinued operations	**34,362**	**24.44**	63,549	41.07	**79,620**	**29.22**	108,716	34.92
Unrealized loss on derivative instruments [1]	**(11,047)**		—		**(11,047)**		—	
Unrealized foreign exchange (loss) gain [1]	**(552)**		725		**(437)**		291	
Accretion	**(2,156)**		(2,063)		**(4,235)**		(4,093)	
Depletion and depreciation	**(18,406)**		(29,358)		**(46,511)**		(59,615)	
Deferred tax recovery (expense)	**62,342**		(6,471)		**58,403**		(7,981)	
Impairment expense	**(372,386)**		—		**(372,386)**		—	
Net (loss) earnings from discontinued operations	**(307,843)**		26,382		**(296,593)**		37,318	
Fund flows from operations	**259,678**	**21.25**	236,703	30.87	**515,707**	**24.03**	668,061	42.61
Net loss	**(233,458)**		(82,425)		**(218,505)**		(80,120)	

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

Fluctuations in fund flows from operations, including fund flows from continuing operations and fund flows from discontinued 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

- For the three months ended June 30, 2025, general and administration expense increased compared to the same period in the prior year due to restructuring costs incurred in Canada and higher short-term incentive plan payments. General and administration expense increased for the six months ended June 30, 2025 compared to the comparable period in 2024 primarily due to transaction costs related to the Westbrick acquisition and restructuring costs in Canada.

Equity based compensation

- Equity based compensation included within funds flow from operations primarily relates to the settlement of withholding taxes on long-term incentives granted to directors, officers, and employees under security-based arrangements via cash, which were previously settled through the issuance and sale of shares from Treasury. Equity based compensation settled in cash decreased for the three and six months ended June 30, 2025 compared to the same periods in the prior year primarily due to the higher value of LTIP in the prior year.

PRRT and corporate income taxes

- PRRT for the three and six months ended June 30, 2025 declined compared to the same periods in the prior year due to lower sales in Australia.
- Corporate income taxes for the three and six months ended June 30, 2025 decreased compared to the prior year comparable periods due to lower revenues from the European business unit.

Interest expense

- Interest expense for the three and six months ended June 30, 2025 increased due to higher debt levels driven by the issuance of the 2033 senior notes for US $400.0 million, the $450.0 million term loan, and draws on revolving credit facility. The increase was partially offset by the repayment of the US $300.0 million 2025 senior notes and the partial repayment of the term loan of $200.0 million.

Realized gain or loss on derivatives

- For the three and six months ended June 30, 2025, 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 June 30, 2025 is included in “Supplemental Table 2” of this MD&A.

Realized other income or expense

- Realized other expense for the three months ended June 30, 2025 remained relatively flat compared to the prior year. For the six months ended June 30, 2025, realized other expense increased primarily related to an estimated provision recognized to satisfy work commitments.

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 included within net earnings (loss) and excluded from funds flow from operations relates to non-cash compensation expense attributable to long-term incentives granted to directors, officers, and employees under security-based arrangements. Equity based compensation expense decreased for the three and six months ended June 30, 2025 versus the prior year primarily due to the cash settlement of previously share-based settled expenses at a higher value of LTIP in the prior year, and the lower value of LTIP awards outstanding 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.

USD-to-CAD cross currency interest rate swaps and foreign exchange swaps may be entered into to manage the foreign exchange movements on USD borrowings on our revolving credit facility. As such, unrealized gains and losses on our cross currency interest swaps are offset by unrealized losses and gains on foreign exchange relating to the underlying USD borrowings from our revolving credit facility.

For the three months ended June 30, 2025, we recognized a net unrealized gain on derivative instruments of $59.5 million. This consists of unrealized gains of $42.0 million on our European natural gas commodity derivative instruments, $34.4 million on our North American gas commodity derivative instruments and $4.6 million on our USD-to-CAD foreign exchange swaps, partially offset by losses of $14.5 million on our Cross Currency Interest Rate Swaps, $6.4 million on our equity swaps, and $0.6 million on our crude oil and liquids commodity derivative instruments.

For the six months ended June 30, 2025, we recognized a net unrealized gain on derivative instruments of $56.9 million. This consists of unrealized gains of $92.4 million on our European natural gas commodity derivative instruments and $6.1 million on our USD-to-CAD foreign exchange swaps, partially offset by an unrealized loss of $19.3 million on our North American gas commodity derivative instruments, $15.6 million on our Cross Currency Interest Rate Swaps, $13.4 million on our equity swaps and $4.4 million on our crude oil and liquids commodity derivative instruments.

A net unrealized loss on derivative instruments of $11.0 million was recorded for the three and six months ended June 30, 2025 relating to WTI swaps entered into by Vermilion on behalf of the purchaser of the Saskatchewan assets held for sale and were novated upon closing. These contracts are presented as liabilities held for sale at their fair value within discontinued operations and began maturing after June 30, 2025. The swaps have an average strike price of CAD $80/bbl with daily volume of 3,175 to 4,540 from Q3 2025 to Q2 2028.

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 2025, unrealized foreign exchange gains and losses primarily resulted from:

- The translation of Euro and US dollar denominated intercompany loans to and 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 Accounting Standards, 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 loss reflects only the parent company's side of the translation.
- The translation of our USD denominated 2030 senior unsecured notes and USD denominated 2033 senior unsecured notes.
- The translation of USD borrowings on our revolving credit facility. The unrealized foreign exchange gains or losses on these borrowings are offset by unrealized derivative gains or losses on associated USD-to-CAD cross currency interest rate swaps.

For the three months ended June 30, 2025, we recognized a net unrealized foreign exchange gain of $5.5 million, primarily driven by the effects of the US dollar weakening 5.1% against the Canadian dollar on our US denominated debt, partially offset by the effects of the Euro strengthening 3.2% against the Canadian dollar on our Euro denominated loans. For the six months ended June 30, 2025, we recognized a net unrealized foreign exchange loss of $30.0 million, primarily driven by the effects of the Euro strengthening 7.3% against the Canadian dollar on our Euro denominated loans, partially offset by the impact of the US dollar weakening 5.2% against the Canadian dollar on our US denominated debt.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. For the three and six months ended June 30, 2025, accretion remained relatively flat compared to the prior year comparable periods.

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 six months ended June 30, 2025 of $15.07 and $16.82 decreased from $21.02 and $21.67 in the same periods of the prior year primarily due to the increase in reserves acquired from the Westbrick assets. The decrease was partially offset by related increases to future development costs and the strengthening of the Euro against the Canadian dollar.

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 six months ended June 30, 2025, the Company recorded a net deferred tax recovery on continuing and discontinued operations compared to deferred tax expense in the same periods of 2024. The net deferred tax recovery in the current year was driven by the impairment recorded in Canada attributable to discontinued operations, and was partially offset by loss utilization on taxable income in Canada and Ireland. The deferred tax expense in the prior year was primarily driven by the derecognition of the deferred tax assets in Ireland.

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 June 30, 2025, we have a ratio of net debt to four quarter trailing fund flows from operations of 1.4.

Net debt

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

	As at	
($M)	**Jun 30, 2025**	**Dec 31, 2024**
Long-term debt	**1,951,250**	963,456
Adjusted working capital [1]	**(540,502)**	3,426
Unrealized FX on swapped USD borrowings	**2,573**	—
Net debt	**1,413,321**	966,882
Ratio of net debt to four quarter trailing fund flows from operations [2]	**1.4**	0.8

(1) Adjusted working capital is a non-GAAP financial measure that is not standardized under IFRS Accounting Standards 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. These figures include amounts for assets held for sale and liabilities associated with assets held for sale which represent the estimated cash proceeds from dispositions that closed subsequent to June 30, 2025.

(2) Subsequent to February 26, 2025, net debt to four quarter trailing fund flows from operations is calculated inclusive of Westbrick Energy's pre-acquisition four quarter trailing fund flows from operations, as if the acquisition of Westbrick Energy occurred at the beginning of the four-quarter trailing period, and exclusive of the four quarter trailing fund flows from discontinued operations from assets held for sale to reflect the Company's ability to repay debt on a pro forma basis.

As at June 30, 2025, net debt increased to $1.4 billion (December 31, 2024 - $1.0 billion) due to the financing of the Westbrick acquisition in Q1 2025, which was partially offset by the disposition of the Saskatchewan and United States assets held for sale at June 30, 2025 and strong free cash flow generation from higher sales volumes, partially driven by the Westbrick acquisition and new wells brought on stream.

The ratio of net debt to four quarter trailing fund flows from operations as at June 30, 2025 increased to 1.4 (December 31, 2024 - 0.8) primarily due to higher net debt as a result of the Westbrick acquisition, partially offset by the inclusion of Westbrick's four quarter trailing fund flows from operations and strong free cash flow generation.

Long-term debt

The balances recognized on our balance sheet are as follows:

	As at	
	Jun 30, 2025	Dec 31, 2024
Revolving credit facility	**632,341**	—
Term loan	**245,756**	—
2025 senior unsecured notes	**—**	398,275
2030 senior unsecured notes	**536,642**	565,181
2033 senior unsecured notes	**536,511**	—
Long-term debt	**1,951,250**	963,456

Revolving credit facility

As at June 30, 2025, Vermilion had in place a bank revolving credit facility maturing May 25, 2029 with terms and outstanding positions as follows:

	As at	
($M)	Jun 30, 2025	Dec 31, 2024
Total facility amount	**1,350,000**	1,350,000
Amount drawn	**(632,341)**	—
Letters of credit outstanding	**(32,173)**	(22,731)
Unutilized capacity	**685,486**	1,327,269

The facility is secured by various fixed and floating charges against the subsidiaries of Vermilion. As at June 30, 2025, $632.3 million of the revolving credit facility was drawn.

On June 9, 2025, the maturity date of the syndicate facility was extended to May 25, 2029 (previously May 26, 2028). The total facility amount of $1.35 billion and aggregate amount available under the facility of $1.8 billion remain unchanged.

As at June 30, 2025, the revolving credit facility was subject to the following financial covenants:

		As at	
Financial covenant	Limit	Jun 30, 2025	Dec 31, 2024
Consolidated total debt to consolidated EBITDA	Less than 4.0	**1.45**	0.72
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	**0.65**	—
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	**11.57**	16.59

Our financial covenants include financial measures defined within our revolving credit facility agreement that are not defined under IFRS Accounting Standards. 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 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.

As at June 30, 2025 and December 31, 2024, Vermilion was in compliance with the above covenants.

Term Loan

Concurrent with the completion of the Westbrick acquisition on February 26, 2025, Vermilion's credit facility agreement was amended to incorporate a new $450.0 million term loan (the “Term Loan”) which was immediately drawn. The Term Loan does not require principal repayments prior to its May 26, 2028 maturity, is non-revolving, and is subject to the same financial covenants as Vermilion’s revolving credit facility. The Term Loan bears interest based on a reference rate plus an applicable margin.

During the second quarter of 2025, $200.0 million of the term loan was repaid. Subsequent to June 30, 2025, the term loan was repaid in full using proceeds from the sale of the Saskatchewan assets.

2025 senior unsecured notes

On March 13, 2017, Vermilion issued US $300.0 million of senior unsecured notes at par. The notes bore interest at a rate of 5.625% per annum and were paid semi-annually on March 15 and September 15. The notes matured on March 15, 2025 and the balance was repaid in full.

2030 senior unsecured notes

On April 26, 2022, Vermilion closed a private offering of US $400.0 million of senior unsecured notes, priced at 99.241% of par. The notes bear interest at a rate of 6.875% per annum, to be paid semi-annually on May 1 and November 1. The notes mature on May 1, 2030. As direct senior unsecured obligations of Vermilion, the notes rank equally with existing and future senior unsecured indebtedness of the Company.

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

- 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 %

2033 senior unsecured notes

On February 11, 2025 Vermilion closed a private offering of US $400.0 million of senior unsecured notes at par. The notes bear interest at a rate of 7.250% per annum, to be paid semi-annually on February 15 and August 15. The notes mature on February 15, 2033. As direct senior unsecured obligations of Vermilion, the notes rank equally with existing and future senior unsecured indebtedness of the Company.

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 February 15, 2028, Vermilion may redeem up to 40% 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 107.250% of the principal amount of the notes, together with accrued and unpaid interest.
- Prior to February 15, 2028, 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 February 15, 2028, 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
2028	103.625 %
2029	101.813 %
2030 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
April 2025 onwards	Quarterly	$0.13

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Shares ('000s)	Amount ($M)
Balance at January 1	**154,344**	**3,918,898**
Shares issued for acquisition	**1,104**	**13,363**
Vesting of equity based awards	**439**	**16,091**
Share-settled dividends on vested equity based awards	**66**	**599**
Repurchase of shares	**(1,934)**	**(49,451)**
Balance at June 30	**154,019**	**3,899,500**

As at June 30, 2025, there were approximately 3.9 million equity based compensation awards outstanding. As at August 7, 2025, there were approximately 153.8 million common shares issued and outstanding.

On July 9, 2025, the Toronto Stock Exchange approved the Company's notice of intention to renew its normal course issuer bid ("the NCIB"). The NCIB renewal allows Vermilion to purchase up to 15,259,187 common shares (representing approximately 10% of outstanding common shares) beginning July 12, 2025 and ending July 11, 2026. Common shares purchased under the NCIB will be cancelled.

In the second quarter of 2025, Vermilion purchased 0.7 million common shares under the NCIB for total consideration of $6.3 million. The common shares purchased under the NCIB were cancelled.

Subsequent to June 30, 2025, Vermilion purchased and cancelled 0.2 million shares under the NCIB for total consideration of $2.6 million.

Contractual Obligations and Commitments

As at June 30, 2025, Vermilion had the following contractual obligations and commitments:

($M)	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years	Total
Long-term debt [(1)] [(2)]	123,377	492,214	1,359,824	664,414	2,639,829
Lease obligations [(3)]	27,113	35,000	30,611	44,680	137,404
Processing and transportation agreements	85,902	112,874	148,358	814,891	1,162,025
Purchase obligations	31,032	10,691	332	368	42,423
Drilling and service agreements	34,150	24,012	—	—	58,162
Total contractual obligations and commitments	**301,574**	**674,791**	**1,539,125**	**1,524,353**	**4,039,843**

(1) Includes interest on senior unsecured notes.
(2) Includes the term loan, which was repaid subsequent to June 30, 2025.
(3) Includes undiscounted IFRS 16 - *Leases* obligations of $83.8 million as at June 30, 2025, net of office subleases, surface lease rental commitments of $51.9 million and other of $1.7 million that are not considered leases under IFRS 16 and are not represented on the balance sheet.
(4) Commitments denominated in foreign currencies have been translated using the related spot rates on June 30, 2025.

Asset Retirement Obligations

As at June 30, 2025, asset retirement obligations were $0.9 billion compared to $1.2 billion as at December 31, 2024. The decrease in asset retirement obligations is primarily attributable to changes in rates combined with the reclassification of liabilities associated with the United States and Saskatchewan dispositions, partially offset by the acquisition of Westbrick asset retirement obligations and the foreign exchange impact of the Euro strengthening against the Canadian dollar. The credit spread increased to 4.4% at June 30, 2025 compared to 2.6% at December 31, 2024 primarily due to a higher 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:

	Jun 30, 2025	Dec 31, 2024	Change
Credit spread added to below noted risk-free rates	**4.4 %**	2.6 %	1.8 %
Country specific risk-free rate			
Canada	**3.6 %**	3.2 %	0.4 %
United States	**4.9 %**	4.8 %	0.1 %
France	**4.0 %**	3.7 %	0.3 %
Netherlands	**3.0 %**	2.7 %	0.3 %
Germany	**3.0 %**	2.6 %	0.4 %
Ireland	**3.1 %**	2.8 %	0.3 %
Australia	**4.4 %**	4.6 %	(0.2)%
Central and Eastern Europe	**4.8 %**	4.7 %	0.1 %

Current cost estimates are inflated to the estimated time of abandonment using inflation rates of between 1.5% and 3.6% (as at December 31, 2024 - between 1.5% and 3.6%).

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, 2024 available on SEDAR+ at www.sedarplus.ca or on Vermilion’s website at www.vermilionenergy.com.

Critical Accounting Estimates

The preparation of consolidated financial statements in accordance with IFRS Accounting Standards 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 six months ended June 30, 2025. 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, 2024, 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.

Vermilion has limited the scope of design controls and procedures ("DC&P") and internal controls over financial reporting to exclude controls, policies and procedures of Westbrick Energy Ltd., which was acquired on February 26, 2025. The scope limitation is in accordance with section 3.3(1)(b) of NI 52-109 which allows an issuer to limit the design of DC&P and ICFR to exclude controls, policies, and procedures of a business that the issuer acquired not more than 365 days before the end of the fiscal period.

The table below presents the summary financial information of Westbrick Energy Ltd. included in Vermilion's financial statements as at and for the three and six months ended June 30, 2025:

($M)	Balance at June 30, 2025
Non-current assets	1,252,737
Non-current liabilities	(190,427)
Net assets	1,062,310

($M)	Q2 2025	YTD 2025
Revenue	92,878	131,369
Net earnings	6,141	12,647

Recently Adopted Accounting Pronouncements

Vermilion did not adopt any new accounting pronouncements as at June 30, 2025 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 Canadian Sustainability Standards Board has released Canada-specific version of IFRS S1 and S2 as Canadian Sustainability Disclosure Standards 1 and 2. While Canadian securities regulators have not mandated these standards, they have referenced them as a useful voluntary disclosure framework for sustainability and climate-related disclosure, and noted that securities legislation already requires issuers to disclose material climate-related risks. Australia has mandated the Australian version of IFRS S2 as Australian Sustainability Reporting Standards 2 with mandatory disclosure anticipated for Vermilion in 2027. 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 issued 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 June 30, 2025, 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: Operating 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.

	Q2 2025			YTD 2025			Q2 2024	YTD 2024
	Liquids	Natural Gas	Total	Liquids	Natural Gas	Total	Total	Total
	$/bbl	$/mcf	$/boe	$/bbl	$/mcf	$/boe	$/boe	$/boe
Continuing Operations								
Canada								
Sales	57.34	2.25	**25.67**	60.77	2.45	**27.85**	30.60	30.80
Royalties	(6.12)	(0.06)	**(1.97)**	(6.87)	(0.14)	**(2.57)**	(2.83)	(3.11)
Transportation	(4.90)	(0.32)	**(2.77)**	(5.19)	(0.32)	**(2.88)**	(3.07)	(2.78)
Operating	(16.85)	(0.66)	**(7.55)**	(16.83)	(0.69)	**(7.75)**	(11.98)	(11.21)
Operating netback	29.47	1.21	**13.38**	31.88	1.30	**14.65**	12.72	13.70
General and administration			**(1.42)**			**(2.16)**	(1.86)	(1.24)
Corporate income taxes ($/boe)			**(0.28)**			**(0.20)**	1.19	0.14
Fund flows from operations ($/boe)			**11.68**			**12.29**	12.05	12.60
France								
Sales	85.94	—	**85.94**	94.53	—	**94.53**	112.22	112.75
Royalties	(13.97)	—	**(13.97)**	(13.35)	—	**(13.35)**	(13.79)	(15.24)
Transportation	(9.44)	—	**(9.44)**	(9.38)	—	**(9.38)**	(8.59)	(7.68)
Operating	(26.96)	—	**(26.96)**	(27.11)	—	**(27.11)**	(19.59)	(23.54)
Operating netback	35.57	—	**35.57**	44.69	—	**44.69**	70.25	66.29
General and administration			**(4.57)**			**(5.32)**	(5.11)	(5.87)
Current income taxes			**0.64**			**(0.06)**	(7.99)	(7.69)
Fund flows from operations ($/boe)			**31.64**			**39.31**	57.15	52.73
Netherlands								
Sales	60.99	13.82	**82.74**	83.84	16.89	**101.18**	74.19	73.01
Royalties	—	—	**—**	—	—	**(0.01)**	—	(0.24)
Operating	(25.10)	(3.88)	**(23.27)**	(28.11)	(4.16)	**(24.96)**	(26.01)	(23.76)
Operating netback	35.89	9.94	**59.47**	55.73	12.73	**76.21**	48.18	49.01
General and administration			**(4.49)**			**(4.06)**	(4.31)	(4.14)
Current income taxes			**(7.31)**			**(19.68)**	(19.09)	(21.03)
Fund flows from operations ($/boe)			**47.67**			**52.47**	24.78	23.84
Germany								
Sales	88.45	15.03	**89.80**	97.64	16.89	**100.31**	78.76	75.83
Royalties	(3.26)	(0.70)	**(3.99)**	(2.86)	(0.84)	**(4.42)**	(3.88)	(3.51)
Transportation	(11.82)	(0.48)	**(4.89)**	(15.22)	(0.59)	**(6.86)**	(6.45)	(7.01)
Operating	(20.77)	(3.57)	**(21.26)**	(25.21)	(4.47)	**(26.36)**	(38.98)	(31.66)
Operating netback	52.60	10.28	**59.66**	54.35	10.99	**62.67**	29.45	33.65
General and administration			**(7.42)**			**(6.93)**	(8.27)	(7.08)
Current income taxes			**(8.28)**			**(10.49)**	(4.60)	(7.64)
Fund flows from operations ($/boe)			**43.96**			**45.25**	16.58	18.93
Ireland								
Sales	—	15.60	**93.60**	—	18.52	**111.18**	79.76	74.99
Transportation	—	(0.53)	**(3.16)**	—	(0.49)	**(2.96)**	(2.75)	(3.06)
Operating	—	(3.12)	**(18.74)**	—	(3.05)	**(18.32)**	(18.80)	(15.11)
Operating netback	—	11.95	**71.70**	—	14.98	**89.90**	58.21	56.82
General and administration			**(1.75)**			**(1.94)**	(1.67)	(2.03)
Current income taxes			**(0.43)**			**(0.33)**	(0.36)	(0.43)
Fund flows from operations ($/boe)			**69.52**			**87.63**	56.18	54.36

	Q2 2025 Liquids $/bbl	Q2 2025 Natural Gas $/mcf	Q2 2025 Total $/boe	YTD 2025 Liquids $/bbl	YTD 2025 Natural Gas $/mcf	YTD 2025 Total $/boe	Q2 2024 Total $/boe	YTD 2024 Total $/boe
Australia								
Sales	108.85	—	**108.85**	117.62	—	**117.62**	131.06	131.08
Operating	(53.29)	—	**(53.29)**	(57.33)	—	**(57.33)**	(56.66)	(49.89)
PRRT (1)	(3.94)	—	**(3.94)**	(8.59)	—	**(8.59)**	(14.54)	(17.57)
Operating netback	51.62	—	**51.62**	51.70	—	**51.70**	59.86	63.62
General and administration			**(8.75)**			**(6.52)**	(8.01)	(4.56)
Current income taxes			**(2.16)**			**(1.27)**	(1.40)	(1.45)
Fund flows from operations ($/boe)			**40.71**			**43.91**	50.45	57.61
Central and Eastern Europe								
Sales	46.82	17.01	**101.95**	63.74	18.45	**110.59**	85.04	83.42
Royalties	(3.34)	(2.33)	**(13.93)**	(2.20)	(2.39)	**(14.34)**	(21.60)	(18.71)
Operating	—	(1.26)	**(7.54)**	—	(1.31)	**(7.86)**	(33.62)	(52.62)
Operating netback	43.48	13.42	**80.48**	61.54	14.75	**88.39**	29.82	12.09
General and administration			**(7.65)**			**(9.15)**	(156.98)	(235.90)
Current income taxes			**(12.30)**			**(8.46)**	—	—
Fund flows from operations ($/boe)			**60.53**			**70.78**	(127.16)	(223.81)
Discontinued Operations								
United States								
Sales	71.40	1.85	**59.07**	77.83	3.09	**64.78**	77.12	73.80
Royalties	(19.92)	(0.54)	**(16.50)**	(21.73)	(0.87)	**(18.09)**	(22.70)	(21.79)
Transportation	(0.56)	—	**(0.45)**	(0.51)	—	**(0.40)**	(1.00)	(0.85)
Operating	(18.32)	(0.50)	**(15.18)**	(20.45)	(0.77)	**(16.97)**	(11.54)	(13.33)
Operating netback	32.60	0.81	**26.94**	35.14	1.45	**29.32**	41.88	37.83
General and administration			**(5.36)**			**(5.27)**	(5.95)	(5.99)
Fund flows from operations ($/boe)			**21.58**			**24.05**	35.93	31.84
Canada - Saskatchewan								
Sales	77.11	1.62	**66.51**	82.93	1.89	**72.00**	84.12	78.22
Royalties	(11.48)	(0.27)	**(9.92)**	(14.50)	1.19	**(11.19)**	(12.44)	(11.80)
Transportation	(3.12)	(0.26)	**(2.88)**	(3.15)	(0.27)	**(2.92)**	(2.95)	(2.90)
Operating	(22.99)	(0.42)	**(19.77)**	(24.10)	(0.45)	**(20.83)**	(21.78)	(23.95)
Operating netback	39.52	0.67	**33.94**	41.18	2.36	**37.06**	46.95	39.57
General and administration			**(8.23)**			**(5.71)**	(3.01)	(2.97)
Fund flows from operations ($/boe)			**25.71**			**31.35**	43.94	36.60
Total Company								
Sales	69.28	4.88	**43.71**	76.05	6.09	**51.45**	62.46	62.97
Realized hedging gain	5.08	0.54	**3.90**	2.96	0.44	**2.74**	6.00	17.01
Royalties	(8.97)	(0.14)	**(3.77)**	(10.02)	(0.18)	**(4.45)**	(6.08)	(6.07)
Transportation	(4.91)	(0.32)	**(3.00)**	(5.17)	(0.33)	**(3.16)**	(3.30)	(3.08)
Operating	(19.26)	(1.36)	**(12.18)**	(20.14)	(1.60)	**(13.55)**	(18.29)	(18.47)
PRRT (2)	(0.17)	—	**(0.06)**	(0.47)	—	**(0.18)**	(0.47)	(0.92)
Operating netback	41.05	3.60	**28.60**	43.21	4.42	**32.85**	40.32	51.44
General and administration			**(2.80)**			**(3.22)**	(3.46)	(3.21)
Interest expense			**(3.08)**			**(3.30)**	(2.75)	(2.52)
Equity based compensation			**(0.47)**			**(0.27)**	(1.87)	(0.92)
Realized foreign exchange (loss) gain			**(0.04)**			**0.09**	0.30	0.26
Other expense			**(0.05)**			**(0.71)**	(0.09)	(0.03)
Corporate income taxes			**(0.91)**			**(1.41)**	(1.58)	(2.41)
Fund flows from operations ($/boe)			**21.25**			**24.03**	30.87	42.61

(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 June 30, 2025:

	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
AECO												
Q3 2025	mcf	CAD	42,652	2.04	42,652	3.09	—	—	127,955	2.77	—	—
Q4 2025	mcf	CAD	44,223	2.64	44,223	3.72	—	—	98,104	3.17	—	—
Q1 2026	mcf	CAD	45,021	2.93	45,021	4.02	—	—	120,847	3.38	—	—
Q2 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	132,694	3.30	—	—
Q3 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	132,694	3.30	—	—
Q4 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	107,557	3.33	—	—
Q1 2027	mcf	CAD	—	—	—	—	—	—	99,521	3.16	—	—
Q2 2027	mcf	CAD	—	—	—	—	—	—	90,043	3.13	—	—
Q3 2027	mcf	CAD	—	—	—	—	—	—	90,043	3.13	—	—
Q4 2027	mcf	CAD	—	—	—	—	—	—	90,043	3.13	—	—
AECO Basis (AECO less NYMEX Henry Hub)												
Q3 2025	mcf	USD	—	—	—	—	—	—	10,000	(1.15)	—	—
Q4 2025	mcf	USD	—	—	—	—	—	—	10,000	(1.15)	—	—
NYMEX Henry Hub												
Q3 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	10,000	3.19	—	—
Q4 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	10,000	3.19	—	—
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	—	—	—	—	—	—
Q1 2027	mcf	USD	—	—	—	—	—	—	24,000	3.76	—	—
Q2 2027	mcf	USD	—	—	—	—	—	—	24,000	3.76	—	—
Q3 2027	mcf	USD	—	—	—	—	—	—	24,000	3.76	—	—
Q4 2027	mcf	USD	—	—	—	—	—	—	24,000	3.76	—	—
Q1 2028	mcf	USD	—	—	9,538	6.50	—	—	6,813	6.00	—	—
Q2 2028	mcf	USD	—	—	14,000	6.50	—	—	10,000	6.00	—	—
Q3 2028	mcf	USD	—	—	14,000	6.50	—	—	10,000	6.00	—	—
Q4 2028	mcf	USD	—	—	14,000	6.50	—	—	10,000	6.00	—	—
TTF												
Q3 2025	mcf	EUR	22,111	8.31	22,111	12.88	22,111	4.01	27,024	12.81	—	—
Q4 2025	mcf	EUR	31,938	8.05	31,938	12.50	31,938	3.67	23,339	11.78	—	—
Q1 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	23,339	11.78	—	—
Q2 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	20,882	9.77	—	—
Q3 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	20,882	9.77	—	—
Q4 2026	mcf	EUR	28,253	7.43	28,253	11.66	28,253	2.93	7,370	9.35	—	—
Q1 2027	mcf	EUR	28,253	7.43	28,253	11.66	28,253	2.93	9,827	9.87	—	—
Q2 2027	mcf	EUR	—	—	—	—	—	—	2,457	11.43	—	—
Q3 2027	mcf	EUR	—	—	—	—	—	—	2,457	11.43	—	—
Q4 2027	mcf	EUR	—	—	—	—	—	—	2,457	11.43	—	—
Buy TTF, Sell NBP Basis												
Q3 2025	mcf	EUR	—	—	—	—	—	—	23,885	(0.47)	—	—
THE												
Q3 2025	mcf	EUR	—	—	—	—	—	—	2,457	14.95	—	—

	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
Dated Brent												
Q3 2025	bbl	USD	—	—	—	—	—	—	2,500	74.34	—	—
WTI												
Q3 2025	bbl	USD	8,750	63.02	8,750	68.14	8,750	55.02	5,500	70.49	256	57.98
Q4 2025	bbl	USD	15,000	60.41	15,000	68.30	15,000	49.83	—	—	256	57.98
Q1 2026	bbl	USD	10,000	60.10	10,000	68.02	10,000	48.05	—	—	500	62.27
Q2 2026	bbl	USD	7,500	62.97	7,500	70.92	7,500	50.00	—	—	500	62.27
Q3 2026	bbl	USD	7,500	62.97	7,500	70.92	7,500	50.00	—	—	—	—
Q4 2026	bbl	USD	7,500	62.97	7,500	70.92	7,500	50.00	—	—	—	—
MSW-WTI Differential												
Q3 2025	bbl	USD	—	—	—	—	—	—	1,000	(3.45)	—	—
C5-WTI Differential												
Q3 2025	bbl	USD	—	—	—	—	—	—	2,000	(0.60)	—	—
Conway												
Q3 2025	bbl	USD	—	—	—	—	—	—	2,500	32.23	—	—
Q4 2025	bbl	USD	—	—	—	—	—	—	2,000	32.42	—	—
Q1 2026	bbl	USD	—	—	—	—	—	—	1,000	31.13	—	—
Q2 2026	bbl	USD	—	—	—	—	—	—	1,000	31.13	—	—

(1) This table is exclusive of WTI swaps entered into by Vermilion on behalf of the purchaser of the Saskatchewan assets held for sale and were novated upon closing. These contracts are presented as liabilities held for sale at their fair value within discontinued operations and began maturing after June 30, 2025. The swaps have an average strike price of CAD $80/bbl with daily volume of 3,175 to 4,540 from Q3 2025 to Q2 2028.

VET Equity Swaps		Initial Share Price		Share Volume
Swap	Jan 2020 - Apr 2027	20.9788	CAD	2,250,000
Swap	Jan 2020 - Jul 2027	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
Collar	Sell USD, Buy CAD	Jul 2025 - Dec 2025	12,500,000	USD	1.3637	12,500,000	USD	1.4133	—	—

Cross Currency Interest Rate		Receive Notional Amount		Receive Rate	Pay Notional Amount		Pay Rate
Swap	Feb 2033	250,000,000	USD	7.250%	357,870,000	CAD	6.099%
Swap	June 2025 - July 2025	438,447,400	USD	SOFR + 2.350%	600,000,000	CAD	CORRA + 2.218

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											
Oct 2025 - Dec 2025	bbl	USD	30-Sep-2025	—	—	—	—	—	—	3,000	65.00
Jan 2026 - Jun 2026	bbl	USD	31-Dec-2025	—	—	—	—	—	—	2,000	65.00
Jan 2026 - Dec 2026	bbl	USD	31-Dec-2025	—	—	—	—	—	—	1,000	65.00
Jul 2026 - Dec 2026	bbl	USD	30-Jun-2026	—	—	—	—	—	—	1,000	70.00
TTF											
Jan 2026 - Dec 2026	mcf	EUR	31-Dec-2025	—	—	—	—	—	—	4,913	13.19
Jan 2027 - Dec 2027	mcf	EUR	30-Jun-2026	—	—	—	—	—	—	2,457	10.26
Jan 2027 - Dec 2027	mcf	EUR	31-Dec-2026	—	—	—	—	—	—	4,913	10.26

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Drilling and development	**111,238**	109,350	**278,702**	291,648
Exploration and evaluation	**4,251**	1,260	**18,906**	9,404
Capital expenditures	**115,489**	110,610	**297,608**	301,052

Acquisitions ($M)	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Acquisitions, net of cash acquired	**1,591**	5,450	**1,086,047**	5,829
Shares issued for acquisition	**—**	—	**13,363**	—
Acquisition of securities	**—**	—	**—**	9,373
Acquired working capital deficit	**—**	—	**23,179**	—
Acquisitions	**1,591**	5,450	**1,122,589**	15,202

By category ($M)	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Drilling, completion, new well equip and tie-in, workovers and recompletions	**74,185**	39,436	**191,881**	177,497
Production equipment and facilities	**37,960**	62,648	**93,260**	111,129
Seismic, studies, land and other	**3,344**	8,526	**12,467**	12,426
Capital expenditures	**115,489**	110,610	**297,608**	301,052
Acquisitions	**1,591**	5,450	**1,122,589**	15,202
Total capital expenditures and acquisitions	**117,080**	116,060	**1,420,197**	316,254

Capital expenditures by country ($M)	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Canada	**45,211**	43,594	**165,363**	161,447
France	**10,246**	11,389	**17,002**	22,404
Netherlands	**13,873**	4,033	**21,620**	8,631
Germany	**18,087**	21,897	**43,322**	45,925
Ireland	**817**	356	**1,145**	3,449
Australia	**8,755**	8,809	**18,457**	14,980
Central and Eastern Europe	**5,670**	2,606	**7,211**	7,634
Capital expenditures on continuing operations	**102,659**	92,684	**274,120**	264,470
Canada	**5,374**	15,613	**10,865**	22,042
United States	**7,456**	2,313	**12,623**	14,540
Capital expenditures on discontinued operations	**12,830**	17,926	**23,488**	36,582
Capital expenditures	**115,489**	110,610	**297,608**	301,052

Acquisitions by country ($M)	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Canada	**1,591**	5,450	**1,122,589**	15,202
Acquisitions	**1,591**	5,450	**1,122,589**	15,202

Supplemental Table 4: Production

	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22
Continuing Operations												
Canada												
Light and medium crude oil (bbls/d)	**5,812**	4,136	4,102	4,844	4,288	3,252	3,294	3,572	869	2,768	3,201	2,821
Condensate [(1)] (bbls/d)	**8,366**	5,768	3,546	3,338	3,595	3,815	3,696	4,046	3,194	4,459	4,087	3,847
Other NGLs [(1)] (bbls/d)	**11,072**	7,695	4,980	5,715	5,374	5,200	5,390	5,333	4,215	5,871	5,190	5,786
NGLs (bbls/d)	**19,438**	13,463	8,526	9,053	8,969	9,015	9,086	9,379	7,409	10,330	9,277	9,633
Conventional natural gas (mmcf/d)	**394.06**	249.02	151.64	148.37	148.37	140.93	148.20	150.97	141.80	148.30	133.77	130.57
Total (boe/d)	**90,926**	59,104	37,898	38,625	37,987	35,753	37,081	38,113	31,912	37,813	34,772	34,212
France												
Light and medium crude oil (bbls/d)	**6,827**	6,810	7,083	7,115	7,246	7,308	7,395	7,578	7,788	7,578	7,247	6,818
Total (boe/d)	**6,827**	6,810	7,083	7,115	7,246	7,308	7,395	7,578	7,788	7,578	7,247	6,818
Netherlands												
Condensate [(1)] (bbls/d)	**35**	34	44	39	51	165	119	39	61	66	49	74
NGLs (bbls/d)	**35**	34	44	39	51	165	119	39	61	66	49	74
Conventional natural gas (mmcf/d)	**22.25**	23.91	24.20	25.06	26.84	31.02	32.06	24.32	27.28	29.07	27.41	29.15
Total (boe/d)	**3,744**	4,020	4,078	4,216	4,524	5,336	5,462	4,091	4,607	4,910	4,617	4,933
Germany												
Light and medium crude oil (bbls/d)	**1,731**	1,512	1,596	1,598	1,698	1,722	1,775	1,713	1,715	1,410	1,481	1,764
Conventional natural gas (mmcf/d)	**25.49**	21.05	21.71	21.41	18.41	22.87	19.62	20.29	22.05	25.85	25.86	26.54
Total (boe/d)	**5,979**	5,020	5,215	5,167	4,766	5,533	5,046	5,095	5,391	5,717	5,791	6,187
Ireland												
Conventional natural gas (mmcf/d)	**47.75**	52.92	55.32	59.06	57.70	60.34	64.04	47.96	67.51	24.58	26.04	25.74
Total (boe/d)	**7,959**	8,820	9,220	9,844	9,616	10,057	10,673	7,993	11,251	4,096	4,340	4,290
Australia												
Light and medium crude oil (bbls/d)	**3,460**	3,477	3,778	2,040	3,713	4,264	4,715	1,204	—	—	4,847	4,763
Total (boe/d)	**3,460**	3,477	3,778	2,040	3,713	4,264	4,715	1,204	—	—	4,847	4,763
Central and Eastern Europe												
Conventional natural gas (mmcf/d)	**9.90**	7.24	11.21	11.13	0.69	0.29	0.54	0.05	0.30	0.64	0.67	0.63
Total (boe/d)	**1,654**	1,208	1,869	1,855	122	48	90	8	50	107	111	104

	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22
Discontinued Operations												
United States												
Light and medium crude oil (bbls/d)	**2,977**	2,261	2,449	2,909	3,817	3,483	3,187	4,404	3,349	2,824	3,282	2,824
Condensate (1) (bbls/d)	**12**	19	34	12	27	29	27	15	22	20	36	35
Other NGLs (1) (bbls/d)	**792**	795	848	1,064	988	1,078	1,131	1,124	1,025	1,020	1,218	1,031
NGLs (bbls/d)	**804**	814	882	1,076	1,015	1,107	1,158	1,139	1,047	1,040	1,254	1,066
Conventional natural gas (mmcf/d)	**5.83**	5.78	5.88	7.08	7.27	8.23	7.49	7.25	7.23	7.14	7.45	7.03
Total (boe/d)	**4,752**	4,039	4,311	5,164	6,044	5,962	5,593	6,751	5,601	5,055	5,779	5,062
Canada - Saskatchewan												
Light and medium crude oil (bbls/d)	**7,961**	8,039	7,512	7,682	8,180	8,397	8,320	8,482	12,032	13,906	14,247	14,014
Condensate (1) (bbls/d)	**266**	328	182	260	258	260	338	364	312	260	438	357
Other NGLs (1) (bbls/d)	**792**	677	784	768	834	768	891	887	1,298	1,004	1,089	1,084
NGLs (bbls/d)	**1,058**	1,005	966	1,028	1,092	1,028	1,229	1,251	1,610	1,264	1,527	1,441
Conventional natural gas (mmcf/d)	**10.09**	9.44	9.63	8.62	10.11	10.91	11.96	12.97	17.46	12.04	13.04	14.47
Total (boe/d)	**10,701**	10,617	10,084	10,147	10,956	11,244	11,542	11,894	16,552	17,178	17,948	17,868
Consolidated												
Light and medium crude oil (bbls/d)	**28,768**	26,235	26,521	26,188	28,948	28,426	28,685	26,952	25,753	28,485	34,305	33,003
Condensate (1) (bbls/d)	**8,681**	6,151	3,806	3,649	3,931	4,269	4,180	4,463	3,589	4,805	4,610	4,312
Other NGLs (1) (bbls/d)	**12,656**	9,167	6,612	7,547	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901
NGLs (bbls/d)	**21,337**	15,318	10,418	11,196	11,127	11,315	11,592	11,807	10,127	12,701	12,107	12,213
Conventional natural gas (mmcf/d)	**515.38**	369.36	279.59	280.73	269.39	274.59	283.91	263.80	283.63	247.61	234.23	234.12
Total (boe/d)	**136,002**	103,115	83,536	84,173	84,974	85,505	87,597	82,727	83,152	82,455	85,450	84,237

	YTD 2025	2024	2023	2022	2021	2020
Continuing Operations						
Canada						
Light and medium crude oil (bbls/d)	**4,979**	4,124	558	2,713	2,136	2,809
Condensate (1) (bbls/d)	**7,075**	3,573	3,761	4,280	4,475	4,515
Other NGLs (1) (bbls/d)	**9,393**	5,317	4,981	5,772	5,857	6,150
NGLs (bbls/d)	**16,468**	8,890	8,742	10,052	10,332	10,665
Conventional natural gas (mmcf/d)	**321.94**	147.35	144.26	130.44	122.90	131.22
Total (boe/d)	**75,103**	37,570	33,344	34,505	32,951	35,345
France						
Light and medium crude oil (bbls/d)	**6,819**	7,188	7,584	7,639	8,799	8,903
Total (boe/d)	**6,819**	7,188	7,584	7,639	8,799	8,903
Netherlands						
Light and medium crude oil (bbls/d)	**—**	—	—	—	3	1
Condensate (1) (bbls/d)	**34**	75	71	66	97	88
NGLs (bbls/d)	**34**	75	71	66	97	88
Conventional natural gas (mmcf/d)	**23.08**	26.77	28.18	32.66	43.40	46.16
Total (boe/d)	**3,881**	4,536	4,768	5,510	7,334	7,782
Germany						
Light and medium crude oil (bbls/d)	**1,622**	1,653	1,654	1,435	1,044	968
Conventional natural gas (mmcf/d)	**23.28**	21.10	21.93	26.18	15.81	12.65
Total (boe/d)	**5,502**	5,170	5,310	5,798	3,679	3,076
Ireland						
Conventional natural gas (mmcf/d)	**50.32**	58.10	51.12	27.48	29.25	37.44
Total (boe/d)	**8,387**	9,683	8,520	4,579	4,875	6,240

	YTD 2025	2024	2023	2022	2021	2020
Australia						
Light and medium crude oil (bbls/d)	**3,468**	3,446	1,492	3,995	3,810	4,416
Total (boe/d)	**3,468**	3,446	1,492	3,995	3,810	4,416
Central and Eastern Europe						
Conventional natural gas (mmcf/d)	**8.58**	5.86	0.38	0.57	0.31	1.90
Total (boe/d)	**1,432**	978	63	95	51	317
Discontinued Operations						
United States						
Light and medium crude oil (bbls/d)	**2,621**	3,162	3,445	2,908	2,597	3,046
Condensate (1) (bbls/d)	**15**	25	21	34	8	5
Other NGLs (1) (bbls/d)	**794**	994	1,076	1,066	1,146	1,218
NGLs (bbls/d)	**809**	1,019	1,097	1,100	1,154	1,223
Conventional natural gas (mmcf/d)	**5.81**	7.11	7.28	7.20	6.84	7.47
Total (boe/d)	**4,398**	5,367	5,754	5,207	4,890	5,514
Canada - Saskatchewan						
Light and medium crude oil (bbls/d)	**8,000**	7,941	12,735	14,117	14,818	18,297
Condensate (1) (bbls/d)	**298**	240	405	341	356	371
Other NGLs (1) (bbls/d)	**734**	789	1,239	1,123	1,322	1,569
NGLs (bbls/d)	**1,032**	1,029	1,644	1,464	1,678	1,940
Conventional natural gas (mmcf/d)	**9.77**	9.81	16.68	13.66	15.13	20.16
Total (boe/d)	**10,659**	10,605	17,159	17,859	19,017	23,597
Consolidated						
Light and medium crude oil (bbls/d)	**27,509**	27,514	27,469	32,809	33,208	38,441
Condensate (1) (bbls/d)	**7,424**	3,913	4,258	4,721	4,936	4,980
Other NGLs (1) (bbls/d)	**10,921**	7,100	7,296	7,961	8,325	8,937
NGLs (bbls/d)	**18,345**	11,013	11,554	12,682	13,261	13,917
Conventional natural gas (mmcf/d)	**442.78**	276.10	269.83	238.18	233.64	256.99
Total (boe/d)	**119,649**	84,543	83,994	85,187	85,408	95,190

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]

	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22
Continuing operations:												
North America												
Crude oil and condensate (bbls/d)	**14,178**	9,904	7,648	8,182	7,883	7,067	6,990	7,618	4,063	7,227	7,288	6,668
NGLs (bbls/d)	**11,072**	7,695	4,980	5,715	5,374	5,200	5,390	5,333	4,215	5,871	5,190	5,786
Natural gas (mmcf/d)	**394.06**	249.02	151.64	148.37	148.37	140.93	148.20	150.97	141.80	148.30	133.77	130.57
Total (boe/d)	**90,926**	59,104	37,898	38,625	37,987	35,753	37,081	38,113	31,912	37,813	34,772	34,212
International												
Crude oil and condensate (bbls/d)	**12,055**	11,835	12,502	10,792	12,714	13,459	14,004	10,534	9,564	9,054	13,624	13,419
Natural gas (mmcf/d)	**105.39**	105.12	112.44	116.66	103.64	114.52	116.27	92.61	117.14	80.13	79.97	82.05
Total (boe/d)	**29,623**	29,355	31,243	30,237	29,987	32,546	33,381	25,969	29,087	22,408	26,953	27,095
Discontinued operations:												
North America												
Crude oil and condensate (bbls/d)	**11,216**	10,647	10,177	10,863	12,282	12,169	11,872	13,265	15,715	17,010	18,003	17,230
NGLs (bbls/d)	**1,584**	1,472	1,632	1,832	1,822	1,846	2,022	2,011	2,323	2,024	2,307	2,115
Natural gas (mmcf/d)	**15.93**	15.22	15.51	15.70	17.38	19.14	19.45	20.22	24.69	19.18	20.49	21.50
Total (boe/d)	**15,452**	14,656	14,395	15,311	17,000	17,206	17,135	18,645	22,153	22,233	23,727	22,930
Consolidated												
Crude oil and condensate (bbls/d)	**37,449**	32,386	30,327	29,837	32,879	32,695	32,866	31,416	29,341	33,290	38,915	37,315
NGLs (bbls/d)	**12,656**	9,167	6,612	7,547	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901
Natural gas (mmcf/d)	**515.38**	369.36	279.59	280.73	269.39	274.59	283.92	263.80	283.63	247.61	234.23	234.12
Total (boe/d)	**136,002**	103,115	83,536	84,173	84,974	85,505	87,597	82,727	83,152	82,455	85,450	84,237

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

Sales volumes

	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22
Continuing operations:												
North America												
Crude oil and condensate (bbls/d)	**14,178**	9,904	7,648	8,182	7,883	7,067	6,990	7,618	4,063	7,227	7,288	6,668
NGLs (bbls/d)	**11,072**	7,695	4,980	5,715	5,374	5,200	5,390	5,333	4,215	5,871	5,190	5,786
Natural gas (mmcf/d)	**394.06**	249.02	151.64	148.37	148.37	140.93	148.20	150.97	141.80	148.30	133.77	130.57
Total (boe/d)	**90,926**	59,104	37,898	38,625	37,987	35,753	37,081	38,113	31,912	37,813	34,772	34,212
International												
Crude oil and condensate (bbls/d)	**10,344**	11,145	11,360	12,580	11,998	15,938	9,221	9,950	10,302	8,087	16,257	11,493
Natural gas (mmcf/d)	**105.39**	105.12	112.44	116.66	103.64	114.52	116.27	92.61	117.14	80.13	79.97	82.05
Total (boe/d)	**27,911**	28,668	30,101	32,024	29,271	35,026	28,598	25,386	29,824	21,442	29,585	25,169
Discontinued operations:												
North America												
Crude oil and condensate (bbls/d)	**11,216**	10,647	10,177	10,863	12,282	12,169	11,872	13,265	15,715	17,010	18,003	17,230
NGLs (bbls/d)	**1,584**	1,472	1,632	1,832	1,822	1,846	2,022	2,011	2,323	2,024	2,307	2,115
Natural gas (mmcf/d)	**15.93**	15.22	15.51	15.70	17.38	19.14	19.45	20.22	24.69	19.18	20.49	21.50
Total (boe/d)	**15,452**	14,656	14,395	15,311	17,000	17,206	17,135	18,645	22,153	22,233	23,727	22,930
Consolidated												
Crude oil and condensate (bbls/d)	**35,738**	31,698	29,185	31,624	32,163	35,174	28,083	30,833	30,080	32,324	41,547	35,391
NGLs (bbls/d)	**12,656**	9,167	6,612	7,547	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901
Natural gas (mmcf/d)	**515.38**	369.36	279.59	280.73	269.39	274.59	283.92	263.80	283.63	247.61	234.23	234.12
Total (boe/d)	**134,290**	102,427	82,394	85,960	84,258	87,985	82,814	82,144	83,889	81,489	88,083	82,312

Financial results

	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22
Continuing operations:												
North America												
Crude oil and condensate sales ($/bbl)	**83.86**	91.67	93.49	94.81	101.35	89.71	99.69	94.82	156.65	98.34	103.03	112.73
NGL sales ($/bbl)	**23.37**	29.75	27.76	25.96	27.93	31.21	30.77	27.34	26.83	34.06	38.29	44.03
Natural gas sales ($/mcf)	**2.25**	2.77	1.99	0.97	1.31	2.11	2.64	2.47	2.33	4.17	5.95	6.34
Sales ($/boe)	**25.67**	31.26	30.81	28.11	30.60	31.01	34.46	33.20	35.09	40.89	51.00	54.32
Royalties ($/boe)	**(1.97)**	(3.51)	(1.96)	(3.22)	(2.83)	(3.42)	(3.98)	(3.39)	(2.31)	(4.96)	(5.20)	(9.96)
Transportation ($/boe)	**(2.77)**	(3.06)	(3.42)	(3.46)	(3.07)	(2.47)	(2.56)	(2.04)	(1.43)	(2.56)	(2.55)	(2.06)
Operating ($/boe)	**(7.55)**	(8.07)	(11.10)	(8.88)	(11.98)	(10.39)	(9.47)	(11.12)	(7.80)	(9.08)	(7.82)	(7.91)
General and administration ($/boe)	**(1.42)**	(3.33)	(2.01)	(0.81)	(1.86)	(1.71)	1.49	(0.12)	0.34	(1.31)	0.36	(2.28)
Corporate income taxes ($/boe)	**(0.28)**	(0.08)	0.60	(0.47)	1.19	(0.97)	0.34	(0.01)	(0.17)	(0.19)	(0.22)	(0.05)
Fund flows from operations ($/boe)	**11.68**	13.21	12.92	11.27	12.05	12.05	20.28	16.52	23.72	22.79	35.57	32.06
Fund flows from operations	**96,654**	70,248	45,006	40,046	41,638	39,214	69,202	57,957	68,895	77,559	113,783	100,895
Drilling and development	**(45,211)**	(121,851)	(85,682)	(54,522)	(43,594)	(110,864)	(40,674)	(39,245)	(53,352)	(86,886)	(84,677)	(48,957)
Free cash flow	**51,443**	(51,603)	(40,676)	(14,476)	(1,956)	(71,650)	28,528	18,712	15,543	(9,327)	29,106	51,938
International												
Crude oil and condensate sales ($/bbl)	**90.82**	108.97	110.31	114.16	116.24	119.68	123.77	114.26	100.23	107.57	128.02	140.09
Natural gas sales ($/mcf)	**15.22**	20.41	18.11	14.55	12.72	11.63	16.92	13.34	14.58	24.69	39.54	58.55
Sales ($/boe)	**91.13**	117.22	109.27	97.85	92.68	92.48	108.70	93.46	91.89	132.84	177.23	254.86
Royalties ($/boe)	**(5.10)**	(4.43)	(5.38)	(4.16)	(4.49)	(4.60)	(3.41)	3.55	(7.43)	(13.39)	(6.38)	(7.21)
Transportation ($/boe)	**(4.22)**	(4.63)	(3.37)	(3.81)	(4.20)	(3.65)	(3.91)	(4.53)	(5.23)	(5.11)	(3.29)	(3.51)
Operating ($/boe)	**(23.84)**	(27.50)	(25.08)	(27.11)	(26.56)	(25.30)	(22.64)	(25.58)	(28.24)	(31.41)	(23.35)	(22.63)
General and administration ($/boe)	**(4.81)**	(4.69)	(6.21)	(5.56)	(5.20)	(4.86)	(9.18)	(7.37)	(7.58)	(7.52)	(5.09)	(3.34)
Corporate income taxes ($/boe)	**(3.46)**	(7.22)	(6.53)	(3.74)	(6.08)	(7.06)	(7.81)	(13.42)	(6.79)	(11.20)	(15.15)	(21.97)
PRRT ($/boe)	**(0.30)**	(1.17)	1.16	(0.17)	(1.37)	(3.38)	7.93	—	—	—	(1.85)	(1.96)
Fund flows from operations ($/boe)	**49.40**	67.58	63.86	53.30	44.78	43.63	69.68	46.11	36.62	64.21	122.12	194.24
Fund flows from operations	**125,486**	174,350	176,883	157,048	119,310	139,054	183,353	107,704	99,377	123,893	332,377	449,771
Drilling and development	**(53,197)**	(36,654)	(42,341)	(40,638)	(47,830)	(45,789)	(73,604)	(49,701)	(28,347)	(37,258)	(43,957)	(65,640)
Exploration and evaluation	**(4,251)**	(14,655)	(24,154)	(2,460)	(1,260)	(8,144)	(10,579)	(6,235)	(2,775)	(1,492)	(11,456)	(6,137)
Free cash flow	**68,038**	123,041	110,388	113,950	70,220	85,121	99,170	51,768	68,255	85,143	276,964	377,994
Discontinued operations:												
North America												
Crude oil and condensate sales ($/bbl)	**81.28**	93.64	91.88	95.57	104.51	90.61	97.61	105.81	75.66	92.98	105.62	113.29
NGL sales ($/bbl)	**33.83**	47.63	37.41	35.94	46.43	46.90	45.49	33.84	34.03	46.92	50.88	53.73
Natural gas sales ($/mcf)	**1.71**	3.01	1.89	0.24	1.13	2.38	2.42	2.93	2.08	3.65	6.05	6.83
Sales ($/boe)	**64.23**	75.93	71.23	72.36	81.63	71.77	75.74	82.11	59.56	78.56	90.31	96.49
Royalties ($/boe)	**(11.95)**	(14.56)	(13.83)	(13.53)	(16.09)	(14.54)	(14.35)	(16.68)	(9.97)	(12.31)	(15.71)	(16.49)
Transportation ($/boe)	**(2.13)**	(2.23)	(2.04)	(2.26)	(2.26)	(2.11)	(2.18)	(2.18)	(1.76)	(2.24)	(2.23)	(2.32)
Operating ($/boe)	**(18.36)**	(21.14)	(23.72)	(19.44)	(18.14)	(22.27)	(15.89)	(14.08)	(18.59)	(22.65)	(21.84)	(23.08)
General and administration ($/boe)	**(7.35)**	(3.69)	(2.44)	(1.81)	(4.06)	(1.68)	(0.47)	(1.94)	(0.24)	(0.45)	(0.29)	0.23
Fund flows from operations ($/boe)	**24.44**	34.31	29.20	35.32	41.07	31.17	42.85	47.23	29.00	40.91	50.24	54.83
Fund flows from operations	**34,362**	45,258	38,656	49,747	63,549	48,813	67,564	81,003	58,451	81,876	109,660	115,684
Drilling and development	**(12,830)**	(8,959)	(48,482)	(23,649)	(17,926)	(25,645)	(18,030)	(30,458)	(82,371)	(29,184)	(29,215)	(63,281)
Free cash flow	**21,532**	36,299	(9,826)	26,098	45,623	23,168	49,534	50,545	(23,920)	52,692	80,445	52,403

	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22
Consolidated												
Crude oil and condensate sales ($/bbl)	**85.07**	99.36	100.06	103.55	108.93	104.26	107.91	106.94	96.64	98.62	115.02	123.02
NGL sales ($/bbl)	**24.68**	31.56	29.38	27.49	31.61	34.16	33.38	27.77	28.11	36.23	39.93	44.64
Natural gas sales ($/mcf)	**4.88**	7.80	8.47	6.57	5.69	6.10	8.48	6.32	7.37	10.77	17.43	24.68
Sales ($/boe)	**43.71**	61.71	66.54	61.97	62.46	63.45	68.64	62.92	61.74	75.36	103.99	127.39
Royalties ($/boe)	**(3.77)**	(5.35)	(5.28)	(5.40)	(6.08)	(6.06)	(5.93)	(4.26)	(6.16)	(9.18)	(8.43)	(10.94)
Transportation ($/boe)	**(3.00)**	(3.38)	(3.16)	(3.38)	(3.30)	(2.87)	(2.95)	(2.84)	(2.87)	(3.14)	(2.71)	(2.57)
Operating ($/boe)	**(12.18)**	(15.38)	(18.41)	(17.55)	(18.29)	(18.65)	(15.35)	(16.26)	(17.91)	(18.66)	(16.81)	(16.64)
General and administration ($/boe)	**(2.80)**	(3.76)	(3.62)	(2.76)	(3.46)	(2.96)	(2.60)	(2.77)	(2.63)	(2.71)	(1.65)	(1.90)
Corporate income taxes ($/boe)	**(0.91)**	(2.07)	(2.11)	(1.61)	(1.58)	(3.20)	(2.57)	(7.05)	(7.04)	(5.96)	(32.68)	(6.74)
PRRT ($/boe)	**(0.06)**	(0.33)	0.43	(0.06)	(0.47)	(1.35)	2.74	—	—	—	(0.62)	(0.60)
Interest ($/boe)	**(3.08)**	(3.58)	(3.16)	(2.68)	(2.75)	(2.30)	(3.01)	(2.68)	(2.65)	(2.98)	(2.78)	(3.23)
Equity based compensation ($/boe)	**(0.47)**	—	—	—	(1.87)	—	—	—	—	—	—	—
Realized derivatives ($/boe)	**3.90**	1.21	3.80	6.31	6.00	27.55	10.33	9.74	8.86	1.95	(5.42)	(18.22)
Realized foreign exchange ($/boe)	**(0.04)**	0.27	0.32	0.15	0.30	0.23	(0.73)	0.28	0.48	(0.65)	2.33	(0.28)
Realized other ($/boe)	**(0.05)**	(1.57)	(0.68)	(0.21)	(0.09)	0.02	0.26	(1.32)	0.53	0.49	(0.14)	0.80
Fund flows from operations ($/boe)	**21.25**	27.77	34.67	34.78	30.87	53.86	48.83	35.76	32.35	34.52	35.08	67.07

Fund flows from operations	**259,678**	256,029	262,698	275,024	236,703	431,358	372,117	270,218	247,109	253,167	284,220	507,876
Drilling and development	**(111,238)**	(167,464)	(176,505)	(118,809)	(109,350)	(182,298)	(132,308)	(119,404)	(164,070)	(153,328)	(157,849)	(177,878)
Exploration and evaluation	**(4,251)**	(14,655)	(24,154)	(2,460)	(1,260)	(8,144)	(10,579)	(6,235)	(2,775)	(1,492)	(11,456)	(6,137)
Free cash flow	**144,189**	73,910	62,039	153,755	126,093	240,916	229,230	144,579	80,264	98,347	114,915	323,861

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 Accounting Standards 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 loss, FFO is a non-GAAP financial measure and total of segments measure comprised of sales less royalties, transportation, operating, G&A, corporate income tax, PRRT, 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 by management 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 most directly comparable primary financial statement measures can be found below. Fund flows from continuing operations and fund flows from discontinued operations are calculated in the same manner as FFO and are most directly comparable to net earnings (loss) from continuing operations and net earnings (loss) discontinued operations, respectively.

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**443,834**	**41.04**	352,637	57.62	**912,527**	**48.76**	748,304	59.57
Royalties	**(29,268)**	**(2.71)**	(21,724)	(3.55)	**(59,359)**	**(3.17)**	(47,510)	(3.78)
Transportation	**(33,612)**	**(3.11)**	(21,820)	(3.57)	**(61,853)**	**(3.31)**	(41,486)	(3.30)
Operating	**(123,006)**	**(11.37)**	(112,165)	(18.33)	**(236,904)**	**(12.66)**	(226,606)	(18.04)
General and administration	**(23,937)**	**(2.21)**	(20,262)	(3.31)	**(53,725)**	**(2.87)**	(37,700)	(3.00)
Corporate income tax expense	**(11,116)**	**(1.03)**	(12,080)	(1.97)	**(30,175)**	**(1.61)**	(37,719)	(3.00)
Petroleum resource rent tax	**(755)**	**(0.07)**	(3,638)	(0.59)	**(3,773)**	**(0.20)**	(14,421)	(1.15)
Interest expense	**(37,691)**	**(3.49)**	(21,062)	(3.44)	**(70,670)**	**(3.78)**	(39,454)	(3.14)
Equity based compensation	**(5,692)**	**(0.53)**	(14,361)	(2.35)	**(5,692)**	**(0.30)**	(14,361)	(1.14)
Realized gain on derivatives	**47,699**	**4.41**	46,017	7.52	**58,818**	**3.14**	266,632	21.23
Realized foreign exchange (loss) gain	**(487)**	**(0.05)**	2,267	0.37	**2,012**	**0.11**	4,138	0.33
Realized other expense	**(653)**	**(0.06)**	(655)	(0.11)	**(15,119)**	**(0.81)**	(472)	(0.04)
Fund flows from continuing operations	**225,316**	**20.82**	173,154	28.29	**436,087**	**23.30**	559,345	44.54
Equity based compensation	**(1,286)**		3,860		**(7,217)**		(1,658)	
Unrealized gain (loss) on derivative instruments [(1)]	**70,569**		(125,789)		**56,894**		(314,533)	
Unrealized foreign exchange gain (loss) [(1)]	**6,002**		2,344		**(30,012)**		(18,863)	
Accretion	**(17,716)**		(16,146)		**(33,517)**		(32,050)	
Depletion and depreciation	**(165,761)**		(131,826)		**(314,044)**		(280,003)	
Deferred tax expense	**(41,345)**		(14,196)		**(28,390)**		(29,331)	
Unrealized other expense [(1)]	**(1,394)**		(208)		**(1,713)**		(345)	
Net earnings (loss) from continuing operations	**74,385**		(108,807)		**78,088**		(117,438)	

	Q2 2025		Q2 2024		YTD 2025		YTD 2024	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**90,314**	**64.23**	126,288	81.63	**190,467**	**69.89**	238,656	76.67
Royalties	**(16,800)**	**(11.95)**	(24,886)	(16.09)	**(35,999)**	**(13.21)**	(47,653)	(15.31)
Transportation	**(2,999)**	**(2.13)**	(3,497)	(2.26)	**(5,944)**	**(2.18)**	(6,793)	(2.18)
Operating	**(25,819)**	**(18.36)**	(28,065)	(18.14)	**(53,698)**	**(19.70)**	(62,935)	(20.22)
General and administration	**(10,334)**	**(7.35)**	(6,275)	(4.06)	**(15,206)**	**(5.58)**	(12,540)	(4.03)
Corporate income tax expense	**—**	**—**	(16)	(0.01)	**—**	**—**	(19)	(0.01)
Fund flows from discontinued operations	**34,362**	**24.44**	63,549	41.07	**79,620**	**29.22**	108,716	34.92
Unrealized loss on derivative instruments [1]	**(11,047)**		—		**(11,047)**		—	
Unrealized foreign exchange (loss) gain [1]	**(552)**		725		**(437)**		291	
Accretion	**(2,156)**		(2,063)		**(4,235)**		(4,093)	
Depletion and depreciation	**(18,406)**		(29,358)		**(46,511)**		(59,615)	
Deferred tax recovery (expense)	**62,342**		(6,471)		**58,403**		(7,981)	
Impairment expense	**(372,386)**		—		**(372,386)**		—	
Net (loss) earnings from discontinued operations	**(307,843)**		26,382		**(296,593)**		37,318	
Fund flows from operations	**259,678**	**21.25**	236,703	30.87	**515,707**	**24.03**	668,061	42.61
Net loss	**(233,458)**		(82,425)		**(218,505)**		(80,120)	

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

Non-GAAP Financial Measures and Non-GAAP Ratios

Fund flows from operations per basic and diluted share: FFO per share and diluted share are non-GAAP ratios. 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 Accounting Standards. 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. Fund flows from continuing operations per basic and diluted share and fund flows from discontinued operations per basic and diluted share are calculated in the same manner as FFO per basic and diluted share.

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. Fund flows from continuing operations per boe and fund flows from discontinued operations per boe are calculated in the same manner as FFO per boe.

Free cash flow (FCF): Most directly comparable to cash flows from operating activities, FCF is a non-GAAP financial 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)	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Cash flows from operating activities	**140,467**	266,322	**420,851**	620,617
Changes in non-cash operating working capital	**110,825**	(41,364)	**77,123**	30,724
Asset retirement obligations settled	**8,386**	11,745	**17,733**	16,720
Fund flows from operations	**259,678**	236,703	**515,707**	668,061
Drilling and development	**(111,238)**	(109,350)	**(278,702)**	(291,648)
Exploration and evaluation	**(4,251)**	(1,260)	**(18,906)**	(9,404)
Free cash flow	**144,189**	126,093	**218,099**	367,009

Capital expenditures: Most directly comparable to cash flows used in investing activities, capital expenditures is a non-GAAP financial 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)	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Drilling and development	**111,238**	109,350	**278,702**	291,648
Exploration and evaluation	**4,251**	1,260	**18,906**	9,404
Capital expenditures	**115,489**	110,610	**297,608**	301,052

Payout and payout % of FFO: Payout and payout % of FFO are, respectively, a non-GAAP financial measure and non-GAAP ratio. Payout is 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. 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)	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Dividends declared	**20,022**	18,981	**40,065**	38,164
Drilling and development	**111,238**	109,350	**278,702**	291,648
Exploration and evaluation	**4,251**	1,260	**18,906**	9,404
Asset retirement obligations settled	**8,386**	11,745	**17,733**	16,720
Payout	**143,897**	141,336	**355,406**	355,936
% of fund flows from operations	**55 %**	60 %	**69 %**	53 %

Return on capital employed (ROCE): A non-GAAP ratio, ROCE is a measure that management uses 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 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.

	Twelve Months Ended	
($M)	Jun 30, 2025	Jun 30, 2024
Net loss	**(185,124)**	(825,947)
Taxes	**(45,383)**	(11,691)
Interest expense	**115,822**	82,581
EBIT	**(114,685)**	(755,057)
Average capital employed	**5,803,980**	5,906,288
Return on capital employed	**(2)%**	(13)%

Adjusted working capital (deficit): Adjusted working capital (deficit) is a non-GAAP financial measure calculated 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.

	As at	
($M)	Jun 30, 2025	Dec 31, 2024
Current assets	**1,171,777**	582,326
Current liabilities	**(603,527)**	(610,590)
Current derivative asset	**(76,558)**	(40,312)
Current lease liability [(1)]	**12,348**	12,206
Current derivative liability [(1)]	**36,462**	52,944
Adjusted working capital	**540,502**	(3,426)

[(1)] Current lease liability includes the lease liability associated with assets held for sale. Current derivative liability includes the derivative liability associated with assets held for sale. See Note 4 - "Discontinued Operations" for more information.

Acquisitions: Acquisitions is a non-GAAP financial measure and is calculated as 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. Management believes 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)	Q2 2025	Q2 2024	YTD 2025	YTD 2024
Acquisitions, net of cash acquired	**1,591**	5,450	**1,086,047**	5,829
Shares issued for acquisition	**—**	—	**13,363**	—
Acquisition of securities	**—**	—	**—**	9,373
Acquired working capital deficit	**—**	—	**23,179**	—
Acquisitions	**1,591**	5,450	**1,122,589**	15,202

Operating netback: Operating netback is non-GAAP financial measure and is calculated as sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses, and when presented on a per unit basis, is a non-GAAP ratio. Operating netback is most directly comparable to net loss. Management assesses operating netback as a measure of the profitability and efficiency of our field operations.

Net debt to four quarter trailing fund flows from operations: Management uses net debt (a capital management measure, as defined below) 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 a non-GAAP ratio and is calculated as net debt (capital management measure) divided by fund flows from operations (total of segments measure) from the preceding four quarters.

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.

	As at	
($M)	Jun 30, 2025	Dec 31, 2024
Long-term debt	**1,951,250**	963,456
Adjusted working capital [1]	**(540,502)**	3,426
Unrealized FX on swapped USD borrowings	**2,573**	—
Net debt	**1,413,321**	966,882
Ratio of net debt to four quarter trailing fund flows from operations [2]	**1.4**	0.8

(1) Adjusted working capital is defined as current assets (excluding current derivatives), less current liabilities (excluding current derivatives and current lease liabilities). These figures include amounts for assets held for sale and liabilities associated with assets held for sale which represent the estimated cash proceeds from dispositions that closed subsequent to June 30, 2025.

(2) Subsequent to February 26, 2025, net debt to four quarter trailing fund flows from operations is calculated inclusive of Westbrick Energy's pre-acquisition four quarter trailing fund flows from operations, as if the acquisition of Westbrick Energy occurred at the beginning of the four-quarter trailing period, and exclusive of the four quarter trailing fund flows from discontinued operations from assets held for sale to reflect the Company's ability to repay debt on a pro forma basis.

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)	Q2 2025	Q2 2024
Shares outstanding	**154,019**	158,174
Potential shares issuable pursuant to the LTIP	**4,737**	3,498
Diluted shares outstanding	**158,756**	161,672

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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 Safety & Sustainability Committee Chair (Independent)
7 Safety & Sustainability Committee Member (Independent)
8 Technical Committee Chair (Independent)
9 Technical Committee Member (Independent)

OFFICERS / CORPORATE SECRETARY

Dion Hatcher
President & Chief Executive Officer

Lars Glemser
Vice President & Chief Financial Officer

Lara Conrad
Vice President Business Development

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

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

JPMorgan Chase Bank, N.A., Toronto Branch

Goldman Sachs Lending Partners LLC

EVALUATION ENGINEERS

McDaniel & Associates
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

Odyssey Trust Company

STOCK EXCHANGE LISTINGS

The Toronto Stock Exchange (“VET”)
The New York Stock Exchange (“VET”)

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