

Q3 2019

MANAGEMENT'S DISCUSSION AND ANALYSIS

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.



INTERNATIONALLY DIVERSIFIED | SUSTAINABLE GROWTH AND INCOME

VERMILION
E N E R G Y



FRONT COVER THEME

As illustrated by the front cover photo of our operations in Germany, Vermilion's integration of sustainability throughout our business recognizes that we are part of a larger whole: the environments and communities in which we operate. We are therefore committed to conducting our activities in a manner that will protect the health and safety of both. This includes understanding our role in the evolving energy transition within the broader context of the United Nations Sustainable Development Goals ("SDGs"). We believe this approach, in which sustainability is embedded in our corporate strategy, supports Vermilion's long-term economic viability while building a better future for our stakeholders through enhanced economic, environmental and community wellbeing.

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.

Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated October 30, 2019, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three and nine months ended September 30, 2019 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 nine months ended September 30, 2019 and the audited consolidated financial statements for the years ended December 31, 2018 and 2017, 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 nine months ended September 30, 2019 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.
- **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".

Condensate Presentation

We report our condensate production in Canada and the Netherlands business units within the crude oil and condensate production line. We believe that this presentation better reflects the historical and forecasted pricing for condensate, which is more closely correlated with crude oil pricing than with pricing for propane, butane and ethane (collectively “NGLs” for the purposes of this report).

Guidance

On October 25, 2018, we released our 2019 capital budget and related guidance. On February 27, 2019, we deferred some activity to later in the year and reallocated capital between business units, although the 2019 total budget and production guidance remained unchanged. On October 31, 2019, we reduced our 2019 capital expenditure guidance to \$520 million and our 2019 annual production guidance to 100,000 to 101,000 boe/d.

We released our 2020 capital budget and associated production guidance concurrent with the release of our Q3 2019 results.

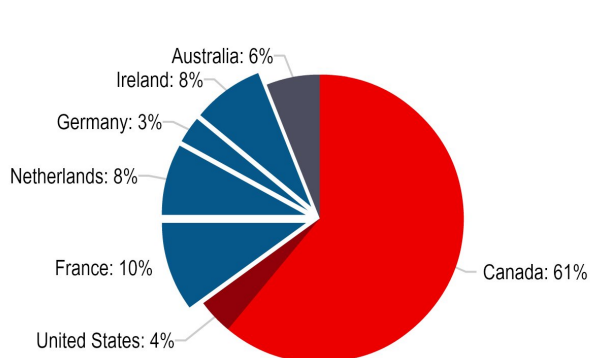
The following table summarizes our guidance:

	Date	Capital Expenditures (\$MM)	Production (boe/d)
2019 Guidance			
2019 Guidance	October 25, 2018	530	101,000 to 106,000
2019 Guidance	October 31, 2019	520	100,000 to 101,000
2020 Guidance			
2020 Guidance	October 31, 2019	450	100,000 to 103,000

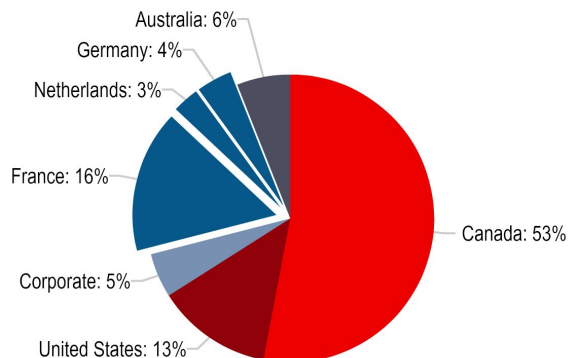
Vermilion's Business

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. This MD&A separately discusses each of our business units in addition to our corporate segment.

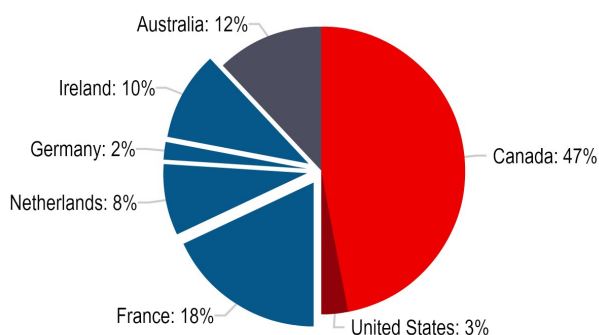
2019 YTD production of 101,193 boe/d by business unit



2019 YTD capital expenditures of \$423MM by business unit



2019 YTD fund flows from operations of \$692MM by business unit

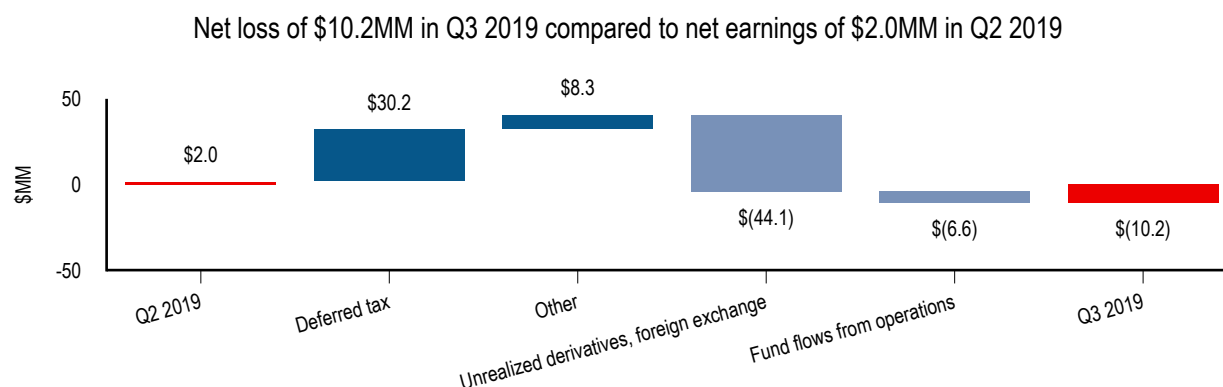


Consolidated Results Overview

	Q3 2019	Q2 2019	Q3 2018	Q3/19 vs. Q2/19	Q3/19 vs. Q3/18	YTD 2019	YTD 2018	2019 vs. 2018
Production								
Crude oil and condensate (bbls/d)	47,242	48,964	47,152	(3.5)%	0.2%	48,455	36,318	33.4%
NGLs (bbls/d)	7,772	8,107	6,839	(4.1)%	13.6%	7,925	5,878	34.8%
Natural gas (mmcf/d)	253.36	275.60	253.38	(8.1)%	—%	268.88	241.42	11.4%
Total (boe/d)	97,239	103,003	96,222	(5.6)%	1.1%	101,193	82,433	22.8%
Sales								
Crude oil and condensate (bbls/d)	48,979	47,337	46,368	3.5%	5.6%	49,120	35,749	37.4%
NGLs (bbls/d)	7,772	8,107	6,839	(4.1)%	13.6%	7,925	5,878	34.8%
Natural gas (mmcf/d)	253.36	275.60	253.38	(8.1)%	—%	268.88	241.42	11.4%
Total (boe/d)	98,976	101,377	95,437	(2.4)%	3.7%	101,858	81,864	24.4%
(Draw) build in inventory (mbbls)	(159)	149	73			(182)	155	
Financial metrics								
Fund flows from operations (\$M)	216,153	222,738	260,705	(3.0)%	(17.1)%	692,463	616,310	12.4%
Per share (\$/basic share)	1.39	1.44	1.71	(3.5)%	(18.7)%	4.49	4.51	(0.4)%
Net (loss) earnings (\$M)	(10,229)	2,004	(15,099)	N/A	(32.3)%	31,322	(51,723)	N/A
Per share (\$/basic share)	(0.07)	0.01	(0.10)	N/A	(30.0)%	0.20	(0.38)	N/A
Net debt (\$M)	2,001,870	1,950,509	2,034,086	2.6%	(1.6)%	2,001,870	2,034,086	(1.6)%
Cash dividends (\$/share)	0.690	0.690	0.690	—%	—%	2.070	2.025	2.2%
Activity								
Capital expenditures (\$M)	127,879	92,607	146,185	38.1%	(12.5)%	422,539	354,634	19.1%
Acquisitions (\$M)	4,657	8,623	198,173			29,307	1,756,736	
Gross wells drilled	47.00	35.00	65.00			148.00	112.00	
Net wells drilled	45.31	27.88	58.97			136.13	102.85	

Financial performance review

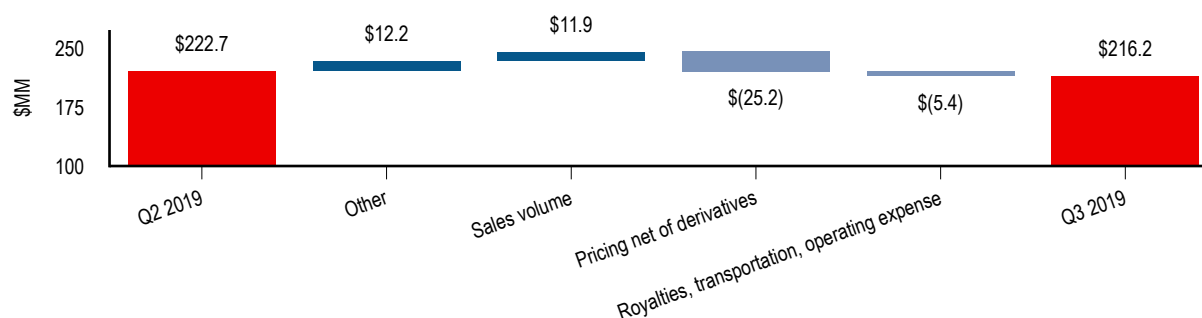
Q3 2019 vs. Q2 2019



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

- We recorded a net loss for Q3 2019 of \$10.2 million (\$0.07/basic share) compared to net earnings of \$2.0 million (\$0.01/basic share) in Q2 2019. This quarter-over-quarter decrease in net earnings was primarily attributable to an unrealized loss on foreign exchange of \$50.7 million (compared to an unrealized gain of \$41.8 million for Q2 2019). This decrease was partially offset by a decrease in deferred tax expense of \$30.2 million.

3% decrease in fund flows from operations from Q2 2019 to Q3 2019

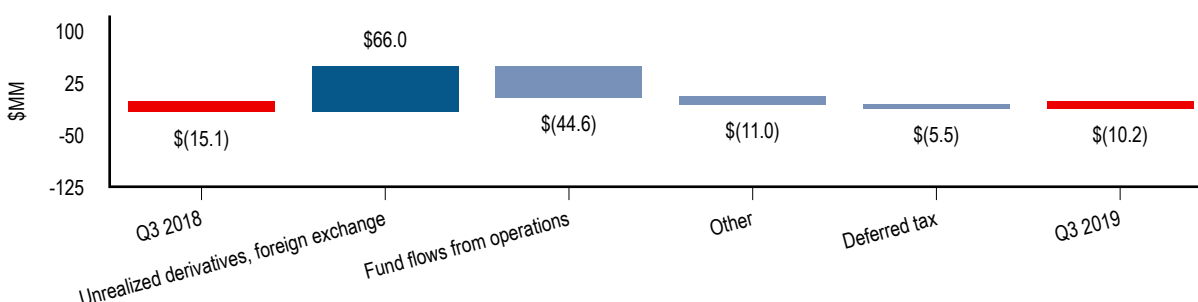


"Other" contains general and administration, corporate income taxes, interest, realized foreign exchange, and realized other

- We generated fund flows from operations of \$216.2 million during Q3 2019, a slight decrease of 3% from Q2 2019 despite more significant decreases in commodity prices quarter-over-quarter, which included an 11% decrease in Dated Brent and a 23% decrease in TTF prices.
- We were able to mitigate a portion of the impact of commodity prices with our hedge program, which is designed to reduce volatility in our cash flows. Decreases in commodity prices reduced our realized price per barrel by \$3.36 per boe, which was partially offset by a \$2.52 per boe increase in realized derivative gains.
- In addition, we were able to reduce a portion of the impact of commodity prices by reducing our corporate costs, included in "Other" in the above chart. We realized a 9% reduction in interest expense as a result of our cross currency interest rate swaps entered into in Q2 2019 and an 11% reduction in general and administration expense.

Q3 2019 vs. Q3 2018

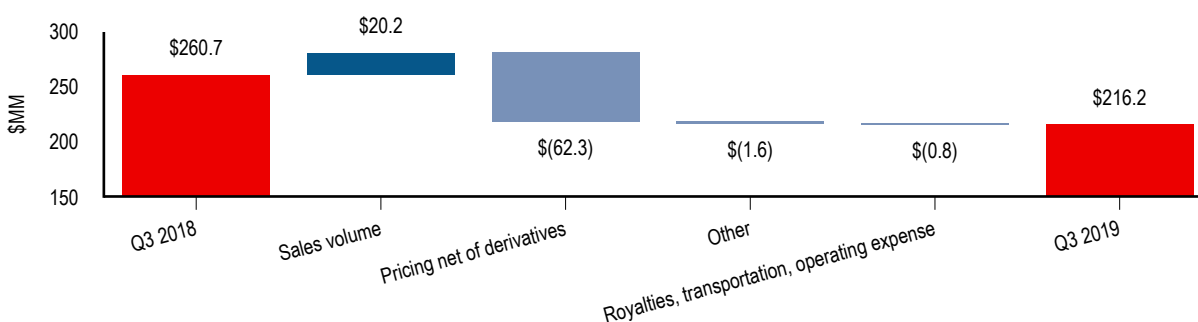
Net loss of \$10.2MM in Q3 2019 compared to a net loss of \$15.1MM in Q3 2018



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

- We recorded a net loss for Q3 2019 of \$10.2 million (\$0.07/basic share) compared to a net loss of \$15.1 million (\$0.10/basic share) in Q3 2018. This change is primarily driven by an unrealized gain on derivative instruments of \$17.8 million in Q3 2019 (compared to an unrealized loss of \$75.8 million in Q3 2018) offset by an unrealized foreign exchange loss of \$50.7 million in Q3 2019 (compared to an unrealized loss of \$23.0 million in Q3 2018). This was partially offset by a decrease in funds flow from operations of \$44.6 million.

17% decrease in fund flows from operations from Q3 2018 to Q3 2019

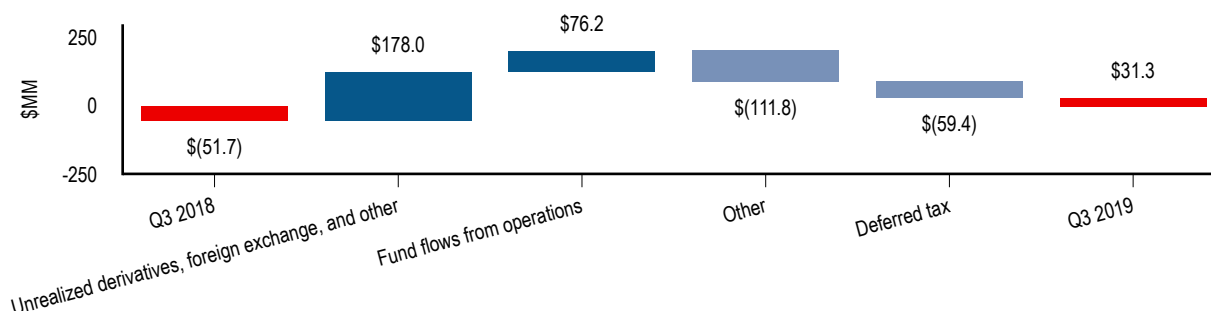


"Other" contains general and administration, corporate income taxes, interest, realized FX, and realized other

- We generated fund flows from operations of \$216.2 million in Q3 2019, a decrease from \$260.7 million in Q3 2018. We increased our sales volumes year-over-year by 4% following the successful drilling campaigns in Australia and the United States. The resulting increase in revenues were offset by lower commodity prices.

YTD 2019 vs. YTD 2018

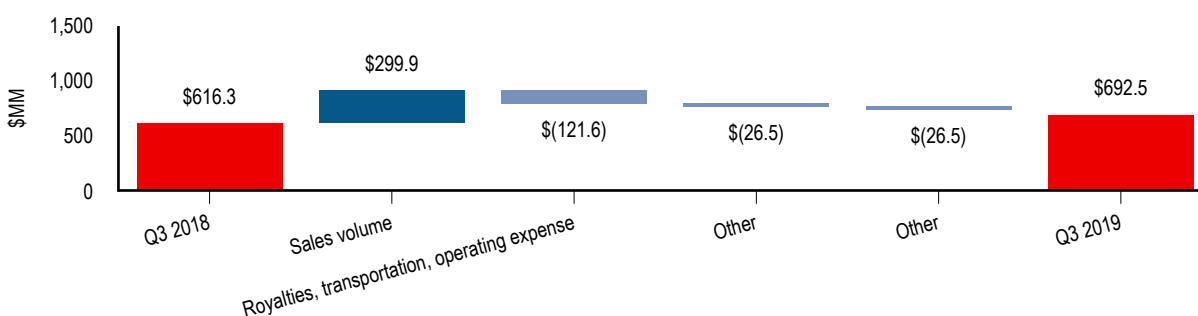
Net earning \$31.3MM in YTD 2019 compared to net loss of \$51.7MM in YTD 2018



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

- For the nine months ended September 30, 2019, net earnings of \$31.3 million were recorded compared to a net loss of \$51.7 million for the comparable period in 2018. The increase in net earnings resulted from a year-over-year increase in fund flows from operations of \$76.2 million due to increased sales volumes offset by related incremental expenses associated with the increased volumes and lower commodity prices. The increase in net earnings is also due to lower unrealized losses year over year. For the nine months ended September 30, 2019, we recognized an unrealized gain on foreign exchange of \$14.4 million and an unrealized loss on derivative instruments of \$27.1 million (compared to unrealized losses of \$26.9 million and \$163.8 million respectively, for the comparable period in 2018). These increases to net earnings were partially offset by an increase of \$100.6 million in depletion and depreciation expense associated with higher sales volumes.

12% increase in fund flows from operations from YTD 2018 to YTD 2019



"Other" contains general and administration, current income taxes, interest, realized foreign exchange, and realized other

- Fund flows from operations increased 12% for the nine months ended September 30, 2019 versus the same period in 2018 due to a 24% increase in sales volumes. Our consolidated realized price decreased by 14% from \$54.64/boe to \$46.79/boe due to weaker crude oil and natural gas pricing.
- We were able to mitigate a portion of the impact of commodity prices with our hedge program, which is designed to reduce volatility in our cash flows. Decreases in commodity prices reduced our realized price per barrel by \$7.85 per boe, which was partially offset by a \$5.92 per boe increase in realized derivative gains.

Production review

Q3 2019 vs. Q2 2019

- Consolidated average production of 97,239 boe/d during Q3 2019 decreased 6% compared to Q2 2019 production of 103,003 boe/d. Production increased in the United States from organic growth and in France as production volumes in the Paris Basin returned to near full capacity in mid-August following the impact of a third party refinery outage in Q2 2019. These increases were offset by lower production as a result of a number of operated and non-operated plant turnarounds during the quarter, unplanned downtime in Netherlands and Ireland, and weather delays.

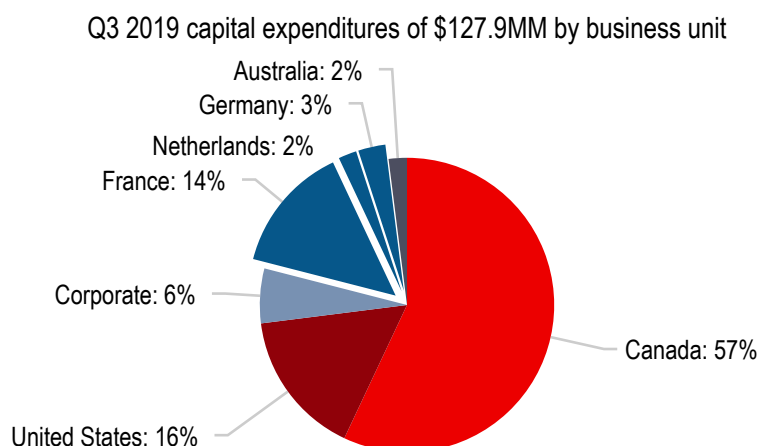
Q3 2019 vs. Q3 2018

- Consolidated average production of 97,239 boe/d in Q3 2019 represented an increase of 1% from Q3 2018 due to growth in the United States, Canada, and Australia. In the United States, production growth resulted from an acquisition in Q3 2018 and organic drilling activity, including bringing on production four (4.0 net) wells in Q3 2019. In Canada, production growth resulted from the continued development of our southeast Saskatchewan light oil development and our Mannville condensate-rich resource play. Production in Australia increased due to the two-well drilling program brought on production in Q1 2019. These increases were partially offset by lower production in Ireland and France.

YTD 2019 vs. YTD 2018

- For the nine months ended September 30, 2019, consolidated average production of 101,193 boe/d represented an increase of 23% from the comparable period in 2018 due to growth in Canada, the United States, Australia, and the Netherlands. In Canada, production increased as a result of acquisitions in 2018 and continued organic growth. In the United States, production increases resulted from an acquisition in Q3 2018 and eight (8.0 net) wells drilled and brought on production in year-to-date 2019. Production in Australia increased due to the two-well drilling program brought on production in Q1 2019. In the Netherlands, production increased as a result of a new well brought on production in Q3 2018 and from a successful workover program in the first half of 2019.

Activity review



- For the three months ended September 30, 2019, capital expenditures of \$127.9 million primarily related to activity in Canada, the United States, and France. In Canada, capital expenditures of \$70.0 million included the drilling of 40.0 (38.3 net) wells, all of which were drilled in Saskatchewan. Capital expenditures of \$21.1 million in the United States related to drilling, completing and bringing on production four (4.0 net) wells. In France, capital expenditures of \$18.1 million related to workovers and facility costs.

Sustainability review

Dividends

- Declared dividends of \$0.23 per common share per month throughout 2019, resulting in total dividends declared of \$2.07 per common share for the nine months ended September 30, 2019.

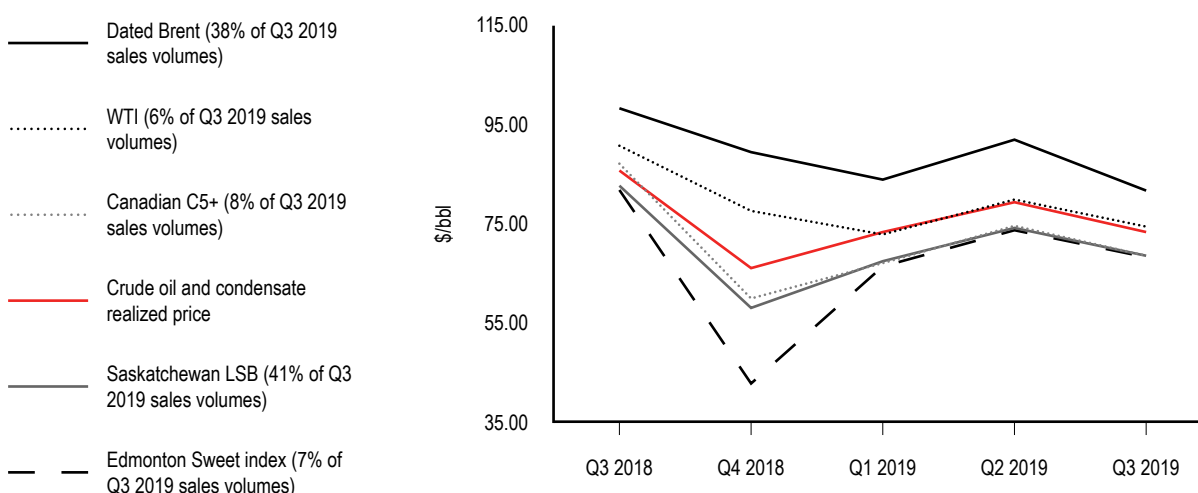
Long-term debt and net debt

- Long-term debt increased to \$2.0 billion as at September 30, 2019 from \$1.8 billion as at December 31, 2018. This increase was primarily a result of increased borrowings on the revolving credit facility and was partially offset by the impact of the stronger Canadian dollar on our US-denominated Senior Unsecured Notes.
- Net debt increased to \$2.0 billion as at September 30, 2019, from \$1.9 billion at December 31, 2018, primarily due to increased borrowings on our revolving credit facility.
- The ratio of net debt to trailing twelve months fund flows from operations decreased to 2.19 (December 31, 2018 - 2.30) as the increase to net debt was offset by higher trailing twelve months fund flows from operations.

Benchmark Commodity Prices

	Q3 2019	Q2 2019	Q3 2018	Q3/19 vs. Q2/19	Q3/19 vs. Q3/18	YTD 2019	YTD 2018	2019 vs. 2018
Crude oil								
WTI (\$/bbl)	74.55	80.00	90.83	(6.8)%	(17.9)%	75.84	85.95	(11.8)%
WTI (US \$/bbl)	56.45	59.81	69.50	(5.6)%	(18.8)%	57.06	66.75	(14.5)%
Edmonton Sweet index (\$/bbl)	68.39	73.82	81.92	(7.4)%	(16.5)%	69.57	78.14	(11.0)%
Edmonton Sweet index (US \$/bbl)	51.79	55.19	62.68	(6.2)%	(17.4)%	52.34	60.69	(13.8)%
Saskatchewan LSB index (\$/bbl)	68.68	74.28	82.79	(7.5)%	(17.0)%	70.19	78.04	(10.1)%
Saskatchewan LSB index (US \$/bbl)	52.01	55.54	63.35	(6.4)%	(17.9)%	52.81	60.61	(12.9)%
Canadian C5+ Condensate index (\$/bbl)	68.70	74.70	87.22	(8.0)%	(21.2)%	70.19	85.24	(17.7)%
Canadian C5+ Condensate index (US \$/bbl)	52.02	55.85	66.74	(6.9)%	(22.1)%	52.81	66.20	(20.2)%
Dated Brent (\$/bbl)	81.80	92.05	98.37	(11.1)%	(16.8)%	85.93	92.87	(7.5)%
Dated Brent (US \$/bbl)	61.94	68.82	75.27	(10.0)%	(17.7)%	64.65	72.13	(10.4)%
Natural gas								
AECO (\$/mcf)	1.06	1.03	1.19	2.9%	(10.9)%	1.64	1.48	10.8%
NBP (\$/mcf)	4.50	5.44	10.95	(17.3)%	(58.9)%	6.08	10.12	(39.9)%
NBP (€/mcf)	3.07	3.62	7.20	(15.2)%	(57.4)%	4.07	6.58	(38.1)%
TTF (\$/mcf)	4.40	5.75	10.92	(23.5)%	(59.7)%	6.08	10.00	(39.2)%
TTF (€/mcf)	3.00	3.82	7.18	(21.5)%	(58.2)%	4.07	6.50	(37.4)%
Henry Hub (\$/mcf)	2.94	3.53	3.80	(16.7)%	(22.6)%	3.55	3.74	(5.1)%
Henry Hub (US \$/mcf)	2.23	2.64	2.90	(15.5)%	(23.1)%	2.67	2.90	(7.9)%
Average exchange rates								
CDN \$/US \$	1.32	1.34	1.31	(1.5)%	0.8%	1.33	1.29	3.1%
CDN \$/Euro	1.47	1.50	1.52	(2.0)%	(3.3)%	1.49	1.54	(3.2)%
Realized Prices								
Crude oil and condensate (\$/bbl)	73.45	79.46	85.84	(7.6)%	(14.4)%	75.38	84.98	(11.3)%
NGLs (\$/bbl)	6.14	11.25	27.97	(45.4)%	(78.0)%	13.25	26.61	(50.2)%
Natural gas (\$/mcf)	2.43	3.09	5.35	(21.4)%	(54.6)%	3.56	5.30	(32.8)%
Total (\$/boe)	43.04	46.40	57.90	(7.2)%	(25.7)%	46.79	54.64	(14.4)%

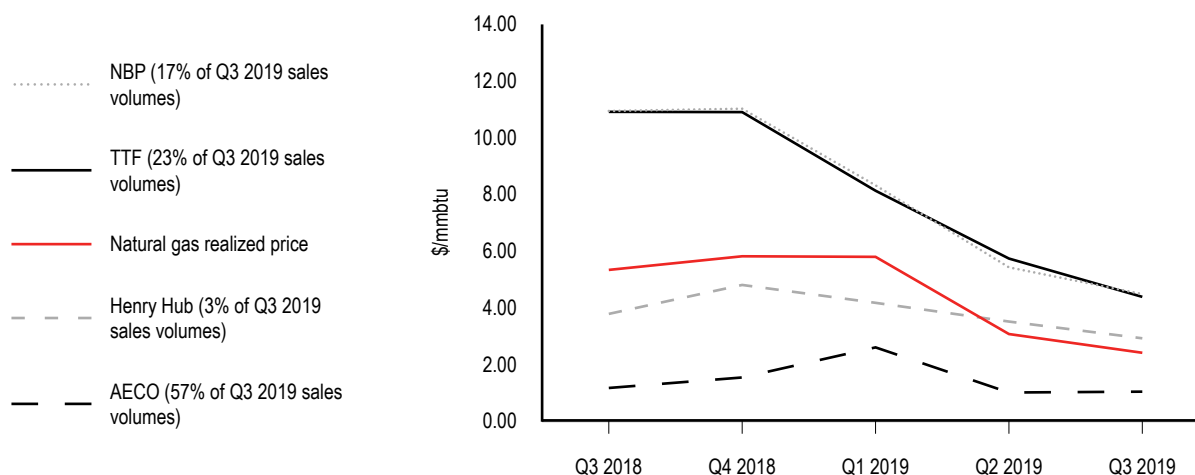
Q3 2019 realized crude oil and condensate price was a 7% premium to Edmonton Sweet Index



- Crude oil prices fell in Q3 2019 relative to Q2 2019, driven by softening sentiment on global oil demand growth. By the end of Q3 2019, quarter-over-quarter WTI and Brent prices decreased by 7% and 11% respectively, in Canadian dollar terms. For the three months ended September 30, 2019, WTI and Brent prices in Canadian dollar terms decreased by 18% and 17%, respectively, versus the comparable period in the prior year.

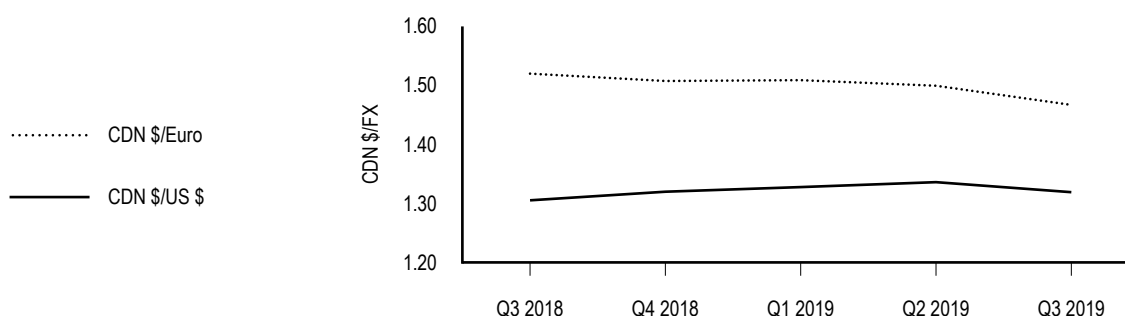
- In Canadian dollar terms, quarter-over-quarter, the Edmonton Sweet differential narrowed by \$0.02/bbl to a discount of \$6.16/bbl against WTI, and the Saskatchewan LSB differential widened by \$0.15/bbl to a discount of \$5.87/bbl against WTI.
- Vermilion's crude oil production benefits from light oil pricing and no exposure to significantly discounted heavy crude oil. Approximately 38% of our Q3 2019 crude oil and condensate production was priced at the Dated Brent index (which averaged a premium to WTI of US\$5.49/bbl), while the remainder of our crude oil and condensate production was priced at the Saskatchewan LSB, Canadian C5+, Edmonton Sweet, and WTI indices. Saskatchewan LSB and Canadian C5+ typically have lower differentials than the more significantly constrained WCS and MSW markers, making Vermilion's North American crude oil production price-advantaged relative to other North American benchmark prices.

Q3 2019 realized natural gas price was a \$1.37/mcf premium to AECO



- In Canadian dollar terms, market prices for European natural gas (TTF and NBP) declined by 17% and 24% respectively in Q3 2019 compared to Q2 2019 primarily due to persistent oversupply during the summer, when demand is seasonally low.
- Natural gas prices at AECO in Q3 2019 increased by 3% compared to Q2 2019.
- For Q3 2019, average European natural gas prices represented a \$3.39/mcf premium to AECO and a \$1.51/mcf premium to Henry Hub pricing. Approximately 40% of our natural gas production in Q3 2019 benefited from this premium European pricing. As a result, our consolidated natural gas realized price was a \$1.37/mcf premium to AECO.

Quarter-over-quarter, the Canadian dollar strengthened slightly versus the Euro and USD



- For the three months ended September 30, 2019, the Canadian dollar strengthened slightly against the US dollar quarter-over-quarter.
- For the three months ended September 30, 2019, the Canadian dollar strengthened slightly against the Euro quarter-over-quarter.

Canada Business Unit

Overview

Production and assets focused in West Pembina near Drayton Valley, Alberta and in southeast Saskatchewan and Manitoba.

- Potential for three significant resource plays sharing the same surface infrastructure in the West Pembina region in Alberta:
 - Mannville condensate-rich gas (2,400 - 2,700m depth) - in development phase
 - Cardium light oil (1,800m depth) - modest investment at present
 - Duvernay condensate-rich gas (3,200 - 3,400m depth) - no investment at present
- Southeast Saskatchewan light oil development:
 - Targeting the Mississippian Midale (1,400 - 1,700m depth), Frobisher/Alida (1,200 - 1,400m depth) and Ratcliffe (1,800 - 1,900m) formations

Operational and financial review

Canada business unit (\$M except as indicated)	Q3 2019	Q2 2019	Q3 2018	Q3/19 vs. Q2/19	Q3/19 vs. Q3/18	YTD 2019	YTD 2018	2019 vs. 2018
Production and sales								
Crude oil and condensate (bbls/d)	27,682	28,844	28,477	(4.0)%	(2.8)%	28,558	18,323	55.9%
NGLs (bbls/d)	6,632	7,352	6,126	(9.8)%	8.3%	6,983	5,611	24.5%
Natural gas (mmcf/d)	145.14	151.87	136.77	(4.4)%	6.1%	149.44	123.54	21.0%
Total (boe/d)	58,504	61,507	57,397	(4.9)%	1.9%	60,447	44,524	35.8%
Production mix (% of total)								
Crude oil and condensate	47%	47%	50%			47%	41%	
NGLs	12%	12%	10%			12%	13%	
Natural gas	41%	41%	40%			41%	46%	
Activity								
Capital expenditures	69,963	29,083	89,837	140.6%	(22.1)%	227,101	187,646	21.0%
Acquisitions	1,746	2,655	6,146			19,061	1,561,731	
Gross wells drilled	40.00	28.00	65.00			126.00	101.00	
Net wells drilled	38.31	22.87	58.97			116.12	91.85	
Financial results								
Sales	188,073	212,944	243,016	(11.7)%	(22.6)%	621,173	484,864	28.1%
Royalties	(23,909)	(20,711)	(33,801)	15.4%	(29.3)%	(69,951)	(59,112)	18.3%
Transportation	(10,404)	(9,781)	(9,057)	6.4%	14.9%	(30,877)	(18,783)	64.4%
Operating	(57,851)	(60,404)	(55,577)	(4.2)%	4.1%	(181,859)	(115,435)	57.5%
General and administration	(5,793)	(7,405)	(1,316)	(21.8)%	340.2%	(15,917)	(3,907)	307.4%
Fund flows from operations	90,116	114,643	143,265	(21.4)%	(37.1)%	322,569	287,627	12.1%
Netbacks (\$/boe)								
Sales	34.94	38.04	46.02	(8.1)%	(24.1)%	37.64	39.89	(5.6)%
Royalties	(4.44)	(3.70)	(6.40)	20.0%	(30.6)%	(4.24)	(4.86)	(12.8)%
Transportation	(1.93)	(1.75)	(1.72)	10.3%	12.2%	(1.87)	(1.55)	20.6%
Operating	(10.75)	(10.79)	(10.52)	(0.4)%	2.2%	(11.02)	(9.50)	16.0%
General and administration	(1.08)	(1.32)	(0.25)	(18.2)%	332.0%	(0.96)	(0.32)	200.0%
Fund flows from operations netback	16.74	20.48	27.13	(18.3)%	(38.3)%	19.55	23.66	(17.4)%
Realized prices								
Crude oil and condensate (\$/bbl)	66.45	72.52	79.86	(8.4)%	(16.8)%	68.16	78.92	(13.6)%
NGLs (\$/bbl)	5.57	10.61	27.82	(47.5)%	(80.0)%	12.79	26.47	(51.7)%
Natural gas (\$/mcf)	1.16	1.12	1.44	3.6%	(19.4)%	1.58	1.47	7.5%
Total (\$/boe)	34.94	38.04	46.02	(8.1)%	(24.1)%	37.64	39.89	(5.6)%
Reference prices								
WTI (US \$/bbl)	56.45	59.81	69.50	(5.6)%	(18.8)%	57.06	66.75	(14.5)%
Edmonton Sweet index (\$/bbl)	68.39	73.82	81.92	(7.4)%	(16.5)%	69.57	78.14	(11.0)%
Saskatchewan LSB index (\$/bbl)	68.68	74.28	82.79	(7.5)%	(17.0)%	70.19	78.04	(10.1)%
Canadian C5+ Condensate index (\$/bbl)	68.70	74.70	87.22	(8.0)%	(21.2)%	70.19	85.24	(17.7)%
AECO (\$/mcf)	1.06	1.03	1.19	2.9%	(10.9)%	1.64	1.48	10.8%

Production

- Q3 2019 production decreased 5% from the prior quarter due to planned turnarounds and project delays caused by abnormally wet weather. Quarterly production increased 2% year-over-year primarily due to our 2019 drilling activity.

Activity review

Vermilion drilled 40 (38.3 net) operated wells in Canada during Q3 2019.

Alberta

- In Q3 2019, we completed two (2.0 net) operated wells, and brought on production two (2.0 net) operated wells and one (0.5 net) non-operated well in Alberta.
- In 2019, we have drilled or participated in 14 (13.5 net) wells in Alberta.

Saskatchewan

- In Q3 2019, we drilled 40 (38.3 net) operated wells, completed 39 (37.6 net) operated wells and three (0.5 net) non-operated wells, and brought 38 (35.7 net) operated wells and three (0.5 net) non-operated wells on production in Saskatchewan.
- In 2019, we have drilled or participated in 112 (102.6 net) wells in Saskatchewan.

Sales

- The realized price for our crude oil and condensate production in Canada is linked to WTI subject to market conditions in western Canada as reflected by the Saskatchewan LSB, Canadian Condensate C5+, and Edmonton Sweet index prices. The realized price of our natural gas in Canada is based on the AECO index.
- Q3 2019 sales per boe decreased 8% compared to Q2 2019 due to lower crude oil, condensate and NGL prices which was partially offset by higher natural gas prices.
- Q3 2019 sales per boe decreased 24% versus Q3 2018 due to a decrease in all reference prices.
- Year-to-date 2019 sales per boe decreased 6% versus the same period in 2018 due to a decrease in crude oil, condensate and NGL prices. This was partially offset by an increase in production weighting to crude oil and condensate and higher natural gas prices.

Royalties

- Q3 2019 royalties as a percentage of sales of 12.7% increased from 9.7% in Q2 2019 primarily due to a favourable adjustment associated with gas cost allowance received in the prior quarter.
- For the three and nine months ended Q3 2019, royalties as a percentage of sales of 12.7% and 11.3%, respectively, decreased from 13.9% and 12.2% in the comparable prior year periods. This decrease was due to the effect of lower crude oil prices on sliding scale royalties coupled with lower average royalty rates for new wells brought on production.

Transportation

- Q3 2019 transportation expense on a dollar and per unit basis increased slightly from Q2 2019 and Q3 2018 due to the impact of a prior period adjustment recorded in the current quarter.
- Transportation expense for the nine months ended September 30, 2019 increased on a per unit basis versus the comparable period in 2018 due to an increased weighting towards crude oil production, which incurs a higher transportation expense.

Operating

- Operating expense on both a basis remained relatively consistent in Q3 2019 as compared to Q2 2019 and Q3 2018.
- For the nine months ended September 30, 2019, operating expense increased on a per unit basis versus the comparable period in 2018. On a dollar basis, the increase in operating expense was driven by higher production volumes during 2019. On a per unit basis, the increase in operating expense was primarily attributable to the impact of increased crude oil production, which has higher associated per unit operating expense.

France Business Unit

Overview

- Entered France in 1997.
- Largest oil producer in France, constituting approximately three-quarters of domestic oil production.
- Low base decline producing assets comprised of large conventional oil fields with high working interests located in the Aquitaine and Paris Basins.
- Identified inventory of workover, waterflood, and infill drilling opportunities.

Operational and financial review

France business unit (\$M except as indicated)	Q3 2019	Q2 2019	Q3 2018	Q3/19 vs. Q2/19	Q3/19 vs. Q3/18	YTD 2019	YTD 2018	2019 vs. 2018
Production								
Crude oil (bbls/d)	10,347	9,800	11,407	5.6%	(9.3)%	10,493	11,377	(7.8)%
Natural gas (mmcf/d)	—	—	—	—%	—%	0.25	—	—%
Total (boe/d)	10,347	9,800	11,407	5.6%	(9.3)%	10,535	11,377	(7.4)%
Sales								
Crude oil (bbls/d)	11,112	10,190	11,482	9.0%	(3.2)%	10,852	11,025	(1.6)%
Natural gas (mmcf/d)	—	—	—	—%	—%	0.25	—	—%
Total (boe/d)	11,112	10,190	11,482	9.0%	(3.2)%	10,894	11,025	(1.2)%
Inventory (mmbbls)								
Opening crude oil inventory	297	332	300			325	197	
Crude oil production	952	892	1,049			2,865	3,106	
Crude oil sales	(1,022)	(927)	(1,056)			(2,963)	(3,010)	
Closing crude oil inventory	227	297	293			227	293	
Activity								
Capital expenditures	18,139	25,671	15,779	(29.3)%	15.0%	65,896	62,750	5.0%
Gross wells drilled	—	1.00	—			4.00	5.00	
Net wells drilled	—	1.00	—			4.00	5.00	
Financial results								
Sales	81,676	84,540	100,840	(3.4)%	(19.0)%	248,918	274,713	(9.4)%
Royalties	(11,476)	(10,871)	(12,765)	5.6%	(10.1)%	(33,630)	(34,805)	(3.4)%
Transportation	(6,183)	(9,041)	(2,013)	(31.6)%	207.2%	(18,394)	(7,184)	156.0%
Operating	(15,098)	(14,305)	(13,733)	5.5%	9.9%	(45,139)	(40,675)	11.0%
General and administration	(3,379)	(3,551)	(3,365)	(4.8)%	0.4%	(10,585)	(10,378)	2.0%
Current income taxes	(3,419)	(5,346)	(6,913)	(36.0)%	(50.5)%	(16,465)	(14,200)	16.0%
Fund flows from operations	42,121	41,426	62,051	1.7%	(32.1)%	124,705	167,471	(25.5)%
Netbacks (\$/boe)								
Sales	79.89	91.17	95.46	(12.4)%	(16.3)%	83.69	91.27	(8.3)%
Royalties	(11.23)	(11.72)	(12.08)	(4.2)%	(7.0)%	(11.31)	(11.56)	(2.2)%
Transportation	(6.05)	(9.75)	(1.91)	(37.9)%	216.8%	(6.18)	(2.39)	158.6%
Operating	(14.77)	(15.43)	(13.00)	(4.3)%	13.6%	(15.18)	(13.51)	12.4%
General and administration	(3.31)	(3.83)	(3.19)	(13.6)%	3.8%	(3.56)	(3.45)	3.2%
Current income taxes	(3.34)	(5.77)	(6.54)	(42.1)%	(48.9)%	(5.54)	(4.72)	17.4%
Fund flows from operations netback	41.19	44.67	58.74	(7.8)%	(29.9)%	41.92	55.64	(24.7)%
Reference prices								
Dated Brent (US \$/bbl)	61.94	68.82	75.27	(10.0)%	(17.7)%	64.65	72.13	(10.4)%
Dated Brent (\$/bbl)	81.80	92.05	98.37	(11.1)%	(16.8)%	85.93	92.87	(7.5)%

Production

- Q3 2019 production increased 6% from the prior quarter. Production volumes in the Paris Basin returned to near full capacity in mid-August following the restart of the Grandpuits refinery which had been offline due to a failure on its main feedstock pipeline. In the Aquitaine Basin, production was relatively consistent with the prior quarter as we successfully completed our 2019 workover campaign, which continues to yield results above our expectations. Quarterly production decreased 9% year-over-year as a result of the third party refinery outage.

Activity review

- During Q3 2019, we continued to execute workovers in the Aquitaine Basin, while workover activities in the Paris Basin were deferred as a result of the third party refinery outage.
- We plan to continue our workover and optimization programs in the Aquitaine and Paris Basins throughout 2019.

Sales

- Crude oil in France is priced with reference to Dated Brent.
- For the three and nine months ended September 30, 2019, sales per boe decreased versus all comparable periods, consistent with decreases in the Dated Brent reference price.

Royalties

- Royalties in France relate to two components: RCDM (levied on units of production and not subject to changes in commodity prices) and R31 (based on a percentage of sales).
- For the three and nine months ended September 30, 2019, royalties as a percentage of sales of 14.1% and 13.5%, respectively, were higher than the comparable periods due to the impact of RCDM royalties and lower sales prices.

Transportation

- Transportation expense decreased in Q3 2019 compared to Q2 2019 due to the aforementioned refinery outage, which had a greater impact on Q2 2019 than Q3 2019. During the refinery outage, we used alternate delivery points and transportation methods for our crude oil production in the basin, resulting in an increase to our transportation costs during the shutdown.
- Transportation expense for the three and nine months ended September 30, 2019 increased versus the comparable periods in the prior year due to the aforementioned refinery outage.

Operating

- Q3 2019 operating expense increased due to an electricity credit received in Q2 2019 and the impact of expenditure timing. Operating expense on a per unit basis was lower compared to Q2 2019 despite the increase on a dollar basis as a result of higher production volumes.
- For the three and nine months ended September 30, 2019 compared to the same periods in the prior year, operating expense increased on both a dollar and per unit basis due primarily to higher electricity prices in the current year.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- In France, current income taxes are applied to taxable income, after eligible deductions, at a statutory rate of 32.0%.
- Full year effective tax rates are estimated each quarter based on forecasted commodity prices and operational results. The estimated full year effective tax rate is applied on a pro-rata basis to quarterly results. As such, fluctuations between the reporting periods occur due to changes in estimated tax rates.
- For 2019, the effective rate on current taxes, inclusive of corporate allocations, is expected to be between 9% to 11% of pre-tax fund flows from operations. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- On December 21, 2017, the French Parliament approved the Finance Bill for 2018. The Finance Bill for 2018 provides for a progressive decrease of the French corporate income tax rate from 34.4% to 25.8% by 2022, with the first reduction in 2019 to 32.0%.

Netherlands Business Unit

Overview

- Entered the Netherlands in 2004.
- Second largest onshore operator.
- Interests include 26 onshore licenses (all operated) and 17 offshore licenses (all non-operated).
- Licenses include more than 930,000 net acres of land, 90% of which is undeveloped.

Operational and financial review

Netherlands business unit (\$M except as indicated)	Q3 2019	Q2 2019	Q3 2018	Q3/19 vs. Q2/19	Q3/19 vs. Q3/18	YTD 2019	YTD 2018	2019 vs. 2018
Production and sales								
Condensate (bbls/d)	82	100	84	(18.0)%	(2.4)%	92	83	10.8%
Natural gas (mmcf/d)	44.08	52.90	44.37	(16.7)%	(0.7)%	49.47	44.21	11.9%
Total (boe/d)	7,429	8,917	7,479	(16.7)%	(0.7)%	8,336	7,452	11.9%
Activity								
Capital expenditures	3,028	4,577	5,056	(33.8)%	(40.1)%	13,954	15,029	(7.2)%
Acquisitions	—	—	2,874			908	5,773	
Financial results								
Sales	18,729	28,327	41,793	(33.9)%	(55.2)%	87,642	112,979	(22.4)%
Royalties	(279)	(446)	(1,049)	(37.4)%	(73.4)%	(1,339)	(2,644)	(49.4)%
Operating	(6,396)	(7,686)	(5,812)	(16.8)%	10.0%	(22,367)	(19,916)	12.3%
General and administration	(300)	(704)	(320)	(57.4)%	(6.3)%	(1,896)	(1,238)	53.2%
Current income taxes	(462)	(2,575)	1,729	(82.1)%	N/A	(7,237)	(9,069)	(20.2)%
Fund flows from operations	11,292	16,916	36,341	(33.2)%	(68.9)%	54,803	80,112	(31.6)%
Netbacks (\$/boe)								
Sales	27.40	34.91	60.74	(21.5)%	(54.9)%	38.51	55.54	(30.7)%
Royalties	(0.41)	(0.55)	(1.52)	(25.5)%	(73.0)%	(0.59)	(1.30)	(54.6)%
Operating	(9.36)	(9.47)	(8.45)	(1.2)%	10.8%	(9.83)	(9.79)	0.4%
General and administration	(0.44)	(0.87)	(0.47)	(49.4)%	(6.4)%	(0.83)	(0.61)	36.1%
Current income taxes	(0.68)	(3.17)	2.51	(78.5)%	N/A	(3.18)	(4.46)	(28.7)%
Fund flows from operations netback	16.51	20.85	52.81	(20.8)%	(68.7)%	24.08	39.38	(38.9)%
Realized prices								
Condensate (\$/bbl)	69.12	79.10	82.32	(12.6)%	(16.0)%	72.08	77.08	(6.5)%
Natural gas (\$/mcf)	4.49	5.73	10.08	(21.6)%	(55.5)%	6.36	9.22	(31.0)%
Total (\$/boe)	27.40	34.91	60.74	(21.5)%	(54.9)%	38.51	55.54	(30.7)%
Reference prices								
TTF (\$/mcf)	4.40	5.75	10.92	(23.5)%	(59.7)%	6.08	10.00	(39.2)%
TTF (€/mcf)	3.00	3.82	7.18	(21.5)%	(58.2)%	4.07	6.50	(37.4)%

Production

- Q3 2019 production decreased 17% from the prior quarter primarily due to a planned turnaround and unexpected downtime to repair a gas compressor, which extended the length of the turnaround. Quarterly production was relatively consistent year-over year.

Activity review

- We are currently in the process of drilling the Weststellingwerf well (0.5 net), representing our first drilling activity in the Netherlands since 2017, and we expect drilling to be completed before the end of the year.

Sales

- The price of our natural gas in the Netherlands is based on the TTF index.
- For the three and nine months ended September 30, 2019, sales on a per unit basis decreased versus all comparable periods, consistent with decreases in the TTF reference price.

Royalties

- In the Netherlands, certain wells are subject to overriding royalties while some wells are subject to royalties that take effect only when specified production levels are exceeded. As such, royalty expense may fluctuate from period to period depending on the amount of production from those wells.
- Royalties in Q3 2019 represented 1.5% of sales. Effective March 1, 2019, certain royalty rights were acquired which resulted in lower royalties.

Transportation

- Our production in the Netherlands is not subject to transportation expense as gas is sold at the plant gate.

Operating

- Q3 2019 operating expense per boe was relatively consistent with the prior quarter. Compared to the same quarter of the prior year, Q3 2019 operating expense per boe was higher due to timing of activity.
- For the nine months ended September 30, 2019, operating expense per boe remained consistent as compared to the same period in 2018.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- In the Netherlands, current income taxes are applied to taxable income, after eligible deductions and a 10% uplift deduction applied to operating expenses, eligible general and administration expenses, and tax deductions for depletion and asset retirement obligations, at a tax rate of 50%.
- Full year effective tax rates are estimated each quarter based on forecasted commodity prices and operational results. The estimated full year effective tax rate is applied on a pro-rata basis to quarterly results. As such, fluctuations between the reporting periods occur due to changes in estimated tax rates.
- For 2019, the effective rate on current taxes, inclusive of corporate allocations, is expected to be between 6% to 8% of pre-tax fund flows from operations. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.

Germany Business Unit

Overview

- Entered Germany in 2014 through the acquisition of a non-operated natural gas producing property.
- Executed a significant exploration license farm-in agreement in 2015 and acquired operated producing properties in 2016.
- Producing assets consist of seven gas and eight oil producing fields with extensive infrastructure in place.
- Significant land position of approximately 1.2 million net acres (97% undeveloped).

Operational and financial review

Germany business unit (\$M except as indicated)	Q3 2019	Q2 2019	Q3 2018	Q3/19 vs. Q2/19	Q3/19 vs. Q3/18	YTD 2019	YTD 2018	2019 vs. 2018
Production								
Crude oil (bbls/d)	845	1,047	1,019	(19.3)%	(17.1)%	956	1,035	(7.6)%
Natural gas (mmcf/d)	14.54	14.56	14.88	(0.1)%	(2.3)%	15.26	15.23	0.2%
Total (boe/d)	3,269	3,474	3,498	(5.9)%	(6.5)%	3,500	3,573	(2.0)%
Sales								
Crude oil (bbls/d)	864	982	929	(12.0)%	(7.0)%	965	1,097	(12.0)%
Natural gas (mmcf/d)	14.54	14.56	14.88	(0.1)%	(2.3)%	15.26	15.23	0.2%
Total (boe/d)	3,287	3,409	3,408	(3.6)%	(3.6)%	3,509	3,635	(3.5)%
Production mix (% of total)								
Crude oil	26%	30%	29%			27%	29%	
Natural gas	74%	70%	71%			73%	71%	
Activity								
Capital expenditures	4,229	9,234	6,497	(54.2)%	(34.9)%	16,507	11,226	47.0%
Acquisitions	947	4,751	959			6,114	959	
Gross wells drilled	—	2.00	—			2.00	—	
Net wells drilled	—	0.71	—			0.71	—	
Financial results								
Sales	11,320	15,093	21,052	(25.0)%	(46.2)%	45,781	60,552	(24.4)%
Royalties	(952)	(1,502)	(2,448)	(36.6)%	(61.1)%	(4,677)	(5,436)	(14.0)%
Transportation	(1,709)	(773)	(1,191)	121.1%	43.5%	(4,154)	(4,968)	(16.4)%
Operating	(6,433)	(5,212)	(4,863)	23.4%	32.3%	(17,565)	(16,433)	6.9%
General and administration	(2,436)	(2,146)	(2,073)	13.5%	17.5%	(6,495)	(5,093)	27.5%
Fund flows from operations	(210)	5,460	10,477	N/A	N/A	12,890	28,622	(55.0)%
Netbacks (\$/boe)								
Sales	37.43	48.65	67.15	(23.1)%	(44.3)%	47.79	61.02	(21.7)%
Royalties	(3.15)	(4.84)	(7.81)	(34.9)%	(59.7)%	(4.88)	(5.48)	(10.9)%
Transportation	(5.65)	(2.49)	(3.80)	126.9%	48.7%	(4.34)	(5.01)	(13.4)%
Operating	(21.27)	(16.80)	(15.51)	26.6%	37.1%	(18.33)	(16.56)	10.7%
General and administration	(8.05)	(6.92)	(6.61)	16.3%	21.8%	(6.78)	(5.13)	32.2%
Fund flows from operations netback	(0.69)	17.60	33.42	N/A	N/A	13.46	28.84	(53.3)%
Realized prices								
Crude oil (\$/bbl)	76.51	87.05	92.45	(12.1)%	(17.2)%	80.80	86.71	(6.8)%
Natural gas (\$/mcf)	3.92	5.52	9.61	(29.0)%	(59.2)%	5.88	8.32	(29.3)%
Total (\$/boe)	37.43	48.65	67.15	(23.1)%	(44.3)%	47.79	61.02	(21.7)%
Reference prices								
Dated Brent (US \$/bbl)	61.94	68.82	75.27	(10.0)%	(17.7)%	64.65	72.13	(10.4)%
Dated Brent (\$/bbl)	81.80	92.05	98.37	(11.1)%	(16.8)%	85.93	92.87	(7.5)%
TTF (\$/mcf)	4.40	5.75	10.92	(23.5)%	(59.7)%	6.08	10.00	(39.2)%
TTF (€/mcf)	3.00	3.82	7.18	(21.5)%	(58.2)%	4.07	6.50	(37.4)%

Production

- Q3 2019 production decreased 6% from the prior quarter and 7% year-over-year due to unplanned downtime on several operated and non-operated assets, partially offset by contributions from successful workovers performed earlier this year.

Activity review

- During Q3 2019, we continued to evaluate tie-in alternatives for the Burgmoor Z5 (46% working interest) well, which was tested early in the third quarter of 2019.
- For the remainder of 2019, we plan to continue evaluating and performing workover opportunities on our operated asset base.

Sales

- The price of our natural gas in Germany is based on the NCG and GPL indexes, which are both highly correlated to the TTF benchmark. Crude oil in Germany is priced with reference to Dated Brent.
- For the three and nine months ended September 30, 2019, sales per boe decreased versus all comparable periods due to decreases in crude oil and natural gas reference prices.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Royalties as a percentage of sales was relatively consistent for the three and nine months ended September 30, 2019 versus all comparable periods.

Transportation

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer and deliver crude oil to the refinery.
- Transportation expense in Q3 2019 increased compared to both Q2 2019 and Q3 2018 due to prior period adjustments.
- Transportation expense for the nine months ended September 30, 2019 was lower than the comparable period in the prior year largely due to lower gas transportation costs following a credit received in Q2 2019 from the transportation network operator.

Operating

- Operating expense on a dollar and per unit basis for the three and nine months ended September 30, 2019 increased versus all comparable periods due to timing of activities.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- As a result of our tax pools in Germany, we do not expect to incur current income taxes for 2019 in the Germany Business Unit. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments

Ireland Business Unit

Overview

- Entered Ireland in 2009 with an investment in the offshore Corrib gas field.
- The Corrib gas field is located offshore northwest Ireland and comprises of six offshore wells, offshore and onshore sales and transportation pipeline segments, as well as a natural gas processing facility.
- In Q4 2018, Vermilion assumed operatorship of the Corrib Natural Gas Project (the "Corrib Project") and increased its ownership stake by 1.5% to 20% following the completion of a strategic partnership with Canada Pension Plan Investment Board ("CPPIB").

Operational and financial review

Ireland business unit (\$M except as indicated)	Q3 2019	Q2 2019	Q3 2018	Q3/19 vs. Q2/19	Q3/19 vs. Q3/18	YTD 2019	YTD 2018	2019 vs. 2018
Production and sales								
Natural gas (mmcf/d)	43.21	49.21	51.38	(12.2)%	(15.9)%	48.01	56.23	(14.6)%
Total (boe/d)	7,202	8,201	8,563	(12.2)%	(15.9)%	8,002	9,372	(14.6)%
Activity								
Capital expenditures	354	84	(50)	321.4%	N/A	449	84	434.5%
Financial results								
Sales	16,722	25,936	50,228	(35.5)%	(66.7)%	82,450	151,765	(45.7)%
Transportation	(1,130)	(1,155)	(1,460)	(2.2)%	(22.6)%	(3,451)	(4,014)	(14.0)%
Operating	(3,136)	(2,631)	(3,354)	19.2%	(6.5)%	(9,577)	(10,869)	(11.9)%
General and administration	(1,436)	(242)	(3,597)	493.4%	(60.1)%	(2,007)	(6,349)	(68.4)%
Fund flows from operations	11,020	21,908	41,817	(49.7)%	(73.6)%	67,415	130,533	(48.4)%
Netbacks (\$/boe)								
Sales	25.24	34.75	63.76	(27.4)%	(60.4)%	37.74	59.32	(36.4)%
Transportation	(1.71)	(1.55)	(1.85)	10.3%	(7.6)%	(1.58)	(1.57)	0.6%
Operating	(4.73)	(3.53)	(4.26)	34.0%	11.0%	(4.38)	(4.25)	3.1%
General and administration	(2.17)	(0.32)	(4.57)	578.1%	(52.5)%	(0.92)	(2.48)	(62.9)%
Fund flows from operations netback	16.63	29.35	53.08	(43.3)%	(68.7)%	30.86	51.02	(39.5)%
Reference prices								
NBP (\$/mcf)	4.50	5.44	10.95	(17.3)%	(58.9)%	6.08	10.12	(39.9)%
NBP (€/mcf)	3.07	3.62	7.20	(15.2)%	(57.4)%	4.07	6.58	(38.1)%

Production

- Q3 2019 production decreased 12% from the prior quarter and 16% year-over-year due to planned and unplanned downtime at the Corrib natural gas processing facility and natural decline.

Activity review

- During Q3 2019, we completed a planned plant turnaround.
- For the remainder of 2019, we will continue to evaluate further optimization opportunities as we progress through our first year as operator of the Corrib Project.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Sales per boe for the three and nine months ended September 30, 2019 decreased versus all comparable periods consistent with decreases in the NBP reference price.

Royalties

- Our production in Ireland is not subject to royalties.

Transportation

- Transportation expense in Ireland relates to payments under a ship-or-pay agreement.
- Transportation expense for Q3 2019 versus Q2 2019 remained relatively consistent.
- Transportation expense for the three and nine months ended September 30, 2019 decreased versus the comparable periods in the prior year due to a lower ship-or-pay obligation in the current year.

Operating

- Q3 2019 operating expense increased compared to Q2 2019 due to timing of activity.
- For the three and nine months ended September 30, 2019, operating expense decreased versus the comparable periods in the prior year due to Vermilion's focus on cost management following our appointment as operator in December 2018.

General and administration

- Fluctuations in general and administration expense versus all comparable periods is primarily due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- Given the significant level of investment in Corrib and the resulting tax pools, we do not expect to incur current income taxes in the Ireland Business Unit for the foreseeable future.

Australia Business Unit

Overview

- Entered Australia in 2005.
- Hold a 100% operated working interest in the Wandoo field, located approximately 80 km offshore on the northwest shelf of Australia.
- Production is operated from two off-shore platforms and originates from 20 producing wells including five dual lateral wells for a total of 25 producing laterals.
- Wells that utilize horizontal legs (ranging in length from 500 to 3,000 plus metres) are located 600m below the seabed in approximately 55m of water depth.

Operational and financial review

Australia business unit (\$M except as indicated)	Q3 2019	Q2 2019	Q3 2018	Q3/19 vs. Q2/19	Q3/19 vs. Q3/18	YTD 2019	YTD 2018	2019 vs. 2018
Production								
Crude oil (bbls/d)	5,564	6,689	4,704	(16.8)%	18.3%	6,037	4,601	31.2%
Sales								
Crude oil (bbls/d)	6,517	4,737	3,935	37.6%	65.6%	6,334	4,322	46.6%
Inventory (mbbls)								
Opening crude oil inventory	196	18	139			189	134	
Crude oil production	512	609	433			1,648	1,256	
Crude oil sales	(600)	(431)	(362)			(1,729)	(1,180)	
Closing crude oil inventory	108	196	210			108	210	
Activity								
Capital expenditures	2,995	2,239	16,061	33.8%	(81.4)%	24,098	31,878	(24.4)%
Gross wells drilled	—	—	—			2.00	—	
Net wells drilled	—	—	—			2.00	—	
Financial results								
Sales	56,188	42,848	35,848	31.1%	56.7%	162,618	111,382	46.0%
Operating	(11,876)	(8,092)	(11,585)	46.8%	2.5%	(41,372)	(37,442)	10.5%
General and administration	(1,260)	(1,164)	(1,020)	8.2%	23.5%	(3,463)	(3,527)	(1.8)%
Current income taxes	(6,222)	(12,084)	(3,101)	(48.5)%	100.6%	(32,406)	(13,625)	137.8%
Fund flows from operations	36,830	21,508	20,142	71.2%	82.9%	85,377	56,788	50.3%
Netbacks (\$/boe)								
Sales	93.71	99.39	99.01	(5.7)%	(5.4)%	94.04	94.39	(0.4)%
Operating	(19.81)	(18.77)	(32.00)	5.5%	(38.1)%	(23.92)	(31.73)	(24.6)%
General and administration	(2.10)	(2.70)	(2.82)	(22.2)%	(25.5)%	(2.00)	(2.99)	(33.1)%
PRRT	(9.72)	(19.18)	0.70	(49.3)%	N/A	(14.16)	(6.14)	130.6%
Corporate income taxes	(0.66)	(8.85)	(9.27)	(92.5)%	(92.9)%	(4.58)	(5.41)	(15.3)%
Fund flows from operations netback	61.42	49.89	55.62	23.1%	10.4%	49.38	48.12	2.6%
Reference prices								
Dated Brent (US \$/bbl)	61.94	68.82	75.27	(10.0)%	(17.7)%	64.65	72.13	(10.4)%
Dated Brent (\$/bbl)	81.80	92.05	98.37	(11.1)%	(16.8)%	85.93	92.87	(7.5)%

Production

- Q3 2019 production decreased 17% quarter-over-quarter primarily due to well management and unplanned vessel maintenance on the Wandoo platform. Production increased 18% year-over-year primarily due to the production contribution from the two (2.0 net) well drilling program completed at the end of January 2019.
- Production volumes are managed to targets while meeting customer demands and the requirements of long-term supply agreements.

Activity review

- In 2019, we will continue to focus on adding value through asset optimization and proactive maintenance.

Sales

- Crude oil in Australia is priced with reference to Dated Brent and from 2012 to 2018 has sold at an average premium of US\$3-5 per bbl to Dated Brent.
- Q3 2019 sales increased compared to Q2 2019 due to higher sales volumes resulting from increased liftings in the current quarter. This increase in sales volumes was partially offset by lower sales per boe due to a decrease in the Dated Brent reference price.
- Sales increased for the three and nine months ended September 30, 2019 versus the comparable periods in 2018, despite decreases in the Dated Brent reference pricing, due to the timing of sales in the relevant periods.

Royalties and transportation

- Our production in Australia is not subject to royalties or transportation expense as crude oil is sold directly at the Wandoo B platform.

Operating

- Q3 2019 operating expense increased compared to Q2 2019 on a dollar and per boe basis due to increased maintenance activity during the quarter.
- For the three and nine months ended September 30, 2019 versus the comparable periods in the prior year, operating expense per unit decreased primarily due to lower diesel usage and lower helicopter costs.

General and administration

- Fluctuations in general and administration expense for all comparable periods are primarily due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- In Australia, current income taxes include both PRRT and corporate income taxes. PRRT is a profit based tax applied at a rate of 40% on sales less eligible expenditures, including operating expenses and capital expenditures. Corporate income taxes are applied at a rate of 30% on taxable income after eligible deductions, which include PRRT paid.
- Full year effective tax rates are estimated each quarter based on forecasted commodity prices and operational results. The estimated full year effective tax rate is applied on a pro-rata basis to quarterly results. As such, fluctuations between the reporting periods occur due to changes in estimated tax rates.
- For 2019, the effective rate on current taxes, inclusive of corporate allocations, is expected to be between 24% to 26% of pre-tax fund flows from operations. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.

United States Business Unit

Overview

- Entered the United States in 2014 and acquired additional producing assets in the Hilight field in 2018.
- Interests include approximately 146,800 net acres of land (70% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Tight oil development targeting the Turner Sands at depths of approximately 1,500m (East Finn) and 2,600m (Hilight).

Operational and financial review

United States business unit (\$M except as indicated)	Q3 2019	Q2 2019	Q3 2018	Q3/19 vs. Q2/19	Q3/19 vs. Q3/18	YTD 2019	YTD 2018	2019 vs. 2018
Production and sales								
Crude oil (bbls/d)	2,722	2,483	1,461	9.6%	86.3%	2,319	900	157.7%
NGLs (bbls/d)	1,140	754	714	51.2%	59.7%	942	268	251.5%
Natural gas (mmcf/d)	6.38	7.06	4.82	(9.6)%	32.4%	6.45	1.81	256.4%
Total (boe/d)	4,925	4,414	2,979	11.6%	65.3%	4,335	1,469	195.1%
Production mix (% of total)								
Crude oil	55%	56%	49%			53%	61%	
NGLs	23%	17%	24%			22%	18%	
Natural gas	22%	27%	27%			25%	21%	
Activity								
Capital expenditures	21,064	12,964	11,386	62.5%	85.0%	54,064	37,956	42.4%
Acquisitions	1,964	1,217	187,987			3,224	188,066	
Gross wells drilled	4.00	1.00	—			8.00	5.00	
Net wells drilled	4.00	1.00	—			8.00	5.00	
Financial results								
Sales	19,227	18,355	14,551	4.8%	32.1%	52,479	23,840	120.1%
Royalties	(4,874)	(4,583)	(3,444)	6.3%	41.5%	(13,390)	(6,017)	122.5%
Operating	(4,400)	(3,542)	(2,633)	24.2%	67.1%	(11,374)	(3,573)	218.3%
General and administration	(2,005)	(1,571)	(2,397)	27.6%	(16.4)%	(5,467)	(4,910)	11.3%
Fund flows from operations	7,948	8,659	6,077	(8.2)%	30.8%	22,248	9,340	138.2%
Netbacks (\$/boe)								
Sales	42.43	45.69	53.10	(7.1)%	(20.1)%	44.34	59.45	(25.4)%
Royalties	(10.76)	(11.41)	(12.57)	(5.7)%	(14.4)%	(11.31)	(15.00)	(24.6)%
Operating	(9.71)	(8.82)	(9.61)	10.1%	1.0%	(9.61)	(8.91)	7.9%
General and administration	(4.43)	(3.91)	(8.75)	13.3%	(49.4)%	(4.62)	(12.24)	(62.3)%
Fund flows from operations netback	17.53	21.55	22.17	(18.7)%	(20.9)%	18.80	23.30	(19.3)%
Realized prices								
Crude oil (\$/bbl)	68.91	70.98	87.34	(2.9)%	(21.1)%	69.60	84.23	(17.4)%
NGLs (\$/bbl)	9.44	17.49	29.22	(46.0)%	(67.7)%	16.72	29.53	(43.4)%
Natural gas (\$/mcf)	1.67	1.74	2.01	(4.0)%	(16.9)%	2.34	2.01	16.4%
Total (\$/boe)	42.43	45.69	53.10	(7.1)%	(20.1)%	44.34	59.45	(25.4)%
Reference prices								
WTI (US \$/bbl)	56.45	59.81	69.50	(5.6)%	(18.8)%	57.06	66.75	(14.5)%
WTI (\$/bbl)	74.55	80.00	90.83	(6.8)%	(17.9)%	75.84	85.95	(11.8)%
Henry Hub (US \$/mcf)	2.23	2.64	2.90	(15.5)%	(23.1)%	2.67	2.90	(7.9)%
Henry Hub (\$/mcf)	2.94	3.53	3.80	(16.7)%	(22.6)%	3.55	3.74	(5.1)%

Production

- Q3 2019 production increased 12% from the prior quarter due to production contributions from our first half 2019 Hilight drilling campaign, as four (4.0 net) wells were completed and brought on production during the quarter. Quarterly production increased 65% year-over-year primarily due to the production associated with an acquisition we completed in August 2018 and the results of our 2019 drilling program to date.

Activity

- During Q3 2019, we drilled four (4.0 net) Turner horizontal wells in the Hilight field and brought all four wells on production.
- In 2019, we have drilled eight (8.0 net) Turner horizontal wells in the Hilight field.

Sales

- The price of our crude oil in the United States is directly linked to WTI and subject to local market differentials within the United States. The price of our natural gas in the United States is based on the Henry Hub index.
- For the three and nine months ended September 30, 2019 versus all comparable periods, sales increased due to increased production, which more than offset the decrease in sales per boe resulting from lower commodity prices.

Royalties

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax.
- For the three and nine months ended September 30, 2019, royalties as a percentage of sales were relatively consistent versus all comparable periods.

Operating

- Q3 2019 operating expense increased compared to Q2 2019 primarily due to expenditure timing.
- For the three and nine months ended September 30, 2019 compared to the same periods in the prior year, operating expense increased primarily due to incremental expenses associated with the year-over-year production increase.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the incremental staffing of the United States corporate office, timing of expenditures, and allocations from our corporate segment.

Current income taxes

- As a result of our tax pools in the United States, we do not expect to incur current income taxes in the United States Business Unit for the foreseeable future.

Corporate

Overview

- Our Corporate segment includes costs related to our global hedging program, financing expenses, and general and administration expenses that are primarily incurred in Canada and are not directly related to the operations of our business units. Gains or losses relating to Vermilion's global hedging program are allocated to Vermilion's business units for statutory reporting and income tax purposes.
- Results of our activities in Central and Eastern Europe are also included in the Corporate segment.

Operational and financial review

Corporate (\$M)	Q3 2019	Q2 2019	Q3 2018	YTD 2019	YTD 2018
Production and sales					
Natural gas (mmcf/d)	—	—	1.17	—	0.39
Total (boe/d)	—	—	195	—	66
Activity					
Capital expenditures	8,107	8,755	1,619	20,470	8,065
Acquisitions	—	—	207	—	207
Gross wells drilled	3.00	3.00	—	6.00	1.00
Net wells drilled	3.00	2.30	—	5.30	1.00
Financial results					
Sales	—	—	1,083	—	1,083
Royalties	—	—	(279)	—	(279)
Sales of purchased commodities	41,449	75,335	—	146,323	—
Purchased commodities	(41,449)	(75,335)	—	(146,323)	—
Operating	(2)	(9)	(201)	(242)	(201)
General and administration recovery (expense)	2,957	1,086	854	3,423	(3,713)
Current income taxes	(250)	(104)	(862)	(504)	(1,159)
Interest expense	(19,661)	(21,568)	(19,772)	(62,208)	(51,932)
Realized gain (loss) on derivatives	36,968	14,191	(37,365)	61,507	(82,939)
Realized foreign exchange loss	(3,348)	(1,569)	(3,100)	(6,967)	(5,651)
Realized other income	372	191	177	7,447	608
Fund flows from operations	17,036	(7,782)	(59,465)	2,456	(144,183)

Production review

- There was no production from our CEE business unit during the third quarter of 2019.

Activity review

- In Q3 2019, we drilled one (1.0 net) natural gas exploration well in Croatia and one (1.0 net) natural gas exploration well in Hungary.
- During the third quarter, we were provisionally awarded the SA-07 license in Croatia, adding approximately 500,000 net acres to our portfolio in the country. The new license is contiguous with our existing land position and will bring our total licensed acreage to approximately 2.4 million net acres.

Purchased commodities

- Purchased commodities and the associated sales relate to amounts purchased from third parties, primarily to manage positions on pipelines. There is no net impact on fund flows from operations.

General and administration

- Fluctuations in general and administration expense for the three and nine months ended September 30, 2019 versus all comparable periods were due to allocations to the various business unit segments.

Current income taxes

- Taxes in our corporate segment relate to holding companies that pay current taxes in foreign jurisdictions.

Interest expense

- Interest expense in Q3 2019 decreased versus Q2 2019 as a result of cross currency interest rate swaps entered into in Q2 2019 that a Euro debt obligation and lower our interest costs.
- For the three months ended September 30, 2019, interest expense remained relatively consistent with the comparative period in 2018.
- For the nine months ended September 30, 2019, interest expense increased versus the comparative period in 2018 due to higher drawings on the revolving credit facility, partially offset by the impact of the aforementioned cross currency interest rate swaps.

Realized gain or loss on derivatives

- The realized gain on derivatives for the three and nine months ended September 30, 2019 is related primarily to receipts for our crude oil hedges.
- A listing of derivative positions as at September 30, 2019 is included in "Supplemental Table 2" of this MD&A.

Realized other income

- Realized other income recognized in the nine months ended September 30, 2019, relates primarily to amounts received pursuant to a negotiated settlement of a legal matter in Canada.

Financial Performance Review

(\$M except per share)	Q3 2019	Q2 2019	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017
Petroleum and natural gas sales	391,935	428,043	481,083	456,939	508,411	394,498	318,269	317,341
Net earnings (loss)	(10,229)	2,004	39,547	323,373	(15,099)	(61,364)	24,740	8,645
Net earnings (loss) per share								
Basic	(0.07)	0.01	0.26	2.12	(0.10)	(0.46)	0.20	0.07
Diluted	(0.07)	0.01	0.26	2.10	(0.10)	(0.46)	0.20	0.07

The following table shows the calculation of fund flows from operations:

	Q3 2019		Q2 2019		Q3 2018		YTD 2019		YTD 2018	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Petroleum and natural gas sales	391,935	43.04	428,043	46.40	508,411	57.90	1,301,061	46.79	1,221,178	54.64
Royalties	(41,490)	(4.56)	(38,113)	(4.13)	(53,786)	(6.13)	(122,987)	(4.42)	(108,293)	(4.85)
Petroleum and natural gas revenues	350,445	38.48	389,930	42.27	454,625	51.77	1,178,074	42.37	1,112,885	49.79
Transportation	(19,426)	(2.13)	(20,750)	(2.25)	(13,721)	(1.56)	(56,876)	(2.05)	(34,949)	(1.56)
Operating	(105,192)	(11.55)	(101,881)	(11.04)	(97,758)	(11.13)	(329,495)	(11.85)	(244,544)	(10.94)
General and administration	(13,652)	(1.50)	(15,697)	(1.70)	(13,234)	(1.51)	(42,407)	(1.53)	(39,115)	(1.75)
PRRT	(5,826)	(0.64)	(8,268)	(0.90)	254	0.03	(24,494)	(0.88)	(7,246)	(0.32)
Corporate income taxes	(4,527)	(0.50)	(11,841)	(1.28)	(9,401)	(1.07)	(32,118)	(1.16)	(30,807)	(1.38)
Interest expense	(19,661)	(2.16)	(21,568)	(2.34)	(19,772)	(2.25)	(62,208)	(2.24)	(51,932)	(2.32)
Realized gain (loss) on derivative instruments	36,968	4.06	14,191	1.54	(37,365)	(4.26)	61,507	2.21	(82,939)	(3.71)
Realized foreign exchange loss	(3,348)	(0.37)	(1,569)	(0.17)	(3,100)	(0.35)	(6,967)	(0.25)	(5,651)	(0.25)
Realized other income	372	0.04	191	0.02	177	0.02	7,447	0.27	608	0.03
Fund flows from operations	216,153	23.73	222,738	24.15	260,705	29.69	692,463	24.89	616,310	27.59

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.

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

	Q3 2019	Q2 2019	Q3 2018	YTD 2019	YTD 2018
Fund flows from operations	216,153	222,738	260,705	692,463	616,310
Equity based compensation	(15,564)	(14,593)	(13,056)	(53,000)	(43,767)
Unrealized gain (loss) on derivative instruments	17,817	(30,605)	(75,829)	(27,065)	(163,770)
Unrealized foreign exchange gain (loss)	(50,679)	41,798	(23,044)	14,377	(26,877)
Unrealized other expense	(347)	(69)	(203)	(621)	(597)
Accretion	(8,701)	(8,147)	(8,041)	(24,834)	(23,014)
Depletion and depreciation	(174,077)	(184,131)	(166,343)	(535,237)	(434,621)
Deferred tax	5,169	(24,987)	10,712	(34,761)	24,613
Net (loss) earnings	(10,229)	2,004	(15,099)	31,322	(51,723)

Fluctuations in net income 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, including the Vermilion Incentive Plan ("VIP"), a security-based compensation arrangement ("Five-Year Compensation Arrangement"), and the Deferred Share Unit Plan ("DSU Plan").

Equity based compensation expense in Q3 2019 was relatively consistent to Q2 2019. For the three and nine months ended September 30, 2019, equity based compensation expense increased versus the comparable periods in 2018 primarily due to a higher value of outstanding share awards in 2019.

Unrealized gain or loss on derivative instruments

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

For the three and nine months ended September 30, 2019, we recognized an unrealized gain on derivative instruments of \$17.8 million and an unrealized loss on derivative instruments of \$27.1 million. The unrealized gain of \$17.8 million in the three months ended September 30, 2019 resulted primarily from an unrealized gain of \$37.6 million on our cross currency interest rate swaps, partially offset by an unrealized loss of \$19.8 million on our commodity derivative instruments, primarily due to an increase in European natural gas price forecasts and realized gains in the quarter.

The unrealized loss on derivative instruments of \$27.1 million for the nine months ended September 30, 2019 resulted primarily from our USD-to-CAD cross currency interest rate swaps. These USD-to-CAD cross currency interest rate swaps are entered into on a monthly basis 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.

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 2019, unrealized foreign exchange gains and losses primarily results 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 gains (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 above).
- The translation of our USD denominated senior unsecured notes for the period from December 31, 2018 to June 12, 2019. Effective June 12, 2019, the USD senior notes were hedged by a USD-to-CAD cross currency interest rate swap.

For the three months ended September 30, 2019, the impact of the Euro weakening against the Canadian dollar resulted in a \$12.3 million unrealized loss on our intercompany loans. This was coupled with an unrealized loss of \$38.4 million on our USD borrowings from our revolving credit facility (which is offset by the aforementioned unrealized gain on derivative instruments).

For the nine months ended September 30, 2019, the impact of the Euro weakening against the Canadian dollar resulted in a \$34.9 million unrealized loss on our intercompany loans. This was partially offset by a \$19.8 million unrealized gain on our USD denominated senior unsecured notes for the period from December 31, 2018 to June 12, 2019 (when the USD senior notes were hedged by a USD-to-CAD cross currency interest rate swap) and a \$29.5 million unrealized gain on our USD borrowings from our revolving credit facility (which is offset by the aforementioned unrealized loss on derivative instruments).

As at September 30, 2019, a \$0.01 appreciation of the Euro against the Canadian dollar would result in a \$2.0 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 \$0.1 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. Accretion expense in Q3 2019 was relatively consistent with Q2 2019 and Q3 2018. For the nine months ended September 30, 2019, accretion expense increased versus the comparable period in 2018, primarily attributable to new obligations recognized following acquisition activity in 2018.

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, future development costs, and relative production mix.

Depletion and depreciation on a per boe basis for Q3 2019 of \$19.12 remained relatively consistent from \$19.96 in Q2 2019. For the three and nine months ended September 30, 2019, depletion and depreciation on a per boe basis of \$19.12 and \$19.25 respectively, remained relatively consistent with \$18.95 and \$19.45 in the respective comparable periods in 2018.

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 de-recognition or re-recognition of deferred tax assets, and changes in enacted or substantively enacted tax rates.

For the three and nine months ended September 30, 2019, deferred tax recovery of \$5.2 million and deferred tax expense of \$34.8 million, respectively, was recognized. The recovery primarily related to deferred taxes on unrealized foreign exchange gains. The nine months ended expense primarily related to the de-recognition of a portion of non-expiring tax loss pools in Ireland as there is uncertainty as to Vermilion's ability to fully utilize such losses based on commodity price forecasts as at September 30, 2019.

Financial Position Review

Balance sheet strategy

We believe that our balance sheet supports our defined growth initiatives and our focus is on managing and maintaining a conservative balance sheet. To ensure that our balance sheet continues to support our defined growth initiatives, we regularly review whether our forecast of fund flows from operations is sufficient to finance planned capital expenditures, dividends, 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 with debt (including borrowing using the unutilized capacity of our existing revolving credit facility), issue equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

To ensure that we maintain a conservative balance sheet, we monitor the ratio of net debt to fund flows from operations.

We remain focused on maintaining and strengthening our balance sheet by aligning our exploration and development capital budget with forecasted fund flows from operations to target a payout ratio (a non-GAAP financial measure) of approximately 100%. We continually monitor for changes in forecasted fund flows from operations as a result of changes to forward commodity prices and as appropriate, we will adjust our exploration and development capital plans. As a result of our focus on this payout ratio target, we intend for the ratio of net debt to fund flows from operations to trend towards 1.5 over time.

Net debt

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

(\$M)	As at	
	Sep 30, 2019	Dec 31, 2018
Long-term debt	1,954,471	1,796,207
Current liabilities	398,233	563,199
Current assets	(350,834)	(429,877)
Net debt	2,001,870	1,929,529
Ratio of net debt to trailing twelve months fund flows from operations	2.19	2.30

As at September 30, 2019, net debt increased to \$2.0 billion (December 31, 2018 - \$1.9 billion) primarily due to the impact of increased borrowings on the revolving credit facility to fund our capital program, coupled with a \$24.3 million decrease in net current derivative assets. The ratio of net debt to trailing twelve months fund flows from operations decreased to 2.19 (December 31, 2018 - 2.30) as the increase to net debt was offset by higher trailing twelve months fund flows from operations.

Long-term debt

The balances recognized on our balance sheet are as follows:

(\$M)	As at	
	Sep 30, 2019	Dec 31, 2018
Revolving credit facility	1,561,669	1,392,206
Senior unsecured notes	392,802	404,001
Long-term debt	1,954,471	1,796,207

Revolving Credit Facility

In Q2 2019, we negotiated an amendment to our \$2.1 billion revolving credit facility to extend the maturity to May 31, 2023. The amendment included changes to the financial covenants, as described below.

As at September 30, 2019, Vermilion had in place a bank revolving credit facility maturing May 31, 2023 with terms and outstanding positions as follows:

(\$M)	As at	
	Sep 30, 2019	Dec 31, 2018
Total facility amount	2,100,000	1,800,000
Amount drawn	(1,561,669)	(1,392,206)
Letters of credit outstanding	(10,600)	(15,400)
Unutilized capacity	527,731	392,394

As at September 30, 2019, the revolving credit facility was subject to the following financial covenants:

Financial covenant	Limit	As at	
		Sep 30, 2019	Dec 31, 2018
Consolidated total debt to consolidated EBITDA	Less than 4.0	1.90	1.72
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	1.52	1.34
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	13.36	14.57

In Q2 2019, our financial covenants were updated to replace the consolidated total senior debt to total capitalization covenant with an interest coverage covenant (calculated as consolidated EBITDA to consolidated interest expense) and to add provisions relating to our liability management ratings in Alberta and Saskatchewan. If our security adjusted liability management ratings fall below specified limits in a province, a portion of the asset retirement obligations are included in the definitions of consolidated total debt and consolidated total senior debt. An event of default occurs if our security adjusted liability management ratings breach additional lower limits for a period greater than 90 days. As of September 30, 2019, 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.

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 excluding interest on operating leases as defined under IAS 17.

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, at its option, redeem the senior unsecured notes prior to maturity as follows:

- Prior to March 15, 2020, Vermilion may redeem up to 35% of the original principal amount of the senior unsecured notes with the proceeds of certain equity offerings by the Company at a redemption price of 105.625% of the principal amount, plus any accrued and unpaid interest to but excluding the applicable redemption date.
- Prior to March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at a price equal to 100% of the principal amount of the senior unsecured notes, plus a "make-whole" premium and any accrued and unpaid interest.
- On or after March 15, 2020, 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.

Year	Redemption price
2020	104.219%
2021	102.813%
2022	101.406%
2023 and thereafter	100.000%

Cross currency interest rate swaps

On June 12, 2019, Vermilion entered into a series of cross currency interest rate swaps with a syndicate of banks. The cross currency interest rate swaps mature March 15, 2025 and include regular cash receipts and payments on March 15 and September 15 of each year. On a net basis, the cross currency interest swaps result in Vermilion receiving US dollar interest and principal amounts equal to the interest and principal payments under the US \$300.0 million of senior unsecured notes. In exchange, Vermilion will make interest and principal payments equal to €265.0 million at a rate of 3.275%.

The cross currency interest rate swaps were executed as two separate sets of instruments, wherein Vermilion:

- Receives US dollar interest and principal amounts equal to US\$300.0 million of debt at 5.625% interest and pays Canadian dollar interest and principal amounts equal to \$398.5 million of debt at 5.40% interest.
- Receives Canadian dollar interest and principal amounts equal to \$398.5 million of debt at 5.40% interest and pays Euro interest and principal amounts equal to €265.0 million at a rate of 3.275%.

Shareholders' capital

Beginning with the April 2018 dividend paid on May 15, 2018, we increased our monthly dividend by 7%, to \$0.23 per share from \$0.215 per share. The dividend increase in Q2 2018 was our fourth dividend increase (previously Vermilion's distribution in the income trust era) since we began paying a distribution in 2003.

In total, dividends declared for the nine months ended September 30, 2019 were \$319.6 million.

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 onwards	\$0.230

Our policy with respect to dividends is to be conservative and maintain a low ratio of dividends to fund flows from operations. During low commodity price cycles, we will initially maintain dividends and allow the ratio to rise. Should low commodity price cycles remain for an extended period of time, we will evaluate the necessity of changing the level of dividends, taking into consideration capital development requirements, debt levels, and acquisition opportunities.

Although we expect to be able to maintain our current dividend, fund flows from operations may not be sufficient to fund cash dividends, capital expenditures, and asset retirement obligations. We will evaluate our ability to finance any shortfall with debt, issuances of equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

On August 7, 2019, the Toronto Stock Exchange ("TSX") approved the notice of our intention to commence a normal course issuer bid ("the NCIB"). The NCIB allows Vermilion to purchase up to 7,750,000 common shares (representing approximately 5% of shares outstanding common shares) beginning August 9, 2019 and ending August 8, 2020. Any common shares that are purchased under the NCIB will be canceled upon their purchase. As at September 30, 2019, no shares have been purchased pursuant to the NCIB.

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount (\$M)
Balance at December 31, 2018	152,704	4,008,828
Shares issued for the Dividend Reinvestment Plan	898	24,737
Vesting of equity based awards	1,223	45,636
Equity based compensation	437	13,553
Share-settled dividends on vested equity based awards	243	7,987
Balance as at September 30, 2019	155,505	4,100,741

As at September 30, 2019, there were approximately 2.3 million equity based compensation awards outstanding. As at October 30, 2019, there were approximately 155.7 million common shares issued and outstanding.

Asset Retirement Obligations

As at September 30, 2019, asset retirement obligations were \$633.5 million compared to \$650.2 million as at December 31, 2018.

The decrease in asset retirement obligations is largely attributable to the impact of the Euro weakening against the Canadian dollar. This decrease was partially offset by an overall decrease in the discount rates applied to the abandonment obligation and accretion expense. Vermilion calculated the present value of the obligations using a credit-adjusted risk-free rate, calculated using a credit spread of 4.9% (2018 - 4.0%). The risk-free rates used as inputs to discount the obligations were as follows:

	Sep 30, 2019	Dec 31, 2018
Canada	1.5 %	2.2%
France	0.5 %	1.6%
Netherlands	(0.5)%	0.4%
Germany	(0.1)%	0.9%
Ireland	0.4 %	1.6%
Australia	1.3 %	2.6%
USA	2.1 %	2.7%

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.

Risk Management

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, 2018 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 three and nine months ended September 30, 2019. 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, 2018, available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

Internal Control Over Financial Reporting

There was 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.

Vermilion has limited the scope of design controls and procedures ("DC&P") and internal controls over financial reporting to exclude controls, policies and procedures of Vermilion E&P Ireland Limited (which was acquired in December 2018). The scope limitation is in accordance with section 3.3(1) (b) of NI 52-109 which allows an issuer to limit the design of DC&P and ICFR to exclude controls, policies, and procedures of a business that the issuer acquired not more than 365 days before the end of the fiscal period.

The table below presents the summary financial information of Vermilion E&P Ireland Limited included in Vermilion's financial statements as at and for the nine months ended September 30, 2019:

(\$MM)	As at September 30, 2019
Non-current assets	42
Non-current liabilities	(4)
Net assets	135

(\$MM)	Nine months ended September 30, 2019
Revenue	5
Net earnings	1

Recently Adopted Accounting Pronouncements

Definition of a Business - Amendments to IFRS 3 "Business Combinations"

Vermilion elected to early adopt the amendments to IFRS 3 "Business Combinations" effective January 1, 2019, which will be applied prospectively to acquisitions that occur on or after January 1, 2019. The amendments introduce an optional concentration test, narrow the definitions of a business and outputs, and clarify that an acquired set of activities and assets must include an input and a substantive process that together significantly contribute to the ability to create outputs. These amendments did not result in changes to Vermilion's accounting policies for applying the acquisition method.

Disclosure Controls and Procedures

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

As of September 30, 2019, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded and certified that our disclosure controls and procedures are effective.

Supplemental Table 1: Netbacks

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

	Q3 2019			YTD 2019			Q3 2018	YTD 2018
	Liquids \$/bbl	Natural Gas \$/mcf	Total \$/boe	Liquids \$/bbl	Natural Gas \$/mcf	Total \$/boe	Total \$/boe	Total \$/boe
Canada								
Sales	54.69	1.16	34.94	57.37	1.58	37.64	46.02	39.89
Royalties	(7.19)	(0.09)	(4.44)	(7.39)	0.04	(4.24)	(6.40)	(4.86)
Transportation	(2.52)	(0.18)	(1.93)	(2.41)	(0.18)	(1.87)	(1.72)	(1.55)
Operating	(12.64)	(1.34)	(10.75)	(12.93)	(1.38)	(11.02)	(10.52)	(9.50)
Operating netback	32.34	(0.45)	17.82	34.64	0.06	20.51	27.38	23.98
General and administration			(1.08)			(0.96)	(0.25)	(0.32)
Fund flows from operations netback			16.74			19.55	27.13	23.66
France								
Sales	79.89	—	79.89	83.98	1.76	83.69	95.46	91.27
Royalties	(11.18)	—	(11.23)	(11.33)	(0.75)	(11.31)	(12.08)	(11.56)
Transportation	(6.05)	—	(6.05)	(6.21)	—	(6.18)	(1.91)	(2.39)
Operating	(14.77)	—	(14.77)	(15.24)	—	(15.18)	(13.00)	(13.51)
Operating netback	47.89	—	47.84	51.20	1.01	51.02	68.47	63.81
General and administration			(3.31)			(3.56)	(3.19)	(3.45)
Current income taxes			(3.34)			(5.54)	(6.54)	(4.72)
Fund flows from operations netback			41.19			41.92	58.74	55.64
Netherlands								
Sales	69.12	4.49	27.40	72.08	6.36	38.51	60.74	55.54
Royalties	—	(0.07)	(0.41)	—	(0.10)	(0.59)	(1.52)	(1.30)
Operating	—	(1.58)	(9.36)	—	(1.66)	(9.83)	(8.45)	(9.79)
Operating netback	69.12	2.84	17.63	72.08	4.60	28.09	50.77	44.45
General and administration			(0.44)			(0.83)	(0.47)	(0.61)
Current income taxes			(0.68)			(3.18)	2.51	(4.46)
Fund flows from operations netback			16.51			24.08	52.81	39.38
Germany								
Sales	76.51	3.92	37.43	80.80	5.88	47.79	67.15	61.02
Royalties	(2.50)	(0.56)	(3.15)	(4.08)	(0.86)	(4.88)	(7.81)	(5.48)
Transportation	(16.54)	(0.30)	(5.65)	(11.97)	(0.24)	(4.34)	(3.80)	(5.01)
Operating	(25.75)	(3.28)	(21.27)	(24.66)	(2.66)	(18.33)	(15.51)	(16.56)
Operating netback	31.72	(0.22)	7.36	40.09	2.12	20.24	40.03	33.97
General and administration			(8.05)			(6.78)	(6.61)	(5.13)
Fund flows from operations netback			(0.69)			13.46	33.42	28.84
Ireland								
Sales	—	4.20	25.24	—	6.29	37.74	63.76	59.32
Transportation	—	(0.28)	(1.71)	—	(0.26)	(1.58)	(1.85)	(1.57)
Operating	—	(0.79)	(4.73)	—	(0.73)	(4.38)	(4.26)	(4.25)
Operating netback	—	3.13	18.80	—	5.30	31.78	57.65	53.50
General and administration			(2.17)			(0.92)	(4.57)	(2.48)
Fund flows from operations netback			16.63			30.86	53.08	51.02

	Q3 2019			YTD 2019			Q3 2018	YTD 2018
	Liquids \$/bbl	Natural Gas \$/mcf	Total \$/boe	Liquids \$/bbl	Natural Gas \$/mcf	Total \$/boe	Total \$/boe	Total \$/boe
Australia								
Sales	93.71	—	93.71	94.04	—	94.04	99.01	94.39
Operating	(19.81)	—	(19.81)	(23.92)	—	(23.92)	(32.00)	(31.73)
PRRT ⁽¹⁾	(9.72)	—	(9.72)	(14.16)	—	(14.16)	0.70	(6.14)
Operating netback	64.18	—	64.18	55.96	—	55.96	67.71	56.52
General and administration			(2.10)			(2.00)	(2.82)	(2.99)
Corporate income taxes			(0.66)			(4.58)	(9.27)	(5.41)
Fund flows from operations netback			61.42			49.38	55.62	48.12
United States								
Sales	51.36	1.67	42.43	54.33	2.34	44.34	53.10	59.45
Royalties	(13.02)	(0.43)	(10.76)	(13.82)	(0.62)	(11.31)	(12.57)	(15.00)
Operating	(10.25)	(1.29)	(9.71)	(9.96)	(1.42)	(9.61)	(9.61)	(8.91)
Operating netback	28.09	(0.05)	21.96	30.55	0.30	23.42	30.92	35.54
General and administration			(4.43)			(4.62)	(8.75)	(12.24)
Fund flows from operations netback			17.53			18.80	22.17	23.30
Total Company								
Sales	64.23	2.43	43.04	66.75	3.56	46.79	57.90	54.64
Realized hedging (loss) gain	2.39	1.05	4.06	1.53	0.51	2.21	(4.26)	(3.71)
Royalties	(7.46)	(0.11)	(4.56)	(7.62)	(0.06)	(4.42)	(6.13)	(4.85)
Transportation	(2.96)	(0.17)	(2.13)	(2.89)	(0.16)	(2.05)	(1.56)	(1.56)
Operating	(13.90)	(1.40)	(11.55)	(14.60)	(1.39)	(11.85)	(11.13)	(10.94)
PRRT ⁽¹⁾	(1.12)	—	(0.64)	(1.57)	—	(0.88)	0.03	(0.32)
Operating netback	41.18	1.80	28.22	41.60	2.46	29.80	34.85	33.26
General and administration			(1.50)			(1.53)	(1.51)	(1.75)
Interest expense			(2.16)			(2.24)	(2.25)	(2.32)
Realized foreign exchange loss			(0.37)			(0.25)	(0.35)	(0.25)
Other income			0.04			0.27	0.02	0.03
Corporate income taxes			(0.50)			(1.16)	(1.07)	(1.38)
Fund flows from operations netback			23.73			24.89	29.69	27.59

⁽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. The weighted average price for the portfolio of options listed below may not have the same payoff profile as the individual contracts. As such, the presentation of the weighted average prices is purely for indicative purposes.

The following tables outline Vermilion's outstanding risk management positions as at September 30, 2019:

Crude Oil	Period	Exercise date ⁽¹⁾	Currency	Bought Put Volume (bbl/d)	Weighted Average Bought Put Price / bbl	Sold Call Volume (bbl/d)	Weighted Average Sold Call Price / bbl	Sold Put Volume (bbl/d)	Weighted Average Sold Put Price / bbl	Swap Volume (bbl/d)	Weighted Average Swap Price / bbl
Dated Brent											
Swap	Oct 2019 - Dec 2019		CAD	—	—	—	—	—	—	1,350	91.76
3-Way Collar	Oct 2019 - Dec 2019		USD	1,500	63.03	1,500	71.67	1,500	55.00	—	—
3-Way Collar	Oct 2019 - Jun 2020		USD	1,000	65.00	1,000	72.50	1,000	55.00	—	—
Swap	Oct 2019 - Dec 2019		USD	—	—	—	—	—	—	4,250	69.32
Swaption	Jan 2020 - Dec 2020	Dec 31, 2019	USD	—	—	—	—	—	—	5,000	61.55
WTI											
Swap	Oct 2019 - Dec 2019		CAD	—	—	—	—	—	—	1,050	81.41
3-Way Collar	Oct 2019 - Dec 2019		USD	1,250	55.20	1,250	64.05	1,250	46.00	—	—
3-Way Collar	Oct 2019 - Mar 2020		USD	2,500	57.40	2,000	62.38	2,500	50.20	—	—
3-Way Collar	Oct 2019 - Jun 2020		USD	6,750	52.78	3,500	60.09	6,750	44.33	—	—
Swap	Oct 2019 - Dec 2019		USD	—	—	—	—	—	—	2,000	60.00
Swap	Oct 2019 - Mar 2020		USD	—	—	—	—	—	—	1,500	59.17

North American Gas	Period	Exercise date ⁽¹⁾	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Sold Put Volume (mmbtu/d)	Weighted Average Sold Put Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap Price / mmbtu
AECO											
Collar	Nov 2019 - Mar 2020		CAD	10,426	1.58	10,426	2.56	—	—	—	—
Swap	Apr 2020 - Oct 2020		CAD	—	—	—	—	—	—	10,426	1.39
AECO Basis (AECO less NYMEX Henry Hub)											
Swap	Oct 2019		USD	—	—	—	—	—	—	10,000	(1.65)
Swap	Oct 2019 - Jun 2020		USD	—	—	—	—	—	—	2,500	(0.93)
Swap	Nov 2019 - Mar 2020		USD	—	—	—	—	—	—	30,000	(0.94)
Swap	Apr 2020 - Oct 2020		USD	—	—	—	—	—	—	50,000	(1.12)
Swap	Nov 2020 - Mar 2021		USD	—	—	—	—	—	—	30,000	(1.11)
Swap	Apr 2021 - Oct 2021		USD	—	—	—	—	—	—	35,000	(1.10)
Swap	Nov 2021 - Mar 2022		USD	—	—	—	—	—	—	30,000	(1.10)
Swap	Apr 2022 - Oct 2022		USD	—	—	—	—	—	—	35,000	(1.09)

⁽¹⁾ The sold swaption instrument allows the counterparty, at the specified date, to enter into a derivative instrument contract with Vermilion at the above detailed terms.

European Gas	Period	Exercise date ⁽¹⁾	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Sold Put Volume (mmbtu/d)	Weighted Average Sold Put Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap Price / mmbtu
NBP											
3-Way Collar	Oct 2019 - Dec 2019		EUR	17,197	4.97	17,197	5.65	17,197	3.79	—	—
3-Way Collar ⁽²⁾	Oct 2019 - Mar 2020		EUR	7,370	5.57	7,370	6.74	7,370	4.10	—	—
3-Way Collar ⁽²⁾	Oct 2019 - Dec 2020		EUR	7,370	4.96	7,370	5.76	7,370	3.74	—	—
3-Way Collar ⁽²⁾	Jan 2020 - Dec 2020		EUR	22,111	5.19	22,111	5.78	22,111	4.05	—	—
3-Way Collar ⁽²⁾	Jan 2020 - Dec 2021		EUR	12,284	5.41	12,284	5.44	12,284	3.90	—	—
3-Way Collar ⁽²⁾	Oct 2020 - Mar 2021		EUR	7,370	5.57	9,827	6.16	7,370	4.10	—	—
3-Way Collar ⁽²⁾	Oct 2020 - Jun 2022		EUR	12,283	5.33	12,283	6.10	12,283	3.60	—	—
3-Way Collar ⁽²⁾	Jan 2021 - Dec 2021		EUR	17,197	5.53	17,197	5.98	17,197	4.19	—	—
3-Way Collar ⁽²⁾	Oct 2021 - Mar 2022		EUR	7,370	5.57	7,370	6.74	7,370	4.10	—	—
Swaption	Jan 2020 - Mar 2020	Dec 31, 2019	EUR	—	—	—	—	—	—	2,047	7.33
Swaption	Oct 2020 - Jun 2022	Jun 30, 2020	EUR	—	—	—	—	—	—	2,457	5.86
Swaption	Oct 2020 - Jun 2022	Sep 30, 2020	EUR	—	—	—	—	—	—	2,457	6.15
Swaption	Jan 2021 - Sep 2022	Jun 30, 2020	EUR	—	—	—	—	—	—	2,457	5.86
Swaption	Jan 2021 - Sep 2022	Jun 30, 2020	USD	—	—	—	—	—	—	2,457	6.45

NBP Basis (NBP less NYMEX Henry Hub)

Collar	Oct 2019 - Sep 2020		USD	7,500	2.07	7,500	4.00	—	—	—	—
Collar	Jan 2020 - Mar 2020		USD	2,500	3.50	2,500	4.00	—	—	—	—
Collar	Jan 2020 - Dec 2020		USD	7,500	3.15	7,500	3.97	—	—	—	—
Collar	Oct 2020 - Dec 2020		USD	2,500	3.50	2,500	4.00	—	—	—	—

European Gas	Period	Exercise date	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Sold Put Volume (mmbtu/d)	Weighted Average Sold Put Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap Price / mmbtu
TTF											
3-Way Collar	Oct 2019 - Dec 2019		EUR	23,339	4.86	23,339	5.59	23,339	3.36	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—
3-Way Collar	Apr 2020 - Sep 2020		EUR	2,457	5.33	2,457	5.86	2,457	3.81	—	—
Put Spread	Apr 2020 - Sep 2020		EUR	3,685	5.35	—	—	3,685	3.52	—	—
Swap	Oct 2019 - Dec 2019		EUR	—	—	—	—	—	—	15,969	4.92
Swap	Apr 2020 - Jun 2020		EUR	—	—	—	—	—	—	4,913	5.54
Swap	Jul 2020		EUR	—	—	—	—	—	—	4,913	5.36
Swap	Sep 2020		EUR	—	—	—	—	—	—	4,913	5.54
TTF Basis (TTF less NYMEX Henry Hub)											
Collar	Apr 2020 - Sep 2020		USD	2,500	3.50	2,500	4.00	—	—	—	—
Swap	Apr 2020 - Sep 2020		USD	—	—	—	—	—	—	5,000	3.21

Cross Currency Interest Rate		Receive Notional Amount		Receive Rate	Pay Notional Amount		Pay Rate
Swap	Oct 2019	1,139,217,113	USD	LIBOR + 1.70%	1,504,900,000	CAD	CDOR + 1.27%
Swap	Jun 2019 - Mar 2025	300,000,000	USD	5.625%	265,048,910	EUR	3.275%

VET Equity Swaps		Notional Amount		Share Volume
Swap	Oct 2019 - Oct 2021	33,688,050	CAD	1,500,000
Swap	Oct 2019 - Sep 2021	47,202,300	CAD	2,250,000

⁽¹⁾ The sold swaption instrument allows the counterparty, at the specified date, to enter into a derivative instrument contract with Vermilion at the above detailed terms.

⁽²⁾ The weighted average sold call price in the 3-way collars contains sold calls priced in USD that have been translated to EUR using foreign exchange forward rates as at September 30, 2019.

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification (\$M)	Q3 2019	Q2 2019	Q3 2018	YTD 2019	YTD 2018
Drilling and development	117,123	75,149	142,116	389,563	343,483
Exploration and evaluation	10,756	17,458	4,069	32,976	11,151
Capital expenditures	127,879	92,607	146,185	422,539	354,634

Acquisitions	4,657	8,623	193,677	29,307	307,622
Shares issued for acquisition	—	—	—	—	1,235,221
Long-term debt net of working capital assumed	—	—	4,496	—	213,893
Acquisitions	4,657	8,623	198,173	29,307	1,756,736

By category (\$M)	Q3 2019	Q2 2019	Q3 2018	YTD 2019	YTD 2018
Drilling, completion, new well equip and tie-in, workovers and recompletions	93,681	70,636	118,317	338,875	283,364
Production equipment and facilities	28,722	12,323	26,964	58,490	53,330
Seismic, studies, land and other	5,476	9,648	904	25,174	17,940
Capital expenditures	127,879	92,607	146,185	422,539	354,634
Acquisitions	4,657	8,623	198,173	29,307	1,756,736
Total capital expenditures and acquisitions	132,536	101,230	344,358	451,846	2,111,370

Capital expenditures by country (\$M)	Q3 2019	Q2 2019	Q3 2018	YTD 2019	YTD 2018
Canada	69,963	29,083	89,837	227,101	187,646
France	18,139	25,671	15,779	65,896	62,750
Netherlands	3,028	4,577	5,056	13,954	15,029
Germany	4,229	9,234	6,497	16,507	11,226
Ireland	354	84	(50)	449	84
Australia	2,995	2,239	16,061	24,098	31,878
United States	21,064	12,964	11,386	54,064	37,956
Corporate	8,107	8,755	1,619	20,470	8,065
Total capital expenditures	127,879	92,607	146,185	422,539	354,634

Acquisitions by country (\$M)	Q3 2019	Q2 2019	Q3 2018	YTD 2019	YTD 2018
Canada	1,746	2,655	6,146	19,061	1,561,731
Netherlands	—	—	2,874	908	5,773
Germany	947	4,751	959	6,114	959
United States	1,964	1,217	187,987	3,224	188,066
Corporate	—	—	207	—	207
Total acquisitions	4,657	8,623	198,173	29,307	1,756,736

In 2019, included in cash expenditures on acquisitions of \$29.3 million is: \$12.2 million net paid to vendors in relation to the purchase of assets from other oil and gas producers; \$3.6 million in asset improvements incurred subsequent to acquisitions for compliance with safety, environmental, and Vermilion's operating standards; \$3.7 million paid to acquire land; \$0.9 million paid to acquire royalty interests, and \$8.9 million relating to the carry component of farm-in arrangements.

Supplemental Table 4: Production

	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18	Q2/18	Q1/18	Q4/17	Q3/17	Q2/17	Q1/17	Q4/16
Canada												
Crude oil & condensate (bbls/d)	27,682	28,844	29,164	29,557	28,477	17,009	9,272	9,703	9,288	9,205	7,987	7,945
NGLs (bbls/d)	6,632	7,352	6,968	6,816	6,126	5,589	5,106	5,235	4,891	3,745	2,670	2,444
Natural gas (mmcf/d)	145.14	151.87	151.37	146.65	136.77	127.32	106.21	107.91	103.92	93.68	85.74	75.12
Total (boe/d)	58,504	61,507	61,360	60,814	57,397	43,817	32,078	32,923	31,499	28,563	24,947	22,910
% of consolidated	60%	60%	59%	60%	59%	55%	46%	45%	46%	43%	38%	38%
France												
Crude oil (bbls/d)	10,347	9,800	11,342	11,317	11,407	11,683	11,037	11,215	10,918	11,368	10,834	11,220
Natural gas (mmcf/d)	—	—	0.77	0.82	—	—	—	—	—	—	0.01	0.38
Total (boe/d)	10,347	9,800	11,470	11,454	11,407	11,683	11,037	11,215	10,918	11,368	10,836	11,283
% of consolidated	11%	10%	11%	11%	12%	14%	16%	15%	16%	17%	17%	19%
Netherlands												
Condensate (bbls/d)	82	100	93	112	84	87	77	105	74	104	76	57
Natural gas (mmcf/d)	44.08	52.90	51.51	51.82	44.37	43.49	44.79	55.66	34.90	31.58	39.92	41.15
Total (boe/d)	7,429	8,917	8,677	8,749	7,479	7,335	7,541	9,381	5,890	5,368	6,729	6,915
% of consolidated	8%	9%	8%	9%	8%	9%	11%	13%	9%	8%	10%	11%
Germany												
Crude oil (bbls/d)	845	1,047	978	913	1,019	1,008	1,078	1,148	1,054	1,047	989	—
Natural gas (mmcf/d)	14.54	14.56	16.71	16.94	14.88	14.63	16.19	18.19	20.12	19.86	19.39	14.80
Total (boe/d)	3,269	3,474	3,763	3,736	3,498	3,447	3,777	4,180	4,407	4,357	4,220	2,467
% of consolidated	3%	3%	4%	4%	4%	4%	5%	6%	7%	6%	7%	4%
Ireland												
Natural gas (mmcf/d)	43.21	49.21	51.71	52.03	51.38	56.56	60.87	56.23	49.04	63.81	64.82	62.92
Total (boe/d)	7,202	8,201	8,619	8,672	8,563	9,426	10,144	9,372	8,173	10,634	10,803	10,486
% of consolidated	7%	8%	8%	9%	9%	12%	14%	13%	12%	16%	17%	17%
Australia												
Crude oil (bbls/d)	5,564	6,689	5,862	4,174	4,704	4,132	4,971	4,993	5,473	6,054	6,581	6,388
% of consolidated	6%	6%	6%	4%	5%	5%	7%	7%	8%	9%	10%	10%
United States												
Crude oil (bbls/d)	2,722	2,483	1,742	1,605	1,461	655	574	667	880	747	365	362
NGLs (bbls/d)	1,140	754	929	998	714	62	20	43	56	76	24	23
Natural gas (mmcf/d)	6.38	7.06	5.89	5.65	4.82	0.40	0.15	0.29	0.64	0.44	0.20	0.18
Total (boe/d)	4,925	4,414	3,653	3,545	2,979	784	618	758	1,043	896	422	414
% of consolidated	5%	4%	4%	3%	3%	1%	1%	1%	2%	1%	1%	1%
Corporate												
Natural gas (mmcf/d)	—	—	—	2.86	1.17	—	—	—	—	—	—	—
Total (boe/d)	—	—	—	477	195	—	—	—	—	—	—	—
% of consolidated	—	—	—	—	—	—	—	—	—	—	—	—
Consolidated												
Liquids (bbls/d)	55,014	57,071	57,078	55,493	53,991	40,225	32,134	33,109	32,634	32,346	29,526	28,439
% of consolidated	57%	55%	55%	55%	56%	50%	46%	45%	48%	48%	46%	47%
Natural gas (mmcf/d)	253.36	275.60	277.96	276.77	253.38	242.40	228.20	238.28	208.62	209.36	210.07	194.54
% of consolidated	43%	45%	45%	45%	44%	50%	54%	55%	52%	52%	54%	53%
Total (boe/d)	97,239	103,003	103,404	101,621	96,222	80,625	70,167	72,821	67,403	67,240	64,537	60,863

	YTD 2019	2018	2017	2016	2015	2014
Canada						
Crude oil & condensate (bbls/d)	28,558	21,154	9,051	9,171	11,357	12,491
NGLs (bbls/d)	6,983	5,914	4,144	2,552	2,301	1,233
Natural gas (mmcf/d)	149.44	129.37	97.89	84.29	71.65	55.67
Total (boe/d)	60,447	48,630	29,510	25,771	25,598	23,001
% of consolidated	61%	56%	45%	40%	46%	47%
France						
Crude oil (bbls/d)	10,493	11,362	11,084	11,896	12,267	11,011
Natural gas (mmcf/d)	0.25	0.21	—	0.44	0.97	—
Total (boe/d)	10,535	11,396	11,085	11,970	12,429	11,011
% of consolidated	10%	13%	16%	19%	23%	22%
Netherlands						
Condensate (bbls/d)	92	90	90	88	99	77
Natural gas (mmcf/d)	49.47	46.13	40.54	47.82	44.76	38.20
Total (boe/d)	8,336	7,779	6,847	8,058	7,559	6,443
% of consolidated	8%	9%	10%	13%	14%	13%
Germany						
Crude oil (bbls/d)	956	1,004	1,060	—	—	—
Natural gas (mmcf/d)	15.26	15.66	19.39	14.90	15.78	14.99
Total (boe/d)	3,500	3,614	4,291	2,483	2,630	2,498
% of consolidated	3%	4%	6%	4%	5%	5%
Ireland						
Natural gas (mmcf/d)	48.01	55.17	58.43	50.89	0.03	—
Total (boe/d)	8,002	9,195	9,737	8,482	5	—
% of consolidated	8%	11%	14%	13%	—	—
Australia						
Crude oil (bbls/d)	6,037	4,494	5,770	6,304	6,454	6,571
% of consolidated	6%	5%	8%	10%	12%	13%
United States						
Crude oil (bbls/d)	2,319	1,078	666	393	231	49
NGLs (bbls/d)	942	452	50	29	7	—
Natural gas (mmcf/d)	6.45	2.78	0.39	0.21	0.05	—
Total (boe/d)	4,335	1,992	781	457	247	49
% of consolidated	4%	2%	1%	1%	—	—
Corporate						
Natural gas (mmcf/d)	—	1.02	—	—	—	—
Total (boe/d)	—	169	—	—	—	—
% of consolidated	—	—	—	—	—	—
Consolidated						
Liquids (bbls/d)	56,380	45,548	31,915	30,433	32,716	31,432
% of consolidated	56%	52%	47%	48%	60%	63%
Natural gas (mmcf/d)	268.88	250.33	216.64	198.55	133.24	108.85
% of consolidated	44%	48%	53%	52%	40%	37%
Total (boe/d)	101,193	87,270	68,021	63,526	54,922	49,573

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 **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)	Q3 2019	Q2 2019	Q3 2018	YTD 2019	YTD 2018
Dividends declared	107,176	106,884	105,192	319,609	282,801
Shares issued for the Dividend Reinvestment Plan	(8,860)	(8,773)	(4,320)	(24,737)	(43,936)
Net dividends	98,316	98,111	100,872	294,872	238,865
Drilling and development	117,123	75,149	142,116	389,563	343,483
Exploration and evaluation	10,756	17,458	4,069	32,976	11,151
Asset retirement obligations settled	3,586	4,907	2,986	12,090	9,203
Payout	229,781	195,625	250,043	729,501	602,702
% of fund flows from operations	106%	88%	96%	105%	98%

('000s of shares)	Q3 2019	Q2 2019	Q3 2018
Shares outstanding	155,505	155,032	152,497
Potential shares issuable pursuant to the VIP	3,755	3,601	3,250
Diluted shares outstanding	159,260	158,633	155,747

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

(\$M)	Twelve Months Ended	
	Sep 30, 2019	Sep 30, 2018
Net earnings (loss)	354,695	(43,078)
Taxes	160,981	(4,516)
Interest expense	83,035	65,642
EBIT	598,711	18,048
Average capital employed	5,426,400	4,500,719
Return on capital employed	11%	—%

DIRECTORS

Lorenzo Donadeo ¹
Calgary, Alberta

Larry J. Macdonald ^{2, 4, 6, 8}
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Carin Knickel ^{6, 8, 12}
Golden, Colorado

Stephen P. Larke ^{4, 6, 12}
Calgary, Alberta

Loren M. Leiker ¹⁰
McKinney, Texas

Timothy R. Marchant ^{7, 10, 11}
Calgary, Alberta

Anthony Marino
Calgary, Alberta

Robert Michaleski ^{4, 5}
Calgary, Alberta

William Roby ^{8, 9, 12}
Katy, Texas

Catherine L. Williams ^{3, 6}
Calgary, Alberta

¹ Chairman of the Board

² Lead Director

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 AND KEY PERSONNEL CANADA

Anthony Marino
President & Chief Executive Officer

Lars Glemser
Vice President & Chief Financial Officer

Mona Jasinski
Executive Vice President, People and Culture

Michael Kaluza
Executive Vice President & Chief Operating Officer

Dion Hatcher
Vice President Canada Business Unit

Terry Hergott
Vice President Marketing

Kyle Preston
Vice President Investor Relations

Jenson Tan
Vice President Business Development

Daniel Goulet
Director Corporate HSE

Jeremy Kalanuk
Director Operations Accounting

Bryce Kremnica
Director Field Operations - Canada Business Unit

Steve Reece
Director Information Technology & Information Systems

Tom Rafter
Director Land - Canada Business Unit

Robert (Bob) J. Engbloom
Corporate Secretary

UNITED STATES

Scott Seatter
Managing Director - U.S. Business Unit

Timothy R. Morris
Director U.S. Business Development - U.S.
Business Unit

EUROPE

Gerard Schut
Vice President European Operations

Sylvain Nothhelfer
Managing Director - France Business Unit

Sven Tummers
Managing Director - Netherlands Business Unit

Bill Liutkus
Managing Director - Germany Business Unit

Darcy Kerwin
Managing Director - Ireland Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business
Unit

AUSTRALIA

Bruce D. Lake
Managing Director - Australia Business Unit

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

HSBC Bank Canada

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

Barclays Bank PLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

The Toronto Stock Exchange ("VET")
The New York Stock Exchange ("VET")

INVESTOR RELATIONS

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E N E R G Y



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