Q2 2021

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 financial outlooks under applicable securities legislation. Such forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project", 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; business strategies and objectives; operational and financial performance; estimated reserve quantities and the discounted net present value of future net revenue from such reserves; petroleum and natural gas sales; future production levels (including the timing thereof) and rates of average annual production growth; exploration and development plans; acquisition and disposition plans and the timing thereof; operating and other expenses, including the payment and amount of future dividends; royalty and income tax rates; 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; and management's expectations relating to the timing and results of exploration and development activities.

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 and interest rates; 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 Vermilion; and other risks and uncertainties described elsewhere in this document or in Vermilion's other filings with Canadian securities regulatory authorities.

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 contains metrics commonly used in the oil and gas industry. These oil and gas metrics do not have any standardized meaning or standard methods of calculation and therefore may not be comparable to similar measures presented by other companies where similar terminology is used and should therefore not be used to make comparisons. Natural gas volumes have been converted on the basis of six thousand cubic feet of natural gas to one barrel of oil equivalent. Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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

Abbreviations

$M	thousand dollars
$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
GJ	gigajoules
LSB	light sour blend crude oil reference price
mbbls	thousand barrels
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point.
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
tCO2e	tonnes of carbon dioxide equivalent
TTF	the price for natural gas in the Netherlands, quoted in megawatt hours of natural gas, at the Title Transfer Facility Virtual Trading Point
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated August 13, 2021, 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, 2021 compared with the corresponding periods 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, 2021 and the audited consolidated financial statements for the years ended December 31, 2020 and 2019, together with the accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR at www.sedar.com 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, 2021 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with IAS 34, "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB").

This MD&A includes references to certain financial and performance measures which do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS"). These measures include:

- Fund flows from operations: Fund flows from operations is a 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" for a reconciliation of fund flows from operations to net earnings. We analyze fund flows from operations both on a consolidated basis and on a business unit basis in order to assess the contribution of each business unit to our ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.
- Free cash flow: Represents fund flows from operations in excess of capital expenditures. We use free cash flow to determine the funding available for investing and financing activities, including payment of dividends, repayment of long-term debt, reallocation to existing business units, and deployment into new ventures. We also assess free cash flow as a percentage of fund flows from operations, which is a measure of the percentage of fund flows from operations that is retained for incremental investing and financing activities.
- Net debt: Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements". Net debt is comprised of long-term debt plus current liabilities less current assets and represents Vermilion's net financing obligations after adjusting for the timing of working capital fluctuations. Net debt excludes non-current lease obligations which are secured by a corresponding right-of-use asset. Please see "Capital disclosures" in the "Notes to the Condensed Consolidated Interim Financial Statements" for additional information.
- Netbacks: Netbacks are per boe and per mcf performance measures used in the analysis of operational activities. We assess netbacks both on a consolidated basis and on a business unit basis in order to compare and assess the operational and financial performance of each business unit versus other business units and also versus third party crude oil and natural gas producers.

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

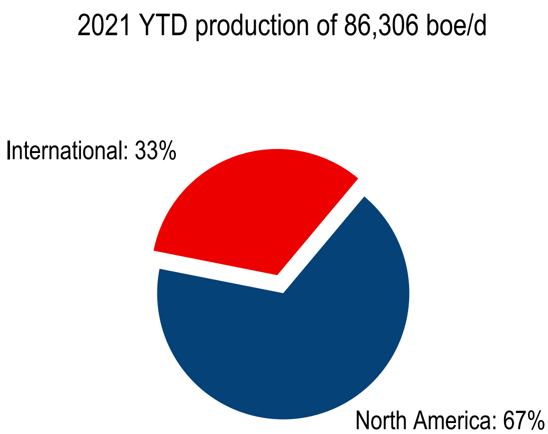
On January 18, 2021, we released our 2021 capital budget and associated production guidance.

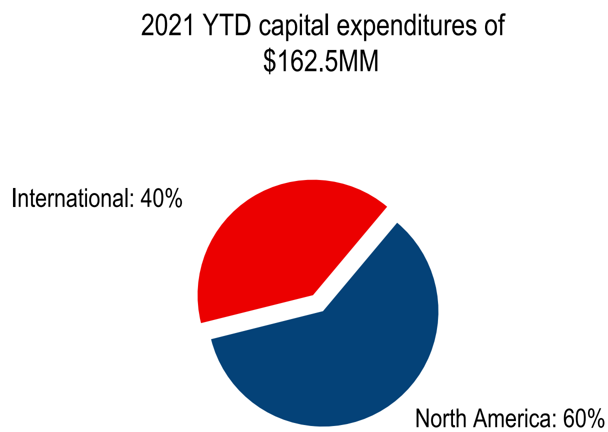
The following table summarizes our guidance:

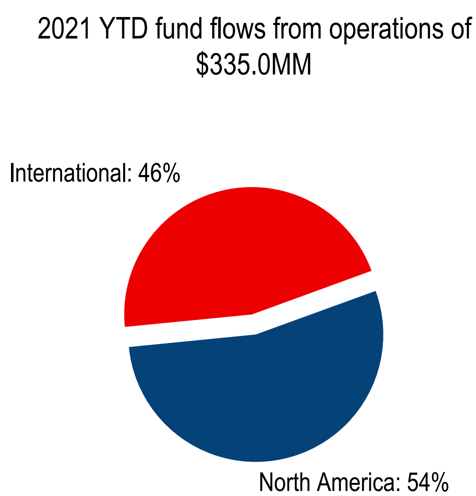
	Date	Capital Expenditures ($MM)	Production (boe/d)
2021 Guidance			
2021 Guidance	January 18, 2021	300	83,000 to 85,000

Vermilion's Business

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







Consolidated Results Overview

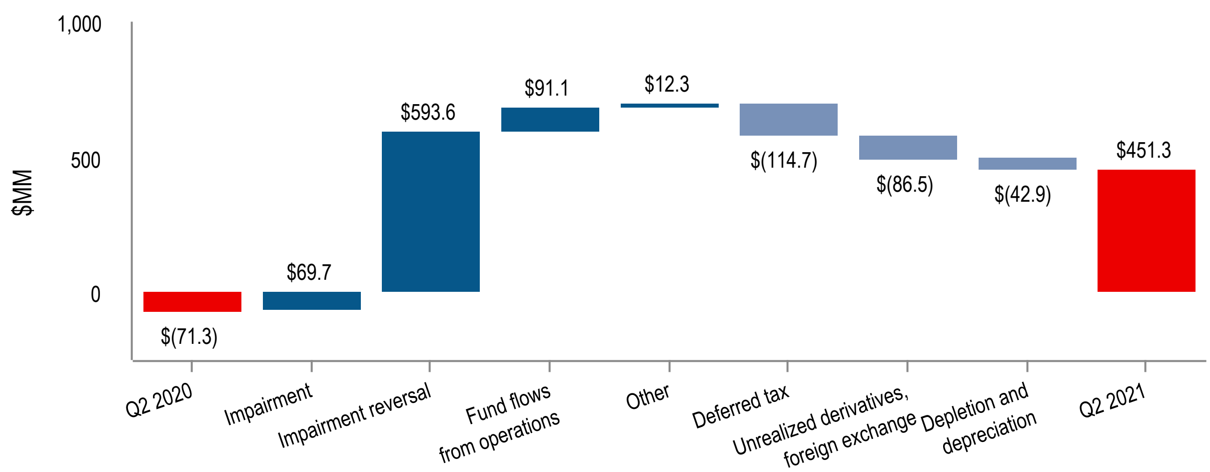
	Q2 2021	Q2 2020	Q2/21 vs. Q2/20	YTD 2021	YTD 2020	2021 vs. 2020
Production [1]						
Crude oil and condensate (bbls/d)	**38,354**	45,041	(15)%	**38,777**	44,961	(14)%
NGLs (bbls/d)	**8,695**	9,588	(9)%	**8,386**	8,805	(5)%
Natural gas (mmcf/d)	**235.72**	274.42	(14)%	**234.86**	269.96	(13)%
Total (boe/d)	**86,335**	100,366	(14)%	**86,306**	98,760	(13)%
Build (draw) in inventory (mbbls)	**15**	115		**299**	(76)	
Financial metrics						
Fund flows from operations ($M)	**172,942**	81,852	111%	**334,993**	252,077	33%
Per share ($/basic share)	**1.07**	0.52	106%	**2.09**	1.60	31%
Net earnings (loss) ($M)	**451,274**	(71,290)	N/A	**951,238**	(1,389,794)	N/A
Per share ($/basic share)	**2.79**	(0.45)	N/A	**5.94**	(8.83)	N/A
Free cash flow	**93,766**	39,578	137%	**172,454**	(23,901)	N/A
Net debt ($M)	**2,005,272**	2,161,442	(7)%	**2,005,272**	2,161,442	(7)%
Activity						
Capital expenditures ($M)	**79,176**	42,274	87%	**162,539**	275,978	(41)%
Acquisitions ($M)	**11,859**	2,932		**12,252**	14,269	

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

Financial performance review

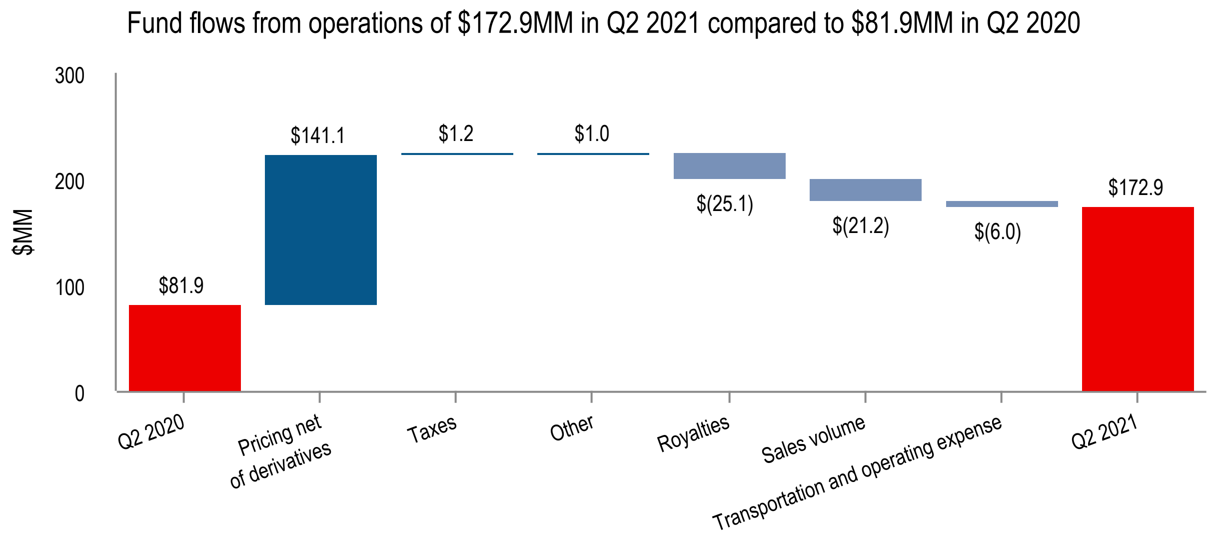
Q2 2021 vs. Q2 2020

Net earnings of $451.3MM in Q2 2021 compared to a net loss of $71.3MM in Q2 2020



"Other" contains equity based compensation, accretion expense and unrealized other

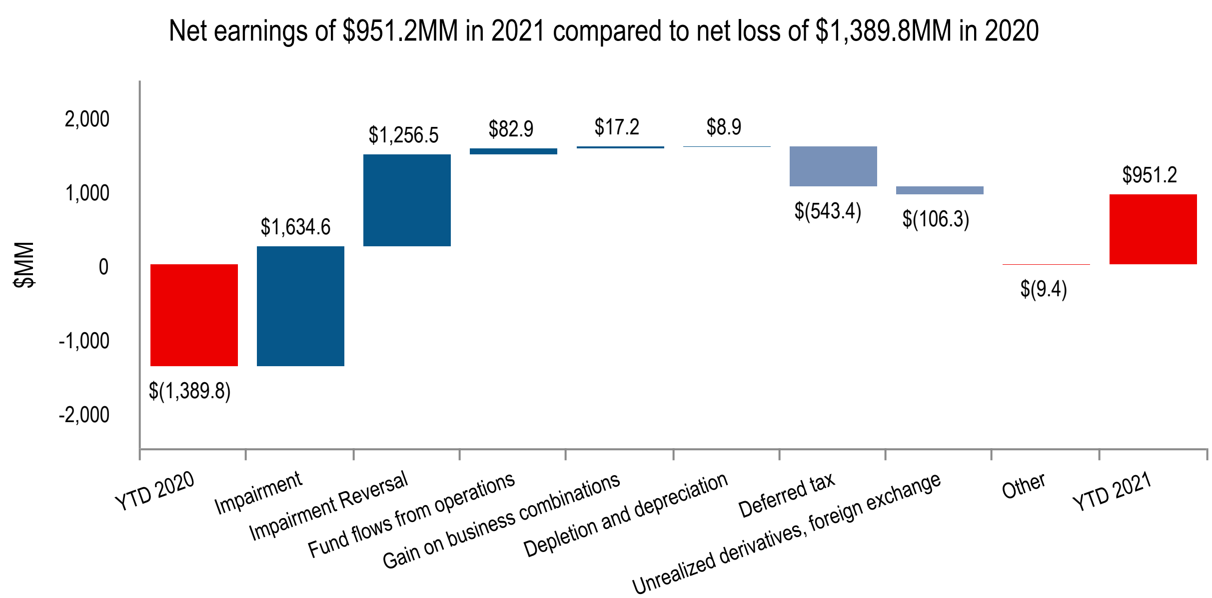
- We recorded net earnings of $451.3 million ($2.79/basic share) for Q2 2021 compared to a net loss of $71.3 million ($0.45/basic share) in Q2 2020. The increase was primarily driven by impairment reversals of $593.6 million in Q2 2021 and an increase in FFO primarily driven by an increase in realized pricing. This was partially offset by an increase in deferred taxes driven by impairment reversals in Q2 2021 and unrealized losses on derivatives due to increased commodity prices.



"Other" contains general and administration, interest, and realized foreign exchange

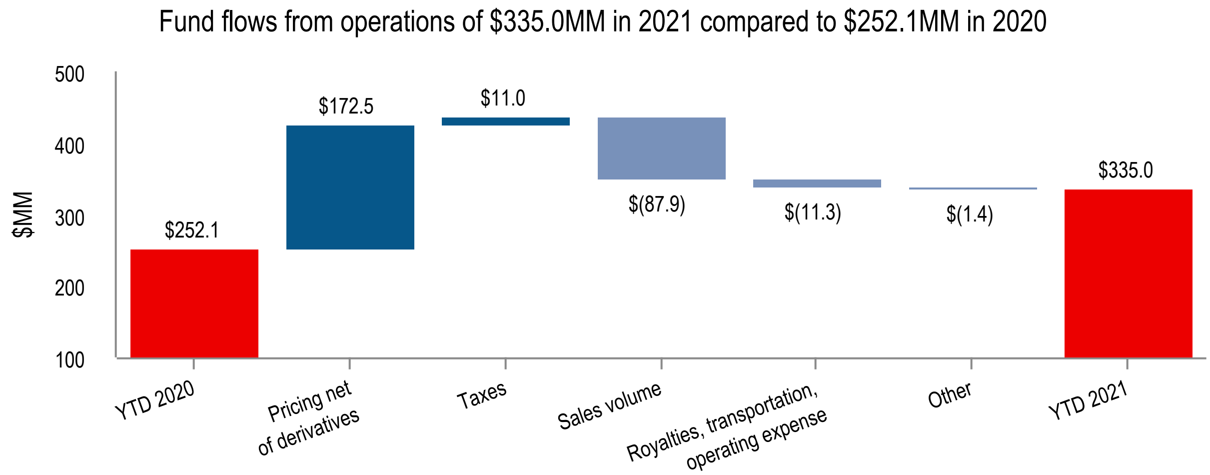
- We generated fund flows from operations of $172.9 million in Q2 2021, an increase from $81.9 million in Q2 2020 primarily as a result of higher commodity prices which is reflected in our consolidated realized price per boe increasing from $21.40/boe in Q2 2020 to $51.93/boe in Q2 2021. This was partially offset by increased royalties driven by increased pricing and a decrease in sales volumes primarily driven by natural decline.

YTD 2021 vs. YTD 2020



"Other" contains equity based compensation, accretion and unrealized other

- For the six months ended June 30, 2021, we achieved net earnings of $951.2 million compared to a net loss of $1,389.8 million for the comparable period in 2020. The increase in net earnings was primarily due to impairment charges we recorded of $1,236.7 million in 2020 (net of $397.9 million income tax recovery), impairment reversal charges we recorded of $952.6 million in 2021 (net of $303.9 million income tax expense) and higher fund flows from operations driven by increased consolidated realized pricing. These increases were partially offset by higher unrealized derivative losses driven by increased commodity prices.



"Other" contains general and administration, interest, and realized foreign exchange

- Fund flows from operations increased by 33% for the six months ended June 30, 2021 versus the same period in 2020 primarily driven by a 75% increase in our consolidated realized price from $28.88/boe to $50.60/boe resulting from higher commodity prices. Sales volumes decreased year-over-year primarily due to natural decline in North America, Ireland, and Netherlands, as well as timing of liftings in Australia.

Production review

Q2 2021 vs. Q2 2020

- Consolidated average production of 86,335 boe/d in Q2 2021 represented a decrease of 14% from Q2 2020 production of 100,366 boe/d. Production decreases were mainly in Canada of 8,569 boe/d and in the United States of 2,972 boe/d due to natural decline and reduced capital activity as we are focused on maximizing free cash flow and reducing debt in 2021.

YTD 2021 *vs.* YTD 2020

- Consolidated average production of 86,306 boe/d for the six months ended June 30, 2021 represented a decrease of 13% from the prior year comparable period of 98,760 boe/d. Production decreases were mainly in Canada of 7,843 boe/d and in the United States of 1,644 boe/d due to natural decline and reduced capital activity.

Activity review

- For the three months ended June 30, 2021, capital expenditures of $79.2 million were incurred.
- In our North America core region, capital expenditures of $38.8 million were incurred during Q2 2021. In Canada, $20.2 million was incurred primarily related to drilling and completions activity. In south-east Saskatchewan we drilled eight (6.9 net) wells and completed six (5.4 net) wells. Five (4.4 net) wells were brought on production during the quarter. In addition, we drilled one (0.2 net) and brought two (1.7 net) Mannville natural gas wells on production. In the United States, we completed and brought on production two (2.0 net) wells in the quarter.
- In our International core region, capital expenditures of $40.3 million were incurred during Q2 2021. Our activities included $13.1 million incurred in Australia primarily for riser replacement work, $8.9 million in France mainly due to increased activity on subsurface maintenance and facilities, $7.7 million in the Netherlands mainly related to the drilling of one (1.0 net) wells, and $6.8 million in Central and Eastern Europe mainly related to land and seismic expenditures in Croatia.

Financial sustainability review

Free cash flow

- Free cash flow increased by $196.4 million for the six months ended June 20, 2021 compared to the prior year period. This was primarily the result of a 75% increase in consolidated realized prices, as well as lower capital spending due to a focus on generating free cash flow and reducing debt in 2021.

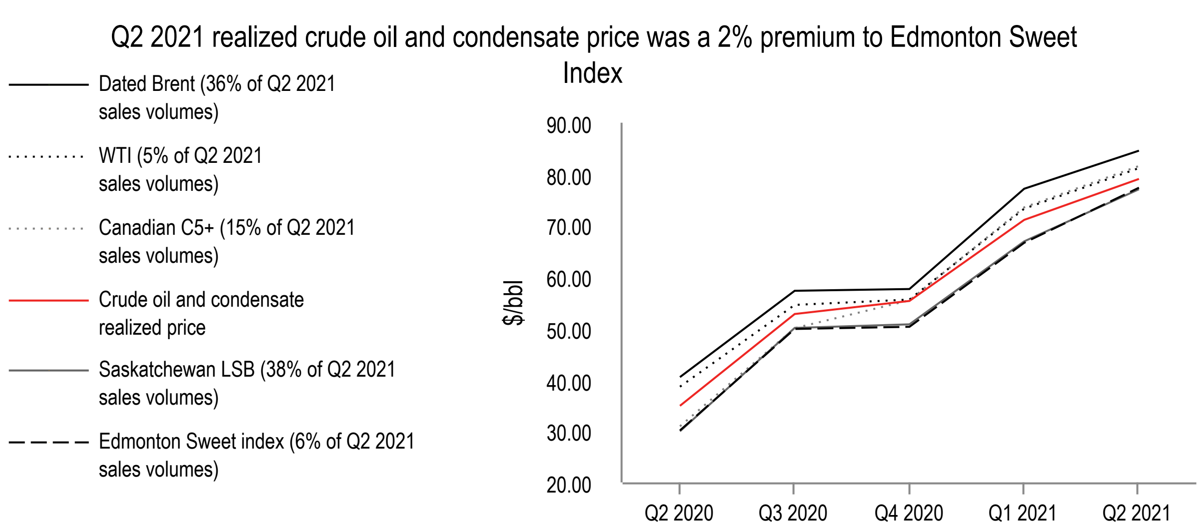
Long-term debt and net debt

- Long-term debt decreased to $1.8 billion as at June 30, 2021 from $1.9 billion as at December 31, 2020.
- Net debt decreased to $2.0 billion as at June 30, 2021 from $2.1 billion as at December 31, 2020, mainly due to a decrease in long-term debt of $164 million as a result of debt repayments.
- The ratio of net debt to four quarter trailing fund flows from operations decreased to 3.43 as at June 30, 2021 (December 31, 2020 - 4.19) mainly due to lower net debt combined with higher four quarter trailing fund flows from operations.

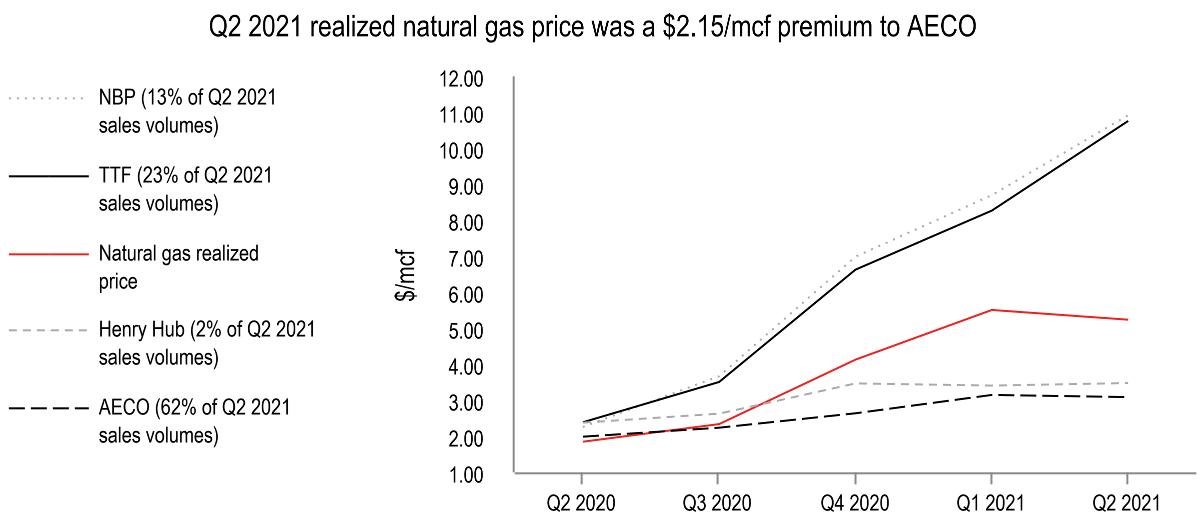
Benchmark Commodity Prices

	Q2 2021	Q2 2020	Q2/21 vs. Q2/20	YTD 2021	YTD 2020	2021 vs. 2020
Crude oil						
WTI ($/bbl)	**81.17**	38.62	110%	**77.31**	50.54	53%
WTI (US $/bbl)	**66.07**	27.85	137%	**61.96**	37.01	67%
Edmonton Sweet index ($/bbl)	**77.35**	30.11	157%	**72.09**	41.17	75%
Edmonton Sweet index (US $/bbl)	**62.96**	21.71	190%	**57.78**	30.15	92%
Saskatchewan LSB index ($/bbl)	**77.05**	29.95	157%	**72.08**	40.98	76%
Saskatchewan LSB index (US $/bbl)	**62.71**	21.60	190%	**57.77**	30.01	93%
Canadian C5+ Condensate index ($/bbl)	**81.58**	30.92	164%	**77.63**	46.82	66%
Canadian C5+ Condensate index (US $/bbl)	**66.40**	22.30	198%	**62.22**	34.29	82%
Dated Brent ($/bbl)	**84.56**	40.49	109%	**80.93**	54.25	49%
Dated Brent (US $/bbl)	**68.83**	29.20	136%	**64.86**	39.73	63%
Natural gas						
AECO ($/mcf)	**3.09**	1.99	55%	**3.12**	2.01	55%
NBP ($/mcf)	**10.92**	2.26	383%	**9.83**	3.31	197%
NBP (€/mcf)	**7.37**	1.48	398%	**6.53**	2.20	197%
TTF ($/mcf)	**10.76**	2.39	350%	**9.54**	3.32	187%
TTF (€/mcf)	**7.27**	1.56	366%	**6.34**	2.21	187%
Henry Hub ($/mcf)	**3.48**	2.38	46%	**3.45**	2.50	38%
Henry Hub (US $/mcf)	**2.83**	1.72	65%	**2.76**	1.83	51%
Average exchange rates						
CDN $/US $	**1.23**	1.39	(12)%	**1.25**	1.37	(9)%
CDN $/Euro	**1.48**	1.53	(3)%	**1.50**	1.50	—%
Realized prices						
Crude oil and condensate ($/bbl)	**79.06**	34.90	127%	**75.21**	47.20	59%
NGLs ($/bbl)	**25.43**	8.94	185%	**27.32**	8.94	206%
Natural gas ($/mcf)	**5.24**	1.85	183%	**5.37**	2.39	125%
Total ($/boe)	**51.93**	21.40	143%	**50.60**	28.88	75%

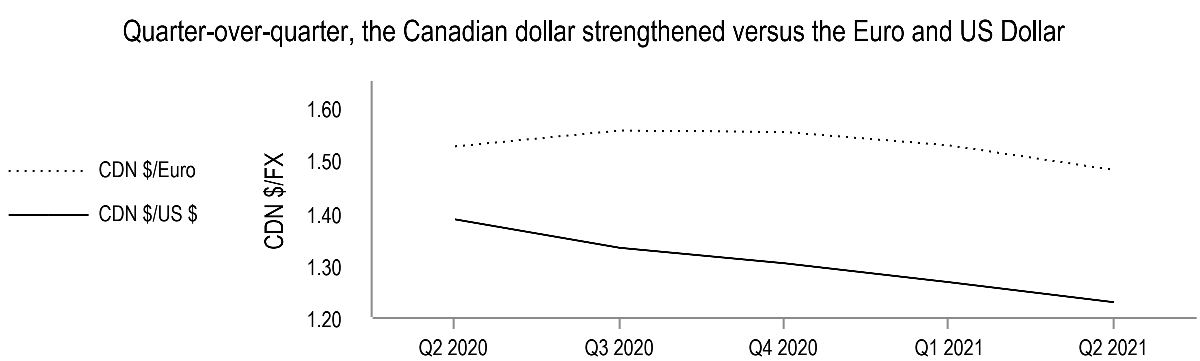
As an internationally diversified producer, we are exposed to a range of commodity prices. In our North America core region, our crude oil is sold at benchmarks linked to WTI (including the Edmonton Sweet index, the Saskatchewan LSB index, and the Canadian C5+ index) and our natural gas is sold at the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



- Crude oil prices increased in Q2 2021 relative to Q2 2020 due to continued global demand recovery, a coordinated supply cut from the OPEC+ group, and lower US shale production. Year-over-year, Canadian dollar WTI and Brent prices rose 110% and 109% respectively.
- In Canadian dollar terms, year-over-year, the Edmonton Sweet differential improved by $4.69/bbl to a discount of $3.82/bbl against WTI, and the Saskatchewan LSB differential improved by $4.55/bbl to a discount of $4.12/bbl against WTI.
- Approximately 36% of Vermilion's Q2 2021 crude oil and condensate production was priced at the Dated Brent index (which averaged a premium to WTI of US$2.76/bbl), while the remainder of our crude oil and condensate production was priced at the Saskatchewan LSB, Canadian C5+, Edmonton Sweet, and WTI indices.



- In Canadian dollar terms, prices for European natural gas (NBP and TTF) rose by 383% and 350%, respectively, in Q2 2021 compared to Q2 2020. A rebalancing of the European gas market has been driven by a demand recovery, lower supply from both pipeline flows and LNG imports, and higher European carbon prices.
- Natural gas prices at AECO in Q2 2021 increased by 55% compared to Q2 2020, with seasonal demand and supportive storage balances improving prices.
- For Q2 2021, average European natural gas prices represented a $7.75/mcf premium to AECO. Approximately 36% of our natural gas production in Q2 2021 benefited from this premium European pricing.



- For the three months ended June 30, 2021, the Canadian dollar strengthened 3% against the Euro quarter-over-quarter.
- For the three months ended June 30, 2021, the Canadian dollar strengthened 3% against the US dollar quarter-over-quarter.

North America

	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Production [(1)]				
Crude oil and condensate (bbls/d)	**24,316**	31,569	**24,480**	30,728
NGLs (bbls/d)	**8,695**	9,588	**8,386**	8,805
Natural gas (mmcf/d)	**152.06**	172.43	**148.23**	165.16
Total production volume (boe/d)	**58,354**	69,895	**57,572**	67,059

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

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**224,609**	**42.30**	116,009	18.24	**444,743**	**42.68**	286,800	23.50
Royalties	**(31,755)**	**(5.98)**	(10,613)	(1.67)	**(59,835)**	**(5.74)**	(31,314)	(2.57)
Transportation	**(10,084)**	**(1.90)**	(10,934)	(1.72)	**(20,568)**	**(1.97)**	(22,072)	(1.81)
Operating	**(57,830)**	**(10.89)**	(61,046)	(9.60)	**(115,111)**	**(11.05)**	(130,780)	(10.72)
General and administration [(1)]	**(4,825)**	**(0.91)**	(9,674)	(1.52)	**(11,673)**	**(1.12)**	(14,612)	(1.20)
Corporate income tax (expense) [(1)]	**(199)**	**(0.04)**	(103)	(0.02)	**(413)**	**(0.04)**	(335)	(0.03)
Fund flows from operations	**119,916**	**22.58**	23,639	3.72	**237,143**	**22.76**	87,687	7.18
Capital expenditures	**(38,847)**		(23,979)		**(97,960)**		(221,905)	
Free cash flow	**81,069**		(340)		**139,183**		(134,218)	

(1) Includes amounts from Corporate segment.

In North America, production averaged 58,354 in Q2 2021, a decrease of 17% year-over-year primarily due to natural decline and reduced capital activity as we focused on maximizing free cash flow and reducing debt.

In Q2 2021, we drilled one (0.2 net) well and brought two (1.7 net) condensate-rich Mannville natural gas wells on production in west-central Alberta from our Q1 2021 drilling campaign. In south-east Saskatchewan we initiated our drilling campaign where we drilled eight (6.9 net) wells and completed six (5.4 net) wells, of which five (4.4 net) wells were brought on production during the quarter. The remaining wells will be brought on production in Q3 2021.

In the United States business unit, we moved one of our experienced drilling crews from our Canadian program to Wyoming and commenced our four (4.0 net) well drilling program, centered on Turner horizontal wells in the Powder River basin. Two of the wells were completed and brought on production in the quarter. The remaining two wells are expected to be completed and brought on production in Q3 2021.

Sales

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Canada	**206,848**	**41.62**	100,135	17.41	**402,656**	**41.57**	255,098	22.84
United States	**17,761**	**52.24**	15,874	26.00	**42,087**	**57.38**	31,702	30.58
North America	**224,609**	**42.30**	116,009	18.24	**444,743**	**42.68**	286,800	23.50

Sales in North America increased on a dollar and per unit basis for the three and six months ended June 30, 2021 versus the comparable prior periods due to higher benchmark prices across all products, partially offset by lower production volumes.

Royalties

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Canada	**(27,001)**	**(5.43)**	(6,777)	(1.18)	**(48,775)**	**(5.04)**	(23,462)	(2.10)
United States	**(4,754)**	**(13.98)**	(3,836)	(6.28)	**(11,060)**	**(15.08)**	(7,852)	(7.57)
North America	**(31,755)**	**(5.98)**	(10,613)	(1.67)	**(59,835)**	**(5.74)**	(31,314)	(2.57)

Royalties in North America increased on a dollar and per unit basis for the three and six months ended June 30, 2021 versus the comparable prior periods primarily due to higher benchmark prices. Royalties as a percentage of sales for the three and six months ended June 30, 2021 of 14.1% and 13.5% increased versus comparable periods in the prior year primarily due to the effect of higher commodity prices on sliding scale royalties.

Transportation

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Canada	**(9,868)**	**(1.99)**	(10,465)	(1.82)	**(20,104)**	**(2.08)**	(21,603)	(1.93)
United States	**(216)**	**(0.64)**	(469)	(0.77)	**(464)**	**(0.63)**	(469)	(0.45)
North America	**(10,084)**	**(1.90)**	(10,934)	(1.72)	**(20,568)**	**(1.97)**	(22,072)	(1.81)

Transportation expense in North America decreased versus the comparable prior periods primarily due to lower volumes shipped through pipelines, partially offset by increased pipeline tariffs. For the six months ended June 30, 2021, transportation expense in the United States increased on a per unit basis primarily due more volume being shipped via pipeline.

Operating expense

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Canada	**(54,441)**	**(10.95)**	(57,281)	(9.96)	**(107,607)**	**(11.11)**	(121,466)	(10.88)
United States	**(3,389)**	**(9.97)**	(3,765)	(6.17)	**(7,504)**	**(10.23)**	(9,314)	(8.98)
North America	**(57,830)**	**(10.89)**	(61,046)	(9.60)	**(115,111)**	**(11.05)**	(130,780)	(10.72)

Operating expenses in North America decreased on a dollar basis for the three and six months ended June 30, 2021 primarily due to cost reduction initiatives combined with lower production volumes. On a per unit basis, operating expenses increased for the three months ended June 30, 2021 primarily due to lower production volumes and the resulting impact of fixed costs.

International

	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Production [1]				
Crude oil and condensate (bbls/d)	**14,037**	13,471	**14,298**	14,232
Natural gas (mmcf/d)	**83.66**	101.99	**86.62**	104.81
Total production volume (boe/d)	**27,981**	30,472	**28,734**	31,701
Total sales volume (boe/d)	**27,802**	29,201	**27,084**	32,114

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

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**182,570**	**72.16**	77,004	28.98	**330,573**	**67.43**	234,527	40.13
Royalties	**(9,701)**	**(3.83)**	(5,739)	(2.16)	**(18,067)**	**(3.69)**	(16,163)	(2.77)
Transportation	**(11,750)**	**(4.64)**	(5,431)	(2.04)	**(18,287)**	**(3.73)**	(11,623)	(1.99)
Operating	**(41,907)**	**(16.56)**	(38,129)	(14.35)	**(80,867)**	**(16.50)**	(89,533)	(15.32)
General and administration	**(6,607)**	**(2.61)**	(7,238)	(2.72)	**(11,489)**	**(2.34)**	(15,617)	(2.67)
Corporate income tax recovery (expense)	**(492)**	**(0.19)**	(55)	(0.02)	**1,067**	**0.22**	(397)	(0.07)
PRRT	**(1,459)**	**(0.58)**	(3,219)	(1.21)	**(2,873)**	**(0.59)**	(12,475)	(2.13)
Fund flows from operations	**110,654**	**43.74**	17,193	6.47	**200,057**	**40.81**	88,719	15.18
Capital expenditures	**(40,329)**		(18,295)		**(64,579)**		(54,073)	
Free cash flow	**70,325**		(1,102)		**135,478**		34,646	

Production from our International assets averaged 27,981 boe/d in Q2 2021, representing a decrease of 8% year-over-year primarily due to natural decline and reduced capital activity.

In Europe, during the second quarter, we drilled one (1.0 net) natural gas well in the Netherlands from the Rotliegend Slochteren formation. The well was completed in June 2021 and we expect to bring production on in Q3 2021. Subsequent to Q2 2021, we began inline testing of the Rotliegend formation on the Blesdijke natural gas well (0.5 net) drilled in Q1 2021 and achieved initial rates up to 7.0 mmcf/d. We plan on conducting further testing in Q3 2021 and expect to bring the well onstream later in the year.

Sales

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Australia	**31,256**	**97.49**	28,772	61.91	**58,638**	**96.07**	80,767	80.55
France	**68,108**	**81.80**	23,329	43.94	**119,637**	**79.75**	80,118	54.85
Netherlands	**32,555**	**56.23**	10,654	14.69	**61,106**	**50.52**	30,257	20.63
Germany	**20,274**	**60.36**	6,553	21.33	**33,369**	**55.73**	17,022	27.95
Ireland	**30,188**	**65.93**	7,268	12.43	**57,256**	**59.03**	24,856	20.50
Central and Eastern Europe	**189**	**45.15**	428	9.74	**567**	**41.77**	1,507	16.11
International	**182,570**	**72.16**	77,004	49.42	**330,573**	**67.43**	234,527	40.13

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 2021	Q2 2020	YTD 2021	YTD 2020
Australia	**3,523**	5,107	**3,372**	5,509
France	**9,149**	5,835	**8,288**	8,026
Germany	**1,091**	1,172	**890**	1,023
International	**13,763**	12,114	**12,550**	14,558

Sales increased on a dollar and per boe basis for the three and six months ended June 30, 2021 versus the prior year comparable periods primarily due to higher realized prices across most business units driven by higher commodity prices over the same periods. This higher pricing was partially offset by lower sales volumes in the Netherlands, Ireland and Central Eastern Europe driven by natural decline and downtime in Australia due to a shutdown, and the timing of liftings in France and Australia.

Royalties

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
France	**(9,167)**	**(11.01)**	(4,711)	(8.87)	**(16,403)**	**(10.93)**	(13,751)	(9.41)
Netherlands	**(128)**	**(0.22)**	(55)	(0.08)	**(225)**	**(0.19)**	(198)	(0.14)
Germany	**(367)**	**(1.09)**	(795)	(2.59)	**(1,322)**	**(2.21)**	(1,737)	(2.85)
Central and Eastern Europe	**(39)**	**(9.32)**	(178)	(4.05)	**(117)**	**(8.62)**	(477)	(5.10)
International	**(9,701)**	**(3.83)**	(5,739)	(3.27)	**(18,067)**	**(3.69)**	(16,163)	(2.77)

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

Royalties increased in our International core region for the three and six months ended June 30, 2021 versus the prior year comparable periods mainly due to higher production and sales in France. Royalties as a percentage of sales for the three and six months ended June 30, 2021 of 5.3% and 5.5% decreased versus the prior year comparable periods of 7.5% and 6.9%. This is primarily due to the impact of RCDM royalties in France, which are levied on units of production and not subject to changes in commodity prices.

Transportation

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
France	**(9,118)**	**(10.95)**	(2,747)	(5.17)	**(13,523)**	**(9.01)**	(6,472)	(4.43)
Germany	**(1,554)**	**(4.63)**	(1,505)	(4.90)	**(2,575)**	**(4.30)**	(2,827)	(4.64)
Ireland	**(1,078)**	**(2.35)**	(1,179)	(2.02)	**(2,189)**	**(2.26)**	(2,324)	(1.92)
International	**(11,750)**	**(4.64)**	(5,431)	(1.94)	**(18,287)**	**(3.73)**	(11,623)	(1.99)

Transportation expense increased for the three and six months ended June 30, 2021 versus the comparable prior year periods. This increase was primarily in France relating to higher volumes in 2021 and the use of incremental trucking in the Paris Basin following the conversion of the Grandpuits refinery.

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

Operating expense

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Australia	**(10,408)**	**(32.46)**	(10,659)	(22.93)	**(20,146)**	**(33.01)**	(28,032)	(27.96)
France	**(12,591)**	**(15.12)**	(10,016)	(18.86)	**(24,382)**	**(16.25)**	(25,915)	(17.74)
Netherlands	**(7,895)**	**(13.64)**	(7,526)	(10.37)	**(15,306)**	**(12.66)**	(16,441)	(11.21)
Germany	**(6,807)**	**(20.27)**	(5,912)	(19.24)	**(13,109)**	**(21.89)**	(10,827)	(17.78)
Ireland	**(4,157)**	**(9.08)**	(3,852)	(6.59)	**(7,814)**	**(8.06)**	(8,064)	(6.65)
Central and Eastern Europe	**(49)**	**(11.71)**	(164)	(3.73)	**(110)**	**(8.10)**	(254)	(2.72)
International	**(41,907)**	**(16.56)**	(38,129)	(14.35)	**(80,867)**	**(16.50)**	(89,533)	(15.32)

Operating expenses on a dollar and per boe basis increased for Q2 2021 versus Q2 2020. This increase primarily resulted from higher inventory draws in France where operating expenses are deferred on the balance sheet until crude oil is sold at which point the related expenses are recognized into income.

For the six months ended June 30, 2021 versus the comparable prior year period, operating expenses decreased mainly due to a larger inventory build in Australia in 2021. Operating expenses on a per boe basis for the same periods increased mainly due to timing of inventory draws and higher facility costs in Germany combined with natural declines in Ireland and the Netherlands.

Consolidated Financial Performance Review

Fund flows from operations

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**407,179**	**51.93**	193,013	21.40	**775,316**	**50.60**	521,327	28.88
Royalties	**(41,456)**	**(5.29)**	(16,352)	(1.81)	**(77,902)**	**(5.08)**	(47,477)	(2.63)
Transportation	**(21,834)**	**(2.78)**	(16,365)	(1.81)	**(38,855)**	**(2.54)**	(33,695)	(1.87)
Operating	**(99,737)**	**(12.72)**	(99,175)	(11.00)	**(195,978)**	**(12.79)**	(220,313)	(12.21)
General and administration	**(11,432)**	**(1.46)**	(16,912)	(1.88)	**(23,162)**	**(1.51)**	(30,229)	(1.67)
Corporate income tax recovery (expense)	**(691)**	**(0.09)**	(158)	(0.02)	**654**	**0.04**	(732)	(0.04)
PRRT	**(1,459)**	**(0.19)**	(3,219)	(0.36)	**(2,873)**	**(0.19)**	(12,475)	(0.69)
Interest expense	**(18,862)**	**(2.41)**	(17,887)	(1.98)	**(38,097)**	**(2.49)**	(37,869)	(2.10)
Realized (loss) gain on derivatives	**(39,574)**	**(5.05)**	54,704	6.07	**(65,207)**	**(4.26)**	104,123	5.77
Realized foreign exchange (loss) gain	**(1,958)**	**(0.25)**	3,972	0.44	**(7,139)**	**(0.47)**	12,495	0.69
Realized other income (expense)	**2,766**	**0.35**	231	0.03	**8,236**	**0.54**	(3,078)	(0.17)
Fund flows from operations	**172,942**	**22.04**	81,852	9.08	**334,993**	**21.85**	252,077	13.96

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

General and administration

- General and administration expense decreased for the three and six months ended June 30, 2021 versus the comparable prior year periods primarily due to work-force reductions made in 2020.

PRRT and corporate income taxes

- PRRT decreased for the three months ended June 30, 2021 versus the prior year comparable periods due to higher sales in Australia which were offset by increased capital expenditures, and the six months ended June 30, 2021 versus the prior year comparable periods due to lower sales in Australia.
- Corporate income taxes for the three and six months ended June 30, 2021 versus the prior year comparable periods remained relatively consistent.

Interest expense

- Interest expense remained relatively consistent for the three and six months ended June 30, 2021 versus the prior year comparable periods.

Realized gain or loss on derivatives

- Realized gains on derivatives in 2020 relate to receipts for European natural gas and crude oil hedges. For the three and six months ended June 30, 2021, we recorded realized losses on our crude oil and natural gas prices due to higher commodity pricing compared to the strike prices on our hedges.
- A listing of derivative positions as at June 30, 2021 is included in "Supplemental Table 2" of this MD&A.

Realized other income

- Realized other income for the three and six months ended June 30, 2021 primarily relates to amounts for funding under the Saskatchewan Accelerated Site Closure program to complete abandonment and reclamation on inactive oil and gas wells and facilities. Realized other expense for the prior year comparable period relates primarily to amounts uncertain to be received pursuant to a negotiated settlement of a legal matter.

Net earnings

The following table shows a reconciliation from fund flows from operations to net earnings (loss):

($M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Fund flows from operations	**172,942**	81,852	**334,993**	252,077
Equity based compensation	**(10,536)**	(9,164)	**(27,076)**	(22,161)
Unrealized (loss) gain on derivative instruments	**(79,408)**	(3,771)	**(73,966)**	5,545
Unrealized foreign exchange loss	**(18,298)**	(7,410)	**(44,208)**	(17,392)
Accretion	**(10,863)**	(7,288)	**(21,370)**	(17,026)
Depletion and depreciation	**(149,651)**	(106,707)	**(255,664)**	(264,514)
Deferred tax (expense) recovery	**(63,526)**	51,126	**(234,754)**	308,668
Gain on business combinations	**17,198**	—	**17,198**	—
Impairment reversal (expense)	**593,606**	(69,713)	**1,256,472**	(1,634,567)
Unrealized other expense	**(190)**	(215)	**(387)**	(424)
Net earnings (loss)	**451,274**	(71,290)	**951,238**	(1,389,794)

Fluctuations in net earnings 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 resulting from business combinations or charges resulting from impairment or impairment reversals.

Equity based compensation

Equity based compensation expense relates primarily to non-cash compensation expense attributable to long-term incentives granted to directors, officers, and employees under security-based arrangements. Equity based compensation expense increased for the three and six months ended June 30, 2021 versus the prior year comparable periods due to the higher value of VIP awards outstanding in the current periods.

Unrealized gain or loss on derivative instruments

Unrealized gain or loss on derivative instruments arise 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 hedge 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, 2021, we recognized a net unrealized loss on derivative instruments of $79.4 million. This consists of unrealized losses of $111.8 million on our European natural gas commodity derivative instruments and $6.4 million on our North American natural gas commodity derivative instruments. These unrealized losses are partially offset by unrealized gains of $22.8 million on our USD-to-CAD foreign exchange swaps, $9.5 million on our crude oil commodity derivative instruments and $6.5 million on our equity swaps.

For the six months ended June 30, 2021, we recognized a net unrealized loss on derivative instruments of $74.0 million. This consists of unrealized losses of $124.9 million on our European natural gas commodity derivative instruments, $10.3 million on our North American natural gas commodity derivative instruments and $1.0 million on our crude oil commodity derivative instruments. These unrealized losses are partially offset by unrealized gains of $42.8 million on our USD-to-CAD foreign exchange swaps and $19.4 million on our equity swaps.

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 2021, unrealized foreign exchange gains and losses primarily resulted from:

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

- 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 (discussed further below).
- The translation of our USD denominated senior unsecured notes prior to June 12, 2019 and from May 5, 2020 onward. During the period between June 12, 2019 and May 5, 2020 the USD senior notes were hedged by a USD-to-CAD cross currency interest rate swap. Subsequent to the termination of these instruments, amounts previously recognized in the hedge accounting reserve will be recognized into earnings through unrealized foreign exchange loss over the period of the hedged cash flows.

For the three months ended June 30, 2021, we recognized a net unrealized foreign exchange loss of $18.3 million due to unrealized losses of $16.8 million on intercompany loans due to the Euro weakening 1.0% against the Canadian dollar in Q2 2021 and $10.0 million on our USD borrowings from our revolving credit facility. These were partially offset by the impact of the US dollar weakening 2.3% against the Canadian dollar in Q2 2021 resulting in an unrealized gain of $8.5 million on our senior unsecured notes.

For the six months ended June 30, 2021, we recognized a net unrealized foreign exchange loss of $44.2 million. This was due to unrealized losses of $33.0 million on our USD borrowings from our revolving credit facility and $24.3 million on intercompany loans due to the Euro weakening 5.9% against the Canadian dollar. These were partially offset by the impact of the US dollar weakening 3.4% against the Canadian dollar resulting in an unrealized gain of $13.1 million on our senior unsecured notes.

As at June 30, 2021, a $0.01 appreciation of the Euro against the Canadian dollar would result in a $0.7 million increase to net earnings as a result of an unrealized gain on foreign exchange. In contrast, a $0.01 appreciation of the US dollar against the Canadian dollar would result in a $3.0 million decrease to net earnings as a result of an unrealized loss on foreign exchange.

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, 2021 versus the comparable prior year periods accretion expense increased primarily due to additional obligations recognized at the end of 2020 partially offset by the weakening of the Euro against the Canadian dollar.

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, 2021 of $19.09 and $16.69 increased from $11.83 and $14.65 in the prior year comparable periods primarily due to impairment reversals recorded in Q1 2021.

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, 2021, deferred tax expense was recognized of $63.5 million and $234.8 million respectively compared to a deferred tax recovery of $51.1 million and $308.7 million for the prior year comparable periods primarily due to impairment reversals in 2021, partially offset by the recognition of a portion of non-expiring tax loss pools in Ireland that are expected to be utilized due to an increase in forecast commodity prices.

Impairment

Impairment losses are recognized when indicators of impairment arise and the carrying amount of a cash generating unit ("CGU") exceeds its recoverable amount, determined as the higher of fair value less costs of disposal or value-in-use.

In the second quarter of 2021, indicators of impairment reversal were present in our Alberta, Saskatchewan, Germany, Ireland and United States CGUs due to an increase and stabilization in forecast oil and gas prices. As a result of the indicators of impairment reversal, the Company performed impairment reversal calculations on the identified CGUs and the recoverable amounts were determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 12.0%. Based on the results of the impairment reversal calculations completed, recoverable amounts were determined to be greater than the carrying values of the CGUs tested and $460.4 million (net of $133.2 million deferred income tax expense) of impairment reversal was recorded.

In the first quarter of 2021, indicators of impairment reversal were present in our Australia, Alberta, Saskatchewan, and United States CGUs due to an increase and stabilization in forecast crude oil prices versus 2020 when impairment charges were taken. As a result of the indicators of impairment reversal, the Company performed impairment reversal tests on the identified CGUs and the recoverable amounts were determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 12.0%. Based on the results of the impairment reversal calculations completed, recoverable amounts were determined to be greater than the carrying values of the CGUs tested and $492.2 million (net of $170.7 million deferred income tax expense) of impairment reversal was recorded.

In the first quarter of 2020, indicators of impairment were present due to global commodity price forecasts deteriorating from decreases in demand and an increase of supply around the world. As a result of the indicators of impairment, the Company performed impairment tests across all CGUs. The recoverable amounts were determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 11.5%. Based on the results of the impairment calculations completed, the Company recognized non-cash impairment charges of $1.2 billion (net of $0.4 billion income tax recovery).

In the second quarter of 2020, indicators of impairment were present due to the Company’s market capitalization falling below the carrying value of its net assets as at June 30, 2020. As a result of the indicators of impairment, the Company performed an impairment test. The recoverable amount was determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 11.5%. Based on the results of the impairment calculations completed, the Company recognized non-cash impairment charges of $53.1 million (net of $16.6 million income tax recovery).

Inputs used in the measurement of capital assets are not based on observable market data and fall within level 3 of the fair value hierarchy.

Gain on business combinations

A gain on business combination is recognized when the total consideration paid in a business combination is less than the fair value of the net assets acquired. For the three months ended June 30, 2021, a gain of $17.2 million was recognized on our purchase of assets in Germany.

Financial Position Review

Balance sheet strategy

We regularly review whether our forecast of fund flows from operations is sufficient to finance planned capital expenditures, 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, or with debt (including borrowing using the unutilized capacity of our existing revolving credit facility). We have a long-term goal of achieving and maintaining a ratio of net debt to fund flows from operations of less than 1.5.

As at June 30, 2021, we have a ratio of net debt to fund flows from operations of 3.43. We will continue to monitor for changes in forecasted fund flows from operations and, as appropriate, will adjust our exploration and development capital plans (and associated growth targets) to minimize any further increase to debt. As commodity prices improve, we intend to strengthen our balance sheet through the reduction of debt.

Net debt

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

	As at	
($M)	**Jun 30, 2021**	**Dec 31, 2020**
Long-term debt	**1,769,866**	1,933,848
Current liabilities	**528,180**	433,128
Current assets	**(292,774)**	(260,993)
Net debt	**2,005,272**	2,105,983
Ratio of net debt to four quarter trailing fund flows from operations	**3.43**	4.19

As at June 30, 2021, net debt decreased to $2.0 billion (December 31, 2020 - $2.1 billion) primarily as a result of free cash flow generated for the six months ended June 30, 2021 of $172.5 million, partially offset by timing of payments and increased current derivative liabilities due to increased commodity prices. We will draw on unutilized capacity of the revolving credit facility to fund working capital deficiencies. The ratio of net debt to four quarter trailing fund flows from operations decreased to 3.43 (December 31, 2020 - 4.19) mainly due to the decrease in net debt combined with higher four quarter trailing fund flows from operations.

Long-term debt

The balances recognized on our balance sheet are as follows:

	As at	
($M)	**Jun 30, 2021**	**Dec 31, 2020**
Revolving credit facility	**1,403,877**	1,555,215
Senior unsecured notes	**365,989**	378,633
Long-term debt	**1,769,866**	1,933,848

Revolving Credit Facility

As at June 30, 2021, Vermilion had in place a bank revolving credit facility maturing May 31, 2024 with terms and outstanding positions as follows:

	As at	
($M)	**Jun 30, 2021**	**Dec 31, 2020**
Total facility amount	**2,100,000**	2,100,000
Amount drawn	**(1,403,877)**	(1,555,215)
Letters of credit outstanding	**(15,489)**	(23,210)
Unutilized capacity	**680,634**	521,575

As at June 30, 2021, the revolving credit facility was subject to the following financial covenants:

		As at	
Financial covenant	**Limit**	**Jun 30, 2021**	**Dec 31, 2020**
Consolidated total debt to consolidated EBITDA	Less than 4.0	**2.76**	3.48
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	**2.19**	2.82
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	**9.09**	8.12

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

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

In addition, our revolving credit facility has provisions relating to our liability management ratings in Alberta and Saskatchewan whereby if our security adjusted liability management ratings fall below specified limits in a province, a portion of the asset retirement obligations are included in the definitions of consolidated total debt and consolidated total senior debt. An event of default occurs if our security adjusted liability management ratings breach additional lower limits for a period greater than 90 days. As of June 30, 2021, Vermilion's liability management ratings were higher than the specified levels, and as such, no amounts relating to asset retirement obligations were included in the calculation of consolidated total debt and consolidated total senior debt.

Senior Unsecured Notes

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

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

Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth in the following table plus any accrued and unpaid interest, if redeemed during the twelve-month period beginning on March 15 of each of the years indicated below:

Year	Redemption price
2021	102.813 %
2022	101.406 %
2023 and thereafter	100.000 %

Shareholders' capital

The following table outlines our dividend payment history:

Date	Monthly dividend per unit or share
January 2003 to December 2007	$0.170
January 2008 to December 2012	$0.190
January 2013 to December 2013	$0.200
January 2014 to March 2018	$0.215
April 2018 to February 2020	$0.230
March 2020	$0.115

In April 2020, we suspended our monthly dividend to strengthen the financial position of the Company. Our ability to restore a dividend will be dependent upon stronger commodity prices combined with a balance sheet that reflects the Company's ability to sustain such dividend over the long-term.

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount ($M)
Balance at December 31, 2020	**158,724**	**4,181,160**
Vesting of equity based awards	**2,113**	**44,852**
Equity based compensation	**838**	**7,693**
Share-settled dividends on vested equity based awards	**218**	**1,920**
Balance at June 30, 2021	**161,893**	**4,235,625**

As at June 30, 2021, there were approximately 7.1 million equity based compensation awards outstanding. As at August 13, 2021, there were approximately 162.0 million common shares issued and outstanding.

Asset Retirement Obligations

As at June 30, 2021, asset retirement obligations were $809.2 million compared to $467.7 million as at December 31, 2020. The increase in asset retirement obligations is primarily attributable to a decrease in the credit-adjusted risk-free rate from December 31, 2020 to June 30, 2021. This increase was partially offset by the Euro weakening against the Canadian dollar and obligations settled.

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 as the yield to maturity on its senior unsecured notes 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, 2021	Dec 31, 2020	Change
Credit spread added to below noted risk-free rates	**4.7 %**	9.5 %	(4.8)%
Country specific risk-free rate			
Canada	**1.9 %**	1.2 %	0.7 %
United States	**2.1 %**	1.6 %	0.5 %
France	**0.8 %**	0.3 %	0.5 %
Netherlands	**(0.3)%**	(0.6)%	0.3 %
Germany	**0.3 %**	(0.2)%	0.5 %
Ireland	**0.5 %**	(0.1)%	0.6 %
Australia	**1.8 %**	1.3 %	0.5 %

Risks and Uncertainties

Vermilion is exposed to various market and operational risks. For a discussion of these risks, please see Vermilion's MD&A and Annual Information Form, each for the year ended December 31, 2020 available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

Critical Accounting Estimates

The preparation of financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of any possible contingencies. These estimates and assumptions are developed based on the best available information which management believed to be reasonable at the time such estimates and assumptions were made. As such, these assumptions are uncertain at the time estimates are made and could change, resulting in a material impact on Vermilion's consolidated financial statements. Estimates are reviewed by management on an ongoing basis and as a result may change from period to period due to the availability of new information or changes in circumstances. Additionally, as a result of the unique circumstances of each jurisdiction that Vermilion operates in, the critical accounting estimates may affect one or more jurisdictions. There have been no material changes to our critical accounting estimates used in applying accounting policies for the six months ended June 30, 2021. 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, 2020, available on SEDAR at www.sedar.com 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

Other than Vermilion's response to COVID-19, 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, its internal control over financial reporting.

As a result of COVID-19, our global workforce shifted to a primarily work from home environment beginning in March 2020. This change to remote working was rapid and included both our employees as well as a large extended workforce across all regions in which we operate. While pre-existing controls were not specifically designed to operate in our current work from home operating environment, we believe that our internal controls over financial reporting continue to be effective. We took precautionary actions to re-evaluate and refine our financial reporting process to provide reasonable assurance that we could report our financial results accurately and timely.

Recently Adopted Accounting Pronouncements

Vermilion did not adopt any new accounting pronouncements as at June 30, 2021.

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, 2021, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based on this evaluation, the President, for this specific purpose of acting in the capacity of Chief Executive Officer, and Chief Financial Officer have concluded and certified that our disclosure controls and procedures are effective.

Supplemental Table 1: Netbacks

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

	Q2 2021			YTD 2021			Q2 2020	YTD 2020
	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	62.13	2.71	**41.62**	59.63	3.15	**41.57**	17.41	22.84
Royalties	(9.17)	(0.14)	**(5.43)**	(8.27)	(0.16)	**(5.04)**	(1.18)	(2.10)
Transportation	(2.61)	(0.20)	**(1.99)**	(2.73)	(0.21)	**(2.08)**	(1.82)	(1.93)
Operating	(13.28)	(1.35)	**(10.95)**	(13.58)	(1.34)	**(11.11)**	(9.96)	(10.88)
Operating netback	37.07	1.02	**23.25**	35.05	1.44	**23.34**	4.45	7.93
General and administration			**(1.20)**			**(1.07)**	(1.51)	(1.03)
Fund flows from operations netback			**22.05**			**22.27**	2.94	6.90
United States								
Sales	63.65	2.87	**52.24**	60.95	7.63	**57.38**	26.00	30.58
Royalties	(16.55)	(1.02)	**(13.98)**	(15.72)	(2.16)	**(15.08)**	(6.28)	(7.57)
Transportation	(0.84)	—	**(0.64)**	(0.83)	—	**(0.63)**	(0.77)	(0.45)
Operating	(10.02)	(1.64)	**(9.97)**	(10.31)	(1.66)	**(10.23)**	(6.17)	(8.98)
Operating netback	36.24	0.21	**27.65**	34.09	3.81	**31.44**	12.78	13.58
General and administration			**(2.13)**			**(2.21)**	(2.94)	(3.63)
Fund flows from operations netback			**25.52**			**29.23**	9.84	9.95
France								
Sales	81.80	—	**81.80**	79.75	—	**79.75**	43.94	54.85
Royalties	(11.01)	—	**(11.01)**	(10.93)	—	**(10.93)**	(8.87)	(9.41)
Transportation	(10.95)	—	**(10.95)**	(9.01)	—	**(9.01)**	(5.17)	(4.43)
Operating	(15.12)	—	**(15.12)**	(16.25)	—	**(16.25)**	(18.86)	(17.74)
Operating netback	44.72	—	**44.72**	43.56	—	**43.56**	11.04	23.27
General and administration			**(3.86)**			**(3.75)**	(6.59)	(4.76)
Current income taxes			**—**			**—**	—	—
Fund flows from operations netback			**40.86**			**39.81**	4.45	18.51
Netherlands								
Sales	67.76	9.34	**56.23**	52.53	8.42	**50.52**	14.69	20.63
Royalties	—	(0.04)	**(0.22)**	—	(0.03)	**(0.19)**	(0.08)	(0.14)
Operating	—	(2.31)	**(13.64)**	—	(2.14)	**(12.66)**	(10.37)	(11.21)
Operating netback	67.76	6.99	**42.37**	52.53	6.25	**37.67**	4.24	9.28
General and administration			**(0.19)**			**(0.31)**	(0.29)	(0.52)
Current income taxes			**(4.08)**			**(1.95)**	0.35	0.18
Fund flows from operations netback			**38.10**			**35.41**	4.30	8.94
Germany								
Sales	78.00	8.83	**60.36**	75.58	8.07	**55.73**	21.33	27.95
Royalties	(1.24)	(0.17)	**(1.09)**	(0.95)	(0.45)	**(2.21)**	(2.59)	(2.85)
Transportation	(10.82)	(0.34)	**(4.63)**	(9.68)	(0.39)	**(4.30)**	(4.90)	(4.64)
Operating	(23.71)	(3.14)	**(20.27)**	(23.60)	(3.54)	**(21.89)**	(19.24)	(17.78)
Operating netback	42.23	5.18	**34.37**	41.35	3.69	**27.33**	(5.40)	2.68
General and administration			**(4.34)**			**(4.31)**	(4.28)	(5.02)
Fund flows from operations netback			**30.03**			**23.02**	(9.68)	(2.34)
Ireland								
Sales	—	10.98	**65.93**	—	9.83	**59.03**	12.43	20.50
Transportation	—	(0.39)	**(2.35)**	—	(0.38)	**(2.26)**	(2.02)	(1.92)
Operating	—	(1.51)	**(9.08)**	—	(1.34)	**(8.06)**	(6.59)	(6.65)
Operating netback	—	9.08	**54.50**	—	8.11	**48.71**	3.82	11.93
General and administration			**(0.05)**			**0.71**	0.18	(0.23)
Fund flows from operations netback			**54.45**			**49.42**	4.00	11.70

	Q2 2021 Liquids $/bbl	Q2 2021 Natural Gas $/mcf	Q2 2021 Total $/boe	YTD 2021 Liquids $/bbl	YTD 2021 Natural Gas $/mcf	YTD 2021 Total $/boe	Q2 2020 Total $/boe	YTD 2020 Total $/boe
Australia								
Sales	97.49	—	**97.49**	96.07	—	**96.07**	61.91	80.55
Operating	(32.46)	—	**(32.46)**	(33.01)	—	**(33.01)**	(22.93)	(27.96)
PRRT [(1)]	(4.55)	—	**(4.55)**	(4.71)	—	**(4.71)**	(6.93)	(12.44)
Operating netback	60.48	—	**60.48**	58.35	—	**58.35**	32.05	40.15
General and administration			**(2.35)**			**(2.42)**	(1.91)	(1.76)
Current income taxes			**5.84**			**5.62**	(0.67)	(0.65)
Fund flows from operations netback			**63.97**			**61.55**	29.47	37.74
Total Company								
Sales	69.11	5.24	**51.93**	66.38	5.37	**50.60**	21.40	28.88
Realized hedging (loss) gain	(4.67)	(0.92)	**(5.05)**	(4.67)	(0.63)	**(4.26)**	6.07	5.77
Royalties	(9.08)	(0.13)	**(5.29)**	(8.49)	(0.19)	**(5.08)**	(1.81)	(2.63)
Transportation	(4.12)	(0.20)	**(2.78)**	(3.67)	(0.20)	**(2.54)**	(1.81)	(1.87)
Operating	(15.10)	(1.65)	**(12.72)**	(15.45)	(1.62)	**(12.79)**	(11.00)	(12.21)
PRRT [(1)]	(0.34)	—	**(0.19)**	(0.35)	—	**(0.19)**	(0.36)	(0.69)
Operating netback	35.80	2.34	**25.90**	33.75	2.73	**25.74**	12.49	17.25
General and administration			**(1.46)**			**(1.51)**	(1.88)	(1.67)
Interest expense			**(2.41)**			**(2.49)**	(1.98)	(2.10)
Realized foreign exchange loss			**(0.25)**			**(0.47)**	0.44	0.69
Other income			**0.35**			**0.54**	0.03	(0.17)
Corporate income taxes			**(0.09)**			**0.04**	(0.02)	(0.04)
Fund flows from operations netback			**22.04**			**21.85**	9.08	13.96

(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, 2021:

	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 2021	bbl	USD	500	55.00	500	63.25	500	47.50	500	52.00	—	—
Q4 2021	bbl	USD	—	—	—	—	—	—	500	52.00	—	—
Q1 2022	bbl	USD	—	—	—	—	—	—	500	52.00	—	—
WTI												
Q3 2021	bbl	USD	1,500	57.50	1,500	73.67	1,500	48.33	—	—	—	—
Q4 2021	bbl	USD	1,000	60.00	1,000	80.50	1,000	50.00	—	—	—	—
Q1 2022	bbl	USD	500	60.00	500	70.00	500	45.00	—	—	—	—
Q2 2022	bbl	USD	500	60.00	500	70.00	500	45.00	—	—	—	—
AECO												
Q3 2021	mcf	CAD	—	—	—	—	—	—	9,478	2.12	—	—
Q4 2021	mcf	CAD	—	—	—	—	—	—	3,194	2.12	—	—
AECO Basis (AECO less NYMEX Henry Hub)												
Q3 2021	mcf	USD	—	—	—	—	—	—	45,000	(1.08)	—	—
Q4 2021	mcf	USD	—	—	—	—	—	—	35,054	(1.09)	—	—
Q1 2022	mcf	USD	—	—	—	—	—	—	30,000	(1.10)	—	—
Q2 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)	—	—
Q3 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)	—	—
Q4 2022	mcf	USD	—	—	—	—	—	—	11,793	(1.09)	—	—
NYMEX Henry Hub												
Q3 2021	mcf	USD	35,000	2.72	35,000	3.12	—	—	28,500	2.83	—	—
Q4 2021	mcf	USD	31,685	2.72	31,685	3.12	—	—	21,870	2.78	—	—
Ventura Basis (Ventura less NYMEX Henry Hub)												
Q3 2021	mcf	USD	—	—	—	—	—	—	—	—	10,000	0.05
Q4 2021	mcf	USD	—	—	—	—	—	—	—	—	3,370	0.05
Conway Propane											—	—
Q3 2021	bbl	USD	—	—	—	—	—	—	500	50% WTI	—	—
Q4 2021	bbl	USD	—	—	—	—	—	—	168	50% WTI	—	—

	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
NBP												
Q3 2021	mcf	EUR	49,135	5.37	49,135	5.62	49,135	3.87	2,457	4.69	—	—
Q4 2021	mcf	EUR	58,962	5.37	58,962	5.56	58,962	3.88	2,457	4.69	—	—
Q1 2022	mcf	EUR	34,394	5.18	34,394	5.95	34,394	3.63	4,913	4.91	—	—
Q2 2022	mcf	EUR	27,024	5.07	27,024	5.73	27,024	3.50	4,913	4.91	—	—
Q3 2022	mcf	EUR	17,197	5.00	17,197	5.79	17,197	3.56	4,913	4.91	—	—
Q4 2022	mcf	EUR	17,197	5.00	17,197	5.78	17,197	3.56	4,913	4.91	—	—
Q1 2023	mcf	EUR	9,827	5.02	9,827	5.72	9,827	3.59	—	—	—	—
Q2 2023	mcf	EUR	2,457	5.86	2,457	7.62	2,457	4.40	—	—	—	—
TTF												
Q3 2021	mcf	EUR	2,457	4.25	2,457	4.07	2,457	2.93	—	—	—	—
Q1 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q2 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q3 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q4 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q1 2023	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—

VET Equity Swaps		Initial Share Price		Share Volume
Swap	Jan 2020 - Apr 2023	20.9788	CAD	2,250,000
Swap	Jan 2020 - Apr 2023	22.4587	CAD	1,500,000

Foreign Currency Swaps		Notional Amount		Notional Amount		Average Rate
Swap	July 2021	1,131,404,500	USD	1,400,000,000	CAD	1.2374

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Drilling and development	**77,703**	42,383	**157,215**	269,816
Exploration and evaluation	**1,473**	(109)	**5,324**	6,162
Capital expenditures	**79,176**	42,274	**162,539**	275,978
Acquisitions	**12,196**	2,932	12,589	14,269
Contingent consideration	**330**	—	330	—
Long-term debt net of working capital assumed	**(7)**	—	(7)	—
Acquisitions	**11,859**	2,932	12,252	14,269

By category ($M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Drilling, completion, new well equip and tie-in, workovers and recompletions	**47,453**	21,954	**116,235**	230,118
Production equipment and facilities	**24,859**	15,190	**36,890**	32,817
Seismic, studies, land and other	**6,864**	5,130	**9,414**	13,043
Capital expenditures	**79,176**	42,274	**162,539**	275,978
Acquisitions	**11,859**	2,932	**12,252**	14,269
Total capital expenditures and acquisitions	**91,035**	45,206	**174,791**	290,247

Capital expenditures by country ($M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Canada	**20,210**	9,785	**74,531**	162,362
United States	**18,637**	14,194	**23,429**	59,543
France	**8,913**	5,603	**15,792**	16,860
Netherlands	**7,683**	2,638	**11,816**	5,135
Germany	**3,607**	3,345	**6,106**	11,134
Ireland	**172**	704	**238**	684
Australia	**13,118**	4,200	**19,957**	16,202
Central and Eastern Europe	**6,836**	1,805	**10,670**	4,058
Total capital expenditures	**79,176**	42,274	**162,539**	275,978

Acquisitions by country ($M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Canada	**308**	260	**358**	5,699
United States	**—**	749	**—**	6,607
France	**—**	—	**—**	—
Netherlands	**—**	—	**—**	—
Germany	**11,551**	564	**11,894**	583
Ireland	**—**	—	**—**	—
Australia	**—**	—	**—**	—
Central and Eastern Europe	**—**	1,359	**—**	1,380
Total acquisitions	**11,859**	2,932	**12,252**	14,269

Supplemental Table 4: Production

	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18
Canada												
Light and medium crude oil (bbls/d)	**16,868**	17,767	19,301	19,847	22,545	22,767	23,259	23,610	23,973	25,067	25,640	24,602
Condensate [(1)] (bbls/d)	**5,558**	4,556	4,662	5,200	5,047	4,634	4,140	4,072	4,872	4,096	3,918	3,875
Other NGLs [(1)] (bbls/d)	**7,767**	7,016	7,334	8,350	8,248	6,943	7,005	6,632	7,352	6,968	6,816	6,126
NGLs (bbls/d)	**13,325**	11,572	11,996	13,550	13,295	11,577	11,145	10,704	12,224	11,064	10,734	10,001
Conventional natural gas (mmcf/d)	**146.55**	138.41	135.27	155.15	164.08	151.16	145.14	145.14	151.87	151.37	146.65	136.77
Total (boe/d)	**54,618**	52,407	53,840	59,256	63,187	59,537	58,593	58,504	61,507	61,360	60,814	57,397
United States												
Light and medium crude oil (bbls/d)	**1,888**	2,322	2,495	3,243	3,971	2,481	3,149	2,717	2,421	1,750	1,582	1,455
Condensate [(1)] (bbls/d)	**2**	—	1	6	6	6	12	4	63	(8)	23	6
Other NGLs [(1)] (bbls/d)	**928**	1,058	1,294	1,158	1,340	1,079	1,156	1,140	754	929	998	714
NGLs (bbls/d)	**930**	1,058	1,295	1,164	1,346	1,085	1,168	1,144	817	921	1,021	720
Conventional natural gas (mmcf/d)	**5.51**	5.95	6.87	7.94	8.35	6.72	8.20	6.38	7.06	5.89	5.65	4.82
Total (boe/d)	**3,736**	4,373	4,934	5,730	6,708	4,685	5,683	4,925	4,414	3,653	3,545	2,979
France												
Light and medium crude oil (bbls/d)	**9,013**	9,062	9,255	9,347	7,046	9,957	10,264	10,347	9,800	11,342	11,317	11,407
Conventional natural gas (mmcf/d)	**—**	—	—	—	—	—	—	—	—	0.77	0.82	—
Total (boe/d)	**9,013**	9,062	9,255	9,347	7,046	9,957	10,264	10,347	9,800	11,470	11,454	11,407
Netherlands												
Light and medium crude oil (bbls/d)	**1**	6	1	—	1	3	4	1	9	—	—	—
Condensate [(1)] (bbls/d)	**95**	92	99	83	86	84	86	81	91	93	112	84
NGLs (bbls/d)	**95**	92	99	83	86	84	86	81	91	93	112	84
Conventional natural gas (mmcf/d)	**37.59**	41.45	42.95	46.09	47.31	48.33	47.99	44.08	52.90	51.51	51.82	44.37
Total (boe/d)	**6,362**	7,006	7,257	7,764	7,972	8,143	8,088	7,429	8,917	8,677	8,749	7,479
Germany												
Light and medium crude oil (bbls/d)	**1,093**	911	960	964	1,039	909	800	845	1,047	978	913	1,019
Conventional natural gas (mmcf/d)	**15.60**	13.40	11.50	11.25	13.23	14.64	15.44	14.54	14.56	16.71	16.94	14.88
Total (boe/d)	**3,694**	3,144	2,876	2,839	3,244	3,349	3,373	3,269	3,474	3,763	3,736	3,498
Ireland												
Conventional natural gas (mmcf/d)	**30.19**	34.14	34.76	35.12	38.57	41.38	42.30	43.21	49.21	51.71	52.03	51.38
Total (boe/d)	**5,031**	5,690	5,793	5,853	6,428	6,896	7,049	7,202	8,201	8,619	8,672	8,563
Australia												
Light and medium crude oil (bbls/d)	**3,835**	4,489	3,781	4,549	5,299	4,041	4,548	5,564	6,689	5,862	4,174	4,704
Total (boe/d)	**3,835**	4,489	3,781	4,549	5,299	4,041	4,548	5,564	6,689	5,862	4,174	4,704
Central and Eastern Europe												
Conventional natural gas (mmcf/d)	**0.28**	0.63	0.67	0.80	2.89	3.27	1.66	—	—	—	2.86	1.17
Total (boe/d)	**46**	104	111	132	483	546	276	—	—	—	477	195
Consolidated												
Light and medium crude oil (bbls/d)	**32,698**	34,556	35,793	37,951	39,899	40,157	42,024	43,084	43,938	45,001	43,625	43,186
Condensate [(1)] (bbls/d)	**5,656**	4,648	4,762	5,289	5,142	4,724	4,237	4,158	5,026	4,181	4,053	3,965
Other NGLs [(1)] (bbls/d)	**8,695**	8,074	8,627	9,509	9,588	8,022	8,160	7,772	8,107	7,897	7,815	6,839
NGLs (bbls/d)	**14,351**	12,722	13,389	14,798	14,730	12,746	12,397	11,930	13,133	12,078	11,868	10,804
Conventional natural gas (mmcf/d)	**235.72**	233.98	232.00	256.34	274.42	265.51	260.72	253.36	275.60	277.96	276.77	253.38
Total (boe/d)	**86,335**	86,276	87,848	95,471	100,366	97,154	97,875	97,239	103,003	103,404	101,621	96,222

	YTD 2021	2020	2019	2018	2017	2016
Canada						
Light and medium crude oil (bbls/d)	**17,315**	21,106	23,971	17,400	6,015	6,657
Condensate [1] (bbls/d)	**5,060**	4,886	4,295	3,754	3,036	2,514
Other NGLs [1] (bbls/d)	**7,393**	7,719	6,988	5,914	4,144	2,552
NGLs (bbls/d)	**12,453**	12,605	11,283	9,668	7,180	5,066
Conventional natural gas (mmcf/d)	**142.50**	151.38	148.35	129.37	97.89	84.29
Total (boe/d)	**53,519**	58,942	59,979	48,630	29,510	25,771
United States						
Light and medium crude oil (bbls/d)	**2,104**	3,046	2,514	1,069	662	393
Condensate [1] (bbls/d)	**1**	5	18	8	4	—
Other NGLs [1] (bbls/d)	**993**	1,218	996	452	50	29
NGLs (bbls/d)	**994**	1,223	1,014	460	54	29
Conventional natural gas (mmcf/d)	**5.73**	7.47	6.89	2.78	0.39	0.21
Total (boe/d)	**4,053**	5,514	4,675	1,992	781	457
France						
Light and medium crude oil (bbls/d)	**9,038**	8,903	10,435	11,362	11,084	11,896
Conventional natural gas (mmcf/d)	**—**	—	0.19	0.21	—	0.44
Total (boe/d)	**9,038**	8,903	10,467	11,396	11,085	11,970
Netherlands						
Light and medium crude oil (bbls/d)	**3**	1	3	—	—	—
Condensate [1] (bbls/d)	**94**	88	88	90	90	88
NGLs (bbls/d)	**94**	88	88	90	90	88
Conventional natural gas (mmcf/d)	**39.51**	46.16	49.10	46.13	40.54	47.82
Total (boe/d)	**6,682**	7,782	8,274	7,779	6,847	8,058
Germany						
Light and medium crude oil (bbls/d)	**1,003**	968	917	1,004	1,060	—
Conventional natural gas (mmcf/d)	**14.51**	12.65	15.31	15.66	19.39	14.90
Total (boe/d)	**3,420**	3,076	3,468	3,614	4,291	2,483
Ireland						
Conventional natural gas (mmcf/d)	**32.15**	37.44	46.57	55.17	58.43	50.89
Total (boe/d)	**5,359**	6,240	7,762	9,195	9,737	8,482
Australia						
Light and medium crude oil (bbls/d)	**4,160**	4,416	5,662	4,494	5,770	6,304
Total (boe/d)	**4,160**	4,416	5,662	4,494	5,770	6,304
Central and Eastern Europe						
Conventional natural gas (mmcf/d)	**0.45**	1.90	0.42	1.02	—	—
Total (boe/d)	**75**	317	70	169	—	—
Consolidated						
Light and medium crude oil (bbls/d)	**33,622**	38,441	43,502	35,329	24,591	25,250
Condensate [1] (bbls/d)	**5,155**	4,980	4,400	3,853	3,130	2,602
Other NGLs [1] (bbls/d)	**8,386**	8,937	7,984	6,366	4,194	2,582
NGLs (bbls/d)	**13,541**	13,917	12,384	10,219	7,324	5,184
Conventional natural gas (mmcf/d)	**234.86**	256.99	266.82	250.33	216.64	198.55
Total (boe/d)	**86,306**	95,190	100,357	87,270	68,021	63,526

(1) 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]

	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18
North America												
Crude oil and condensate (bbls/d)	24,316	24,645	26,459	28,296	31,569	29,888	30,560	30,403	31,329	30,905	31,163	29,938
NGLs (bbls/d)	8,695	8,074	8,628	9,508	9,588	8,022	8,161	7,772	8,106	7,897	7,814	6,840
Natural gas (mmcf/d)	152.06	144.36	142.13	163.09	172.43	157.88	153.34	151.52	158.93	157.26	152.30	141.59
Total (boe/d)	**58,354**	**56,780**	**58,774**	**64,986**	**69,895**	**64,222**	**64,276**	**63,429**	**65,921**	**65,013**	**64,359**	**60,376**
International												
Crude oil and condensate (bbls/d)	14,037	14,560	14,096	14,943	13,471	14,994	15,702	16,838	17,636	18,275	16,516	17,214
Natural gas (mmcf/d)	83.66	89.62	89.86	93.25	101.99	107.63	107.38	101.83	116.67	120.70	124.48	111.79
Total (boe/d)	**27,981**	**29,495**	**29,073**	**30,484**	**30,472**	**32,932**	**33,598**	**33,811**	**37,081**	**38,391**	**37,262**	**35,846**
Consolidated												
Crude oil and condensate (bbls/d)	38,354	39,204	40,555	43,240	45,041	44,881	46,261	47,242	48,964	49,182	47,678	47,151
NGLs (bbls/d)	8,695	8,074	8,627	9,509	9,588	8,022	8,160	7,772	8,107	7,897	7,815	6,839
Natural gas (mmcf/d)	235.72	233.98	232.00	256.34	274.42	265.51	260.72	253.36	275.60	277.96	276.77	253.38
Total (boe/d)	**86,335**	**86,276**	**87,848**	**95,471**	**100,366**	**97,154**	**97,875**	**97,239**	**103,003**	**103,404**	**101,621**	**96,222**

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

Sales volumes

	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18
North America												
Crude oil and condensate (bbls/d)	24,316	24,645	26,459	28,297	31,569	29,888	30,560	30,404	31,327	30,906	31,162	29,938
NGLs (bbls/d)	8,695	8,074	8,628	9,508	9,588	8,022	8,161	7,772	8,106	7,897	7,814	6,840
Natural gas (mmcf/d)	152.06	144.36	142.13	163.09	172.43	157.88	153.34	151.52	158.93	157.26	152.30	141.59
Total (boe/d)	**58,354**	**56,780**	**58,774**	**64,986**	**69,895**	**64,222**	**64,276**	**63,429**	**65,921**	**65,013**	**64,359**	**60,376**
International												
Crude oil and condensate (bbls/d)	13,859	11,421	15,359	15,689	12,202	17,090	13,864	18,575	16,009	20,163	16,458	16,559
Natural gas (mmcf/d)	83.66	89.62	89.86	93.25	101.99	107.63	107.38	101.83	116.67	120.70	124.48	111.02
Total (boe/d)	**27,802**	**26,357**	**30,336**	**31,229**	**29,201**	**35,028**	**31,760**	**35,547**	**35,454**	**40,279**	**37,204**	**35,062**
Consolidated												
Crude oil and condensate (bbls/d)	38,174	36,066	41,818	43,985	43,771	46,977	44,423	48,979	47,337	51,068	47,620	46,368
NGLs (bbls/d)	8,695	8,074	8,627	9,509	9,588	8,022	8,160	7,772	8,107	7,897	7,815	6,839
Natural gas (mmcf/d)	235.72	233.98	232.00	256.34	274.42	265.51	260.72	253.36	275.60	277.96	276.77	253.38
Total (boe/d)	**86,156**	**83,138**	**89,111**	**96,217**	**99,096**	**99,250**	**96,037**	**98,976**	**101,377**	**105,291**	**101,563**	**95,437**

Financial results

	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18
North America												
Crude oil and condensate sales ($/bbl)	75.43	66.31	51.06	49.79	28.94	50.25	66.31	66.67	72.40	65.95	54.90	80.22
NGL sales ($/bbl)	25.43	29.39	19.20	15.04	8.94	8.92	14.63	6.14	11.25	22.49	25.70	27.97
Natural gas sales ($/mcf)	2.72	3.98	2.77	2.02	1.60	1.92	2.29	1.18	1.15	2.52	1.79	1.46
Sales ($/boe)	42.30	43.08	32.51	28.94	18.24	29.22	38.86	35.52	38.56	40.17	33.94	46.37
Royalties ($/boe)	(5.98)	(5.49)	(3.64)	(3.58)	(1.67)	(3.54)	(4.98)	(4.93)	(4.22)	(5.00)	(5.01)	(6.71)
Transportation ($/boe)	(1.90)	(2.05)	(1.92)	(1.74)	(1.72)	(1.91)	(1.76)	(1.78)	(1.63)	(1.83)	(1.88)	(1.63)
Operating ($/boe)	(10.89)	(11.21)	(10.94)	(7.82)	(9.60)	(11.93)	(11.15)	(10.67)	(10.66)	(11.46)	(10.96)	(10.48)
General and administration ($/boe)	(0.91)	(1.34)	(1.94)	(0.78)	(1.52)	(0.84)	(0.97)	(0.60)	(1.04)	(0.83)	(0.28)	(0.36)
Corporate income taxes ($/boe)	(0.04)	(0.04)	0.04	(0.02)	(0.02)	(0.04)	(0.11)	0.09	(0.02)	(0.03)	0.10	(0.16)
PRRT ($/boe)	—	—	—	—	—	—	—	—	—	—	—	—
Fund flows netback ($/boe)	**22.58**	**22.94**	**14.12**	**14.99**	**3.72**	**10.96**	**19.89**	**17.63**	**20.99**	**21.03**	**15.91**	**27.04**
Fund flows from operations	119,916	117,227	76,375	89,635	23,639	64,048	117,623	102,867	125,893	123,071	94,200	150,202
Capital expenditures	(38,847)	(59,113)	(33,781)	(9,575)	(23,979)	(197,926)	(69,775)	(91,027)	(42,047)	(148,091)	(93,092)	(101,223)
Free cash flow	**81,069**	**58,114**	**42,594**	**80,060**	**(340)**	**(133,878)**	**47,848**	**11,840**	**83,846**	**(25,020)**	**1,108**	**48,979**
International												
Crude oil and condensate sales ($/bbl)	85.41	81.40	62.65	58.19	50.27	73.35	82.14	84.55	93.28	84.95	87.56	95.32
Natural gas sales ($/mcf)	9.83	7.98	6.27	2.91	2.28	4.44	5.49	4.29	5.73	8.46	10.78	10.34
Sales ($/boe)	72.16	62.39	50.30	37.94	28.98	49.42	54.42	56.46	60.98	67.87	74.80	77.76
Royalties ($/boe)	(3.83)	(3.53)	(3.02)	(3.32)	(2.16)	(3.27)	(3.85)	(3.89)	(3.97)	(3.89)	(4.16)	(5.13)
Transportation ($/boe)	(4.64)	(2.76)	(2.40)	(2.28)	(2.04)	(1.94)	(1.77)	(2.76)	(3.40)	(1.66)	(1.70)	(1.45)
Operating ($/boe)	(16.56)	(16.42)	(16.99)	(15.18)	(14.35)	(16.13)	(15.28)	(13.13)	(11.76)	(15.28)	(13.89)	(12.26)
General and administration ($/boe)	(2.61)	(2.06)	(2.92)	(2.53)	(2.72)	(2.63)	(3.70)	(3.10)	(2.93)	(2.27)	(3.27)	(3.49)
Corporate income taxes ($/boe)	(0.19)	0.66	2.25	0.04	(0.02)	(0.11)	2.22	(1.55)	(3.63)	(4.30)	(2.49)	(2.65)
PRRT ($/boe)	(0.58)	(0.60)	(1.45)	(1.27)	(1.21)	(2.90)	(0.50)	(1.78)	(2.56)	(2.87)	0.71	0.08
Fund flows netback ($/boe)	**43.74**	**37.69**	**25.77**	**13.40**	**6.47**	**22.44**	**31.54**	**30.26**	**32.73**	**37.60**	**49.99**	**52.88**
Fund flows from operations	110,654	89,403	71,934	38,498	17,193	71,526	92,160	98,955	105,600	136,298	171,119	170,563
Capital expenditures	(40,329)	(24,250)	(26,113)	(21,755)	(18,295)	(35,778)	(30,850)	(36,852)	(50,560)	(53,962)	(70,488)	(44,962)
Free cash flow	**70,325**	**65,153**	**45,821**	**16,743**	**(1,102)**	**35,748**	**61,310**	**62,103**	**55,040**	**82,336**	**100,631**	**125,601**

	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18
Consolidated												
Crude oil and condensate sales ($/bbl)	79.06	71.09	55.31	52.79	34.89	58.66	71.25	73.45	79.46	73.45	66.19	85.84
NGL sales ($/bbl)	25.43	29.39	19.20	15.04	8.94	8.92	14.63	6.14	11.25	22.49	25.69	27.97
Natural gas sales ($/mcf)	5.24	5.51	4.13	2.34	1.85	2.94	3.61	2.43	3.09	5.10	5.83	5.35
Sales ($/boe)	51.93	49.20	38.57	31.86	21.40	36.35	44.01	43.04	46.40	50.77	48.90	57.90
Royalties ($/boe)	(5.29)	(4.87)	(3.43)	(3.50)	(1.81)	(3.45)	(4.60)	(4.56)	(4.13)	(4.58)	(4.70)	(6.13)
Transportation ($/boe)	(2.78)	(2.27)	(2.08)	(1.92)	(1.81)	(1.92)	(1.76)	(2.13)	(2.25)	(1.76)	(1.81)	(1.56)
Operating ($/boe)	(12.72)	(12.86)	(13.00)	(10.21)	(11.00)	(13.41)	(12.52)	(11.55)	(11.04)	(12.92)	(12.04)	(11.13)
General and administration ($/boe)	(1.46)	(1.57)	(2.27)	(1.35)	(1.88)	(1.47)	(1.88)	(1.50)	(1.70)	(1.38)	(1.37)	(1.51)
Corporate income taxes ($/boe)	(0.09)	0.18	0.80	—	(0.02)	(0.06)	0.66	(0.50)	(1.28)	(1.66)	(0.85)	(1.07)
PRRT ($/boe)	(0.19)	(0.19)	(0.49)	(0.41)	(0.36)	(1.02)	(0.16)	(0.64)	(0.90)	(1.10)	0.26	0.03
Interest ($/boe)	(2.41)	(2.57)	(2.42)	(1.97)	(1.98)	(2.21)	(2.17)	(2.16)	(2.34)	(2.21)	(2.23)	(2.25)
Realized derivatives ($/boe)	(5.05)	(3.43)	0.10	0.47	6.07	5.47	2.57	4.06	1.54	1.09	(3.03)	(4.26)
Realized foreign exchange ($/boe)	(0.25)	(0.69)	0.16	(0.31)	0.44	0.94	0.23	(0.37)	(0.17)	(0.22)	0.63	(0.35)
Realized other ($/boe)	0.35	0.73	0.56	0.29	0.03	(0.37)	0.03	0.04	0.02	0.73	0.03	0.02
Fund flows netback ($/boe)	**22.06**	**21.66**	**16.49**	**12.97**	**9.08**	**18.85**	**24.40**	**23.74**	**24.14**	**26.76**	**23.80**	**29.69**
Fund flows from operations	172,942	162,051	135,212	114,776	81,852	170,225	215,592	216,153	222,738	253,572	222,342	260,705
Capital expenditures	(79,176)	(83,363)	(59,894)	(31,330)	(42,274)	(233,704)	(100,625)	(127,879)	(92,607)	(202,053)	(163,580)	(146,185)
Free cash flow	**93,766**	**78,688**	**75,318**	**83,446**	**39,578**	**(63,479)**	**114,967**	**88,274**	**130,131**	**51,519**	**58,762**	**114,520**

Non-GAAP 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 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 measure of capital in accordance with IAS 1 “Presentation of Financial Statements” (please see Capital Disclosures in the Notes to the Condensed Consolidated Interim Financial Statements).

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

Acquisitions: The sum of acquisitions 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 plus or net of 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.

Capital expenditures: The sum of drilling and development and exploration and evaluation 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.

Cash dividends per share: Represents cash dividends declared per share and is a useful measure of the dividends a common shareholder was entitled to during the period.

Covenants: The financial covenants on our revolving credit facility contain non-GAAP measures. The definitions for these financial covenants are included in Financial Position Review.

Diluted shares outstanding: The sum of shares outstanding at the period end plus outstanding awards under the VIP, based on current estimates of future performance factors and forfeiture rates.

Free cash flow: Represents fund flows from operations in excess of capital expenditures. We use free cash flow to determine the funding available for investing and financing activities, including payment of dividends, repayment of long-term debt, reallocation to existing business units, and deployment into new ventures. We also assess free cash flow as a percentage of fund flows from operations, which is a measure of the percentage of fund flows from operations that is retained for incremental investing and financing activities.

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

Net dividends: We define net dividends as dividends declared less proceeds received for the issuance of shares pursuant to the Dividend Reinvestment Plan. Management monitors net dividends and net dividends as a percentage of fund flows from operations to assess our ability to pay dividends.

Operating netback: Sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses presented on a per unit basis. Management assesses operating netback as a measure of the profitability and efficiency of our field operations. In contrast, fund flows from operations netback also includes general and administration expense, corporate income taxes, and interest. Fund flows from operations netback is used by management to assess the profitability of our business units and Vermilion as a whole.

Payout: We define payout as net dividends plus drilling and development costs, exploration and evaluation costs, and asset retirement obligations settled. Management uses payout and payout as a percentage of fund flows from operations (also referred to as the **payout or sustainability ratio**) to assess the amount of cash distributed back to shareholders and re-invested in the business for maintaining production and organic growth.

Return on capital employed (ROCE): ROCE is a measure that we use to analyze our profitability and the efficiency of our capital allocation process. ROCE is calculated by dividing net earnings 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.

The following tables reconcile net dividends, payout, and diluted shares outstanding from their most directly comparable GAAP measures as presented in our financial statements:

($M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Dividends declared	**—**	—	**—**	90,067
Shares issued for the Dividend Reinvestment Plan	**—**	(632)	**—**	(8,277)
Net dividends	**—**	—	**—**	81,790
Drilling and development	**77,703**	42,383	**157,215**	269,816
Exploration and evaluation	**1,473**	(109)	**5,324**	6,162
Asset retirement obligations settled	**3,321**	970	**10,344**	4,702
Payout	**82,497**	42,612	**172,883**	362,470
% of fund flows from operations	**48 %**	52 %	**52 %**	144 %

('000s of shares)	Q2 2021	Q2 2020
Shares outstanding	**161,893**	158,307
Potential shares issuable pursuant to the VIP	**7,010**	5,783
Diluted shares outstanding	**168,903**	164,090

The following table reconciles the calculation of return on capital employed:

	Twelve Months Ended	
($M)	Jun 30, 2021	Jun 30, 2020
Net earnings (loss)	**823,605**	(1,398,546)
Taxes	**172,462**	(273,324)
Interest expense	**75,305**	76,699
EBIT	**1,071,372**	(1,595,171)
Average capital employed	**4,436,484**	4,826,230
Return on capital employed	**24 %**	(33)%

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 4, 8, 10]
Calgary, Alberta

Carin Knickel [5, 8, 12]
Golden, Colorado

Stephen P. Larke [4, 6, 12]
Calgary, Alberta

Timothy R. Marchant [7, 10, 11]
Calgary, Alberta

Robert Michaleski [3, 6]
Calgary, Alberta

William Roby [8, 9, 12]
Katy, Texas

Manjit Sharma [4,8]
Toronto, Ontario

Judy Steele [6,12]
Halifax, Nova Scotia

Catherine L. Williams [4, 6]
Calgary, Alberta

1 Executive Chairman
2 Lead Director (Independent)
3 Audit Committee Chair (Independent)
4 Audit Committee Member
5 Governance and Human Resources Committee Chair (Independent)
6 Governance and Human Resources Committee Member
7 Health, Safety and Environment Committee Chair (Independent)
8 Health, Safety and Environment Committee Member
9 Independent Reserves Committee Chair (Independent)
10 Independent Reserves Committee Member
11 Sustainability Committee Chair (Independent)
12 Sustainability Committee Member

OFFICERS / CORPORATE SECRETARY

Lorenzo Donadeo *
Executive Chairman

Curtis Hicks *
President

Lars Glemser *
Vice President & Chief Financial Officer

Dion Hatcher *
Vice President North America

Terry Hergott
Vice President Marketing

Yvonne Jeffery
Vice President Sustainability

Darcy Kerwin *
Vice President International & HSE

Kyle Preston
Vice President Investor Relations

Jenson Tan *
Vice President Business Development

Gerard Schut *
Vice President European Operations

Robert (Bob) J. Engbloom
Corporate Secretary

* Executive Committee

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Export Development Canada

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

Wells Fargo Bank N.A., Canadian Branch

Bank of America N.A., Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Alberta Treasury Branches

Canadian Western Bank

Goldman Sachs Lending Partners LLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
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”)

INVESTOR RELATIONS
Kyle Preston
Vice President Investor Relations
403-476-8431 TEL
403-476-8100 FAX
1-866-895-8101 IR TOLL FREE
investor_relations@vermilionenergy.com

EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

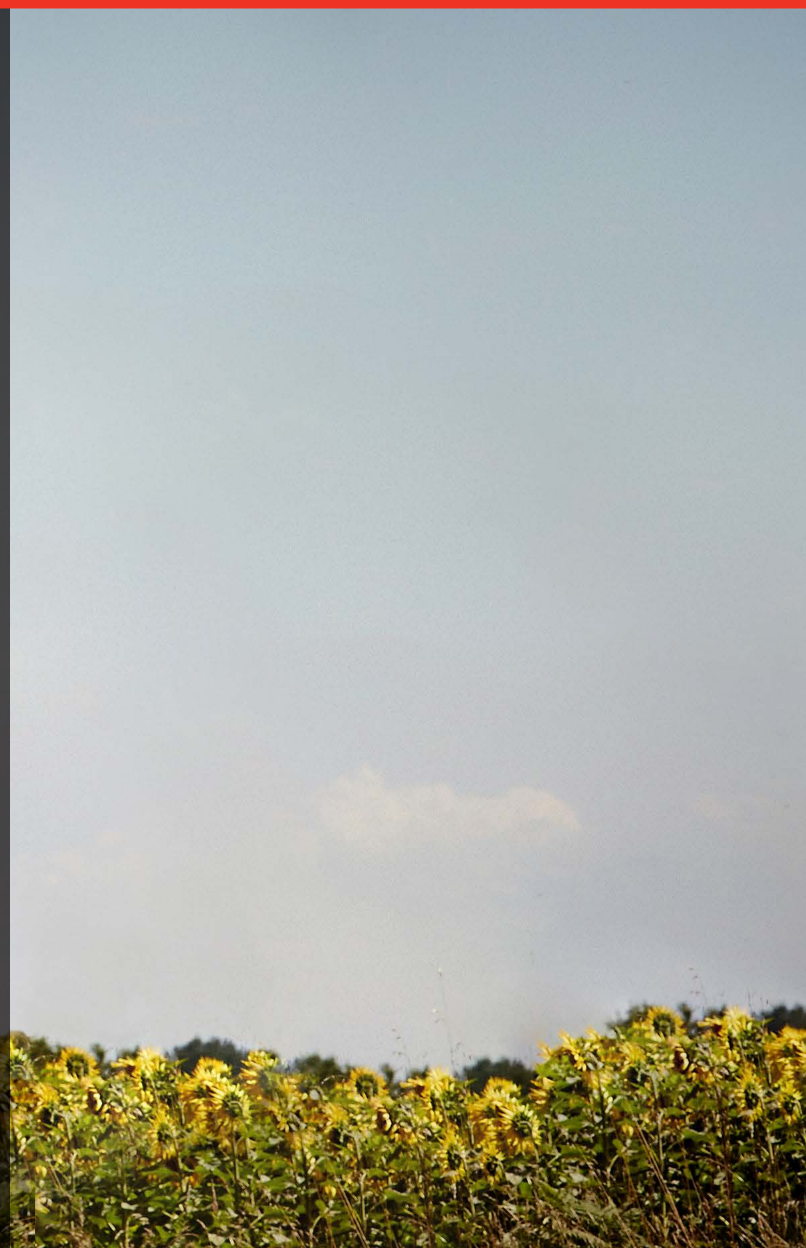
At Vermilion, we operate with honesty and fairness, and can be counted on to do what we say we will.

RESPECT

We embrace diversity, value our people and believe every employee and business associate worldwide deserves to be treated with the utmost dignity and respect.

RESPONSIBILITY

Vermilion continually shows its commitment to the care of our people and environment, and enrichment of the communities in which we live and work.



VERMILION ENERGY

Vermilion Energy Inc.
3500, 520 3rd Avenue SW
Calgary, Alberta T2P 0R3

Telephone: 1.403.269.4884
Facsimile: 1.403.476.8100
IR Toll Free: 1.866.895.8101
investor_relations@vermilionenergy.com

vermilionenergy.com