Q3 2019

THIRD QUARTER REPORT

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.

INTERNATIONALLY DIVERSIFIED | SUSTAINABLE GROWTH AND INCOME

VERMILION ENERGY

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.

Abbreviations

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

Highlights

- Q3 2019 production averaged 97,239 boe/d, a decrease of 6% from the prior quarter. The lower production level resulted from a number of plant turnarounds, unplanned downtime, and weather delays. Higher production in the US and France was more than offset by lower production in Canada, Netherlands, Ireland and Australia.

- We have reduced our 2019 capital investment guidance by $10 million to $520 million. With nine months of results in place, we are revising our 2019 annual production guidance range to 100,000 to 101,000 boe/d to account for the unplanned downtime and lower capital investment. We expect to deliver annual production at the mid-point of this revised guidance range, reflecting strong year-over-year production per share growth of 5%.

- Fund flows from operations ("FFO") for Q3 2019 was $216 million ($1.39/basic share[1]), a decrease of 3% from the previous quarter, primarily due to lower production volumes and weaker commodity prices. FFO for Q3 2019 decreased 17% from the same quarter last year as increased production was more than offset by weaker global commodity pricing.

- In the United States, Q3 2019 production averaged 4,925 boe/d, an increase of 12% from the prior quarter, primarily driven by contributions from our 2019 drilling program, which continues to perform above our expectations. New well results were partially offset by a longer-than-expected turnaround at a third-party operated gas plant.

- In Central and Eastern Europe, we drilled one (1.0 net) exploration well in Croatia during Q3 2019, which resulted in a second consecutive gas discovery. The well tested at a rate of 17.2 mmcf/d[2]. We were also provisionally awarded the SA-07 license in Croatia, adding approximately 500,000 net acres to our portfolio, which will bring our total licensed acreage to approximately 2.4 million net acres in the country.

- In France, Q3 2019 production averaged 10,347 boe/d, an increase of 6% from the prior quarter. Production volumes in the Paris Basin were no longer restricted after restart of the Grandpuits refinery in mid-August.

- In Canada, Q3 2019 production averaged 58,504 boe/d, a decrease of 5% from the prior quarter. The decrease was primarily due to planned turnarounds and project delays caused by abnormally wet weather.

- In the Netherlands, Q3 2019 production averaged 7,429 boe/d, a decrease of 17% from the prior quarter, primarily due to a planned turnaround and subsequent repairs required on a gas compression facility.

- In Ireland, Q3 2019 production averaged 43 mmcf/d (7,202 boe/d), a decrease of 12% from the prior quarter. The decrease was primarily due to a planned plant turnaround and unplanned downtime at the Corrib natural gas processing facility. The downtime, which was unrelated to the plant turnaround, was remedied by early October.

- In Australia, Q3 2019 production averaged 5,564 bbl/d, a decrease of 17% from the previous quarter primarily due to well management and unplanned vessel maintenance on the Wandoo platform.

- Our Board of Directors has approved a 2020 Exploration and Development ("E&D") capital budget of $450 million, with associated production guidance of 100,000 to 103,000 boe/d. Our 2020 budget reflects continued emphasis on returning capital to investors, while still providing modest production growth. Within this budget, we also continue to advance strategic capital projects associated with early-stage exploration and development activities.

- We have elected to phase out the Dividend Reinvestment Plan ("DRIP"), prorating the available DRIP shares by 25% each quarter starting in Q1 2020, until completely eliminated in Q4 2020.

- Vermilion received top quartile rankings for 2019 for our industry sector in both the Sustainalytics ESG Rating and SAM (formerly known as RobecoSAM) annual Corporate Sustainability Assessment ("CSA"). These agencies analyze sustainability performance across economic, environmental, governance and social criteria, and the CSA is also the basis of the Dow Jones Sustainability Indices. Our 2019 Sustainability Report is available on our corporate website at: http://sustainability.vermilionenergy.com.

(1) Non-GAAP Financial Measure. Please see the "Non-GAAP Financial Measures" section of the accompanying Management's Discussion and Analysis.

(2) Berak-01 well (100% working interest) tested at a rate of 17.2 mmcf/d during a four-hour flow period with a stabilized flowing wellhead pressure of 908 psi on a 0.875 inch diameter choke. A final shut in wellhead pressure of 1,186 psi was recorded following the flow test. The flow test continued an additional 12 hours at reduced choke sizes to minimize flaring. No formation water was produced during the test. The well logged 21 feet of net gas pay with an average porosity of 32% from the Upper Miocene Pannonian sandstone occurring within a gross measured depth interval of 3,006-3,033 feet. Test results are not necessarily indicative of long-term performance or ultimate recovery.

($M except as indicated)	Q3 2019	Q2 2019	Q3 2018	YTD 2019	YTD 2018
Financial					
Petroleum and natural gas sales	**391,935**	428,043	508,411	**1,301,061**	1,221,178
Fund flows from operations	**216,153**	222,738	260,705	**692,463**	616,310
Fund flows from operations ($/basic share) (1)	**1.39**	1.44	1.71	**4.49**	4.51
Fund flows from operations ($/diluted share) (1)	**1.39**	1.42	1.69	**4.45**	4.46
Net earnings (loss)	**(10,229)**	2,004	(15,099)	**31,322**	(51,723)
Net earnings (loss) ($/basic share)	**(0.07)**	0.01	(0.10)	**0.20**	(0.38)
Capital expenditures	**127,879**	92,607	146,185	**422,539**	354,634
Acquisitions	**4,657**	8,623	198,173	**29,307**	1,756,736
Asset retirement obligations settled	**3,586**	4,907	2,986	**12,090**	9,203
Cash dividends ($/share)	**0.690**	0.690	0.690	**2.070**	2.025
Dividends declared	**107,176**	106,884	105,192	**319,609**	282,801
% of fund flows from operations	**50%**	48%	40%	**46%**	46%
Net dividends (1)	**98,316**	98,111	100,872	**294,872**	238,865
% of fund flows from operations	**45%**	44%	39%	**43%**	39%
Payout (1)	**229,781**	195,625	250,043	**729,501**	602,702
% of fund flows from operations	**106%**	88%	96%	**105%**	98%
Net debt	**2,001,870**	1,950,509	2,034,086	**2,001,870**	2,034,086
Net debt to trailing twelve months fund flows from operations	**2.19**	2.03	2.55	**2.19**	2.55
Operational					
Production					
Crude oil and condensate (bbls/d)	**47,242**	48,964	47,152	**48,455**	36,318
NGLs (bbls/d)	**7,772**	8,107	6,839	**7,925**	5,878
Natural gas (mmcf/d)	**253.36**	275.60	253.38	**268.88**	241.42
Total (boe/d)	**97,239**	103,003	96,222	**101,193**	82,433
Average realized prices					
Crude oil and condensate ($/bbl)	**73.45**	79.46	85.84	**75.38**	84.98
NGLs ($/bbl)	**6.14**	11.25	27.97	**13.25**	26.61
Natural gas ($/mcf)	**2.43**	3.09	5.35	**3.56**	5.30
Production mix (% of production)					
% priced with reference to WTI	**39%**	38%	37%	**38%**	30%
% priced with reference to Dated Brent	**19%**	18%	18%	**18%**	21%
% priced with reference to AECO	**26%**	26%	26%	**26%**	26%
% priced with reference to TTF and NBP	**16%**	18%	19%	**18%**	23%
Netbacks ($/boe)					
Operating netback (1)	**28.22**	29.62	34.85	**29.80**	33.26
Fund flows from operations netback	**23.73**	24.15	29.69	**24.89**	27.59
Operating expenses	**11.55**	11.04	11.13	**11.85**	10.94
General and administration expenses	**1.50**	1.70	1.51	**1.53**	1.75
Average reference prices					
WTI (US $/bbl)	**56.45**	59.81	69.50	**57.06**	66.75
Edmonton Sweet index (US $/bbl)	**51.79**	55.19	62.68	**52.34**	60.69
Saskatchewan LSB index (US $/bbl)	**52.01**	55.54	63.35	**52.81**	60.61
Dated Brent (US $/bbl)	**61.94**	68.82	75.27	**64.65**	72.13
AECO ($/mcf)	**1.06**	1.03	1.19	**1.64**	1.48
NBP ($/mcf)	**4.50**	5.44	10.95	**6.08**	10.12
TTF ($/mcf)	**4.40**	5.75	10.92	**6.08**	10.00
Average foreign currency exchange rates					
CDN $/US $	**1.32**	1.34	1.31	**1.33**	1.29
CDN $/Euro	**1.47**	1.50	1.52	**1.49**	1.54
Share information ('000s)					
Shares outstanding - basic	**155,505**	155,032	152,497	**155,505**	152,497
Shares outstanding - diluted (1)	**159,260**	158,633	155,747	**159,260**	155,747
Weighted average shares outstanding - basic	**155,254**	154,795	152,432	**154,326**	136,585
Weighted average shares outstanding - diluted (1)	**155,421**	156,844	153,839	**155,673**	138,258

(1) The above table includes non-GAAP financial measures which may not be comparable to other companies. Please see the "Non-GAAP Financial Measures" section of the accompanying Management's Discussion and Analysis.

Message to Shareholders

The third quarter of 2019 continued to be an exceptionally difficult period for energy investors, as the upstream oil and gas sector traded down to multi-year lows and significantly underperformed the broader equity market. Vermilion was not spared. Our stock price declined over 30% during the quarter, bringing our current dividend yield to approximately 14%. While we are certainly disappointed with our share price performance, we would like to stress that Vermilion's dividend policy is not based on the market price of our shares. Our dividend policy is based on the fundamental economic sustainability and free cash flow generation of our business, which remains strong.

The capital markets environment for oil and gas companies has changed dramatically over recent years due to a multitude of factors, including poor investment returns from energy issuers, increased focus on ESG and SRI mandates, and a growing concern about the future of fossil fuels amongst both investors and the general public. This has led to valuation multiple compression across the entire sector with many companies, including Vermilion, trading significantly below their historical valuation metrics. Despite these changing capital market dynamics, the oil and gas sector is a vital contributor to the global economy and will be around for many decades to support the long-term energy transition. During this transition, we believe there is significant value to be realized from responsible energy investment, and that Vermilion is optimally positioned to prosper in this industry and market environment. Our belief in Vermilion is founded in the economic sustainability of our business model and our leadership in environmental sustainability in the upstream oil and gas sector.

Throughout our 25-year history, we have repeatedly made the necessary adjustments to adapt to the changing landscape around us. Our business model has focused on sustainable growth and income, which we have successfully delivered to our shareholders over the years. Vermilion has paid over $39 per share in distributions and dividends since 2003 and generated compounded growth in production per share of over 8% annually since 2012. Our investment cycle time is short with minimal fixed commitments. Consequently, we have flexibility to adjust our investment and growth levels to provide the combination of return of capital and growth which we think will maximize shareholder value in a changing capital market environment. Based on the current market and commodity environment, we believe a strategy that is even more focused on free cash flow generation will create the most value for our shareholders. As such, for 2020, while maintaining our dividend at current levels, we have elected to reduce our production growth rate and to introduce additional flexibility in how we return capital to investors.

This lower growth strategy was embedded in the preparation of our 2020 budget as well as our capital plans for the remainder of 2019. For 2019, we have reduced capital investment by $10 million, and now expect to invest $520 million. As a result of this reduced level of investment and after accounting for higher-than-expected downtime and weather delays, we have correspondingly reduced our 2019 annual production guidance to 100,000 to 101,000 boe/d. We expect to deliver annual production at the mid-point of this revised guidance range, reflecting strong year-over-year production per share growth of 5%. Our Board of Directors has approved a 2020 capital budget of $450 million with associated production guidance of 100,000 to 103,000 boe/d. This budget is designed to deliver modest production growth of about 1%. The 2020 budget includes approximately $20 million of strategic capital associated with early-stage exploration and development activities. These activities will lay the groundwork for future development and production growth from a highly economic asset base.

During the third quarter we received approval from the TSX for a normal course issuer bid ("NCIB"), which will allow us to buy back up to 7.75 million shares. With this approval, we intend to use the NCIB in combination with debt reduction when we have excess free cash flow available (beyond dividends) to enhance per share growth. We will also be phasing out our DRIP over the course of the next year, prorating the available DRIP shares by 25% each quarter starting in Q1 2020 until the DRIP is completely eliminated in Q4 2020. The DRIP has been a shareholder service that we have provided since our first income distribution in 2003, with discounted share purchases offered until 2018. We recognize that the elimination of the DRIP may be a disappointment to some shareholders. Nonetheless, we feel that in an environment of lower trading commissions, the establishment of our NCIB, and lower energy issuer valuation multiples, the elimination of the DRIP is in the best interests of our broad shareholder group.

We remain committed to maximizing value for our shareholders over the long-term through a combination of a sustainable dividend, low financial leverage, share buybacks, and production growth as appropriate. In addition, we will remain disciplined in our acquisition strategy as we continue to evaluate strategic opportunities that fit within our business model and add value for existing shareholders. Our highest financial priority is our balance sheet, and under no circumstance will we do anything that jeopardizes Vermilion's long-term financial stability. We have a robust balance sheet with termed-out borrowing, strong liquidity, and a very low cost of debt. Coupled with low operating leverage due to high margins, a diversified product mix, and a strong hedge position, our balance sheet provides us with the flexibility to weather volatility in commodity prices.

Q3 2019 Operations Review

Our Q3 2019 operational results were impacted by several planned turnarounds, a high level of unplanned downtime, weather related delays and a moderate carry-over impact from the refinery outage in France. As a result, our Q3 2019 production decreased 6% from the prior quarter to 97,239 boe/d, with variances discussed by business unit below. We generated FFO of $216 million in the third quarter, down by 3% from the prior quarter, with positive contributions from hedging gains, lower G&A expense, and lower taxes partially offsetting lower production and commodity prices.

Europe

In France, Q3 2019 production averaged 10,347 boe/d, an increase of 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. Most of our wells in the Paris Basin have returned to pre-shutdown production levels, although some wells continue to clean up and workover activity is continuing to restore full productivity. The net impact from the refinery outage reduced our Q3 2019 production volumes by approximately 400 boe/d. In the Aquitaine Basin, production was consistent with the prior quarter as we successfully completed our 2019 workover campaign, which continues to yield results above our expectations.

In the Netherlands, Q3 2019 production averaged 7,429 boe/d, a decrease of 17% from the prior quarter. The decrease was primarily due to a planned turnaround and unexpected downtime to repair a gas compressor, which extended the length of the turnaround. The combined impact was a reduction in Netherlands production of approximately 1,200 boe/d in Q3 2019. Our facilities have returned to service and production has been restored. 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.

In Ireland, production averaged 43 mmcf/d (7,202 boe/d) in Q3 2019, a decrease of 12% from the prior quarter. The decrease was primarily due to planned and unplanned downtime at the Corrib natural gas processing facility and natural decline. Our planned turnaround was successfully completed as scheduled in mid-September. Later in the month, we identified the need for repairs in one of the plant auxiliary systems which necessitated shutting the plant down for approximately 10 days spanning the end of Q3 and early Q4 2019. The combined impact of the planned and unplanned downtime was approximately 800 boe/d in Q3.

In Germany, production in Q3 2019 averaged 3,269 boe/d, a decrease of 6% from the prior quarter. The decrease was primarily due to unplanned downtime on several operated and non-operated assets, partially offset by contributions from successful workovers performed earlier this year. Following the successful drilling of the Burgmoor Z5 (46% working interest) well, completed early in the third quarter of 2019, we continue to evaluate tie-in alternatives and expect to bring the well on production in late 2020.

In Central and Eastern Europe ("CEE"), we drilled one (1.0 net) natural gas exploration well in Croatia during Q3 2019, which resulted in a second consecutive gas discovery, testing at a rate of 17.2 mmcf/d[(2)]. During the third quarter, we were also provisionally awarded the SA-07 license in Croatia, which is contiguous with our existing land position and will add approximately 500,000 net acres to our portfolio in the country. Vermilion continues to be the largest onshore landholder in Croatia, with total licensed acreage of approximately 2.4 million net acres, including the new SA-07 block. In Hungary, we began tie-in activities for the Mh-21 (0.3 net) and Battonya E-09 (1.0 net) wells, drilled in the second and third quarters of 2019, respectively, and expect to bring them on production during the fourth quarter of 2019.

North America

In Canada, production averaged 58,504 boe/d in Q3 2019, a decrease of 5% from the prior quarter. The decrease was primarily due to planned turnarounds (700 boe/d impact) and project delays caused by abnormally wet weather (2,100 boe/d impact). We drilled or participated in 40 (38.3 net) wells in the third quarter of 2019, all of which were drilled in Saskatchewan, as no drilling in Alberta was possible due to wet conditions throughout the summer. Well activity in Alberta, including tie-in and completions, was delayed until late September due to extremely wet ground, three months later than when we typically resume post-break-up activity. We brought 41 (36.2 net) wells on production in Saskatchewan and three (2.5 net) wells on production in Alberta during the quarter. We have continued to realize capital and operating efficiencies in our southeast Saskatchewan assets, achieving a 10% improvement in drilling, completion, equipping and tie-in (“DCET”) costs on our Q3 2019 open-hole drilling program compared to our Q1 2019 program.

In the United States, Q3 2019 production averaged 4,925 boe/d, representing an increase of 12% from the prior quarter. The increase was primarily driven by production contributions from our 2019 Hilight drilling campaign, as we successfully completed and brought on production four (4.0 net) wells during the third quarter. The increased production was partially offset by planned and unplanned third-party gas plant maintenance, which reduced production by approximately 200 boe/d. The first two wells drilled in the quarter were brought on production in late August and achieved an average peak IP30 rate of approximately 600 boe/d per well (86% oil and NGLs). The other two wells were brought on production at the end of September and are currently producing at an average rate of approximately 500 boe/d per well (92% oil and NGLs). We continue to progress along the learning curve in reducing costs since our Hilight acquisition one year ago, with a 20% DCET cost reduction in our H2 2019 program to-date compared to our H1 2019 program. As a result of these cost savings, we have added two (1.5 net) wells to our 2019 program and plan to drill these wells in Q4 2019.

Australia

In Australia, production averaged 5,564 bbl/d in Q3 2019, a decrease of 17% from the previous quarter, primarily due to well management and unplanned vessel maintenance on the Wandoo platform. We plan to conduct facility upgrades in Q4 2019 to increase fluid handling capacity, which will necessitate a shutdown of the Wandoo platform for an estimated eight days in the fourth quarter of 2019.

2020 Budget

Our Board of Directors has approved an exploration and development capital expenditure budget of $450 million, with associated production guidance of 100,000 to 103,000 boe/d. As previously communicated, we are placing less emphasis on production growth as we navigate the current commodity price and capital markets environment.

We plan to drill 13 (8.7 net) wells in Europe. In addition, we plan to continue significant workover programs in France, Netherlands and Germany, and facility optimization in Ireland. The capital budget includes approximately $20 million of strategic, non-production-adding capital invested to facilitate our long-term future growth plans in Europe.

In North America, our activity will focus on our three core areas of southeast Saskatchewan (light oil), west-central Alberta (condensate-rich natural gas), and the Powder River Basin in Wyoming (light oil). We have made significant progress on improving the capital and operating efficiencies on the North American assets we acquired in 2018, and we plan to continue that trend in 2020.

Assuming WTI oil prices remain at approximately US$55/bbl in 2020, and holding all other commodities at the October 11, 2019 commodity strip, we would more than cover our dividend and capital investment. Excess cash generated beyond our capital program and dividend commitment will be allocated to a combination of debt reduction and share buybacks. Our top financial priorities in 2020 will be balance sheet and dividend protection, and we maintain the capital investment flexibility to reduce capital outlays if required by lower commodity prices.

Europe

In France, our 2020 E&D capital budget of $57 million represents a 23% reduction from our 2019 spending. While we do not intend to invest in any new wells in 2020, we plan to continue with our workover and asset optimization programs in both the Paris and Aquitaine Basins. These workover programs are expected to maintain production at roughly the same level in 2020 as we have averaged in 2019.

Our 2020 E&D budget in the Netherlands of $18 million represents a 22% decrease from 2019. While significant progress has been made on our permitting efforts, we will plan for modest growth in the Netherlands in 2020 as we reschedule our slate of capital projects in the context of a lower corporate growth rate target. We plan to drill or participate in three (0.6 net) wells. Assuming success on the Weststellingwerf well (0.5 net) currently being drilled, we plan to bring this well on production during the first half of 2020. We will continue to advance our well permitting throughout the year in order to compile a backlog of projects for implementation beginning in 2021.

In Ireland, we plan to invest approximately $3 million of E&D capital in 2020 as we continue to focus on facility maintenance and compression optimization.

In Germany, our 2020 E&D capital budget of $18 million represents a decrease of 18% year-over-year. In addition to our planned workover and facility program, we plan to drill sidetracks in three (3.0 net) of our operated oil wells and begin drilling activities on one (0.6 net) exploratory gas prospect.

In Central and Eastern Europe, our 2020 E&D budget will be approximately the same as in 2019, building on the success we had in 2019 and laying the groundwork for future growth. We plan to invest $20 million in E&D capital expenditures in 2020. While the majority of this capital program will be focused on following-up our successful 2019 drilling program, a portion of the budget will be directed to strategic infrastructure investments in Croatia and Slovakia, notably the commencement of construction of natural gas compression facilities in each country. In 2020, we plan to drill six (4.5 net) wells in CEE comprised of two (2.0 net) wells in Croatia, one (1.0 net) well in Hungary and three (1.5 net) wells in Slovakia.

North America

In Canada, we plan to invest $250 million of E&D capital in 2020, a decrease of 14% from our 2019 capital program. We plan to drill 107 (95.5 net) wells in Canada in 2020, comprised of 87 (76.3 net) light oil wells in southeast Saskatchewan and 20 (19.2 net) wells in Alberta. In addition to the drilling program, we will also continue to focus on our waterflood program in southeast Saskatchewan, as well as production and facility optimization opportunities, as we have in previous years.

In the United States, our 2020 E&D capital budget of $59 million represents a 4% increase from our 2019 capital program. We plan to drill 10 (9.6 net) wells on our Hilight asset in Wyoming. This expanded drilling program will allow us to capitalize on the efficiencies we have achieved since the Hilight acquisition and to continue to increase production in the Powder River Basin.

Australia

In Australia, our 2020 E&D budget of $25 million will focus primarily on workovers and facility modifications to increase artificial lift capacity and facility throughput.

E&D Capital Investment by Country

Country	2020 Budget* ($MM)	2019 Budget ($MM)	2020 vs. 2019 % Change	2020 Gross Wells	2020 Net Wells
Canada	**250**	292	(14)%	**107**	**95.5**
France	**57**	74	(23)%	**—**	**—**
Netherlands	**18**	23	(22)%	**3**	**0.6**
Germany	**18**	22	(18)%	**4**	**3.6**
Ireland	**3**	1	200 %	**—**	**—**
Australia	**25**	31	(19)%	**—**	**—**
USA	**59**	57	4 %	**10**	**9.6**
Central and Eastern Europe	**20**	20	— %	**6**	**4.5**
Total E&D Capital Expenditures	**450**	520	(13)%	**130**	**113.8**

E&D Capital Investment by Category

Category	2020 Budget* ($MM)	2019 Budget ($MM)	2020 vs. 2019 % Change
Drilling, completion, new well equipment and tie-in, workovers and recompletions	**350**	380	(8)%
Production equipment and facilities	**70**	100	(30)%
Seismic, land and other	**30**	40	(25)%
Total E&D Capital Expenditures	**450**	520	(13)%

*2020 Budget reflects foreign exchange assumptions of CAD/USD 1.32, CAD/EUR 1.48, and CAD/AUD 0.90.

Dividend Reinvestment Plan

We have elected to phase out the Dividend Reinvestment Plan ("DRIP"), prorating the available DRIP shares by 25% each quarter starting in Q1 2020. It is our intention to increase this proration each quarter throughout next year, such that the DRIP will be eliminated by the fourth quarter of 2020.

Commodity Hedging

Vermilion hedges to manage commodity price exposures and increase the stability of our cash flows, providing additional certainty with regard to the execution of our dividend and capital programs. In aggregate, as of October 29, 2019, we currently have 51% of our expected net-of-royalty production hedged for Q4 2019. More than half of our Q4 2019 corporate hedge position consists of two-way collars and three-way structures, which allow participation in price increases up to contract ceilings. For 2020, approximately one-third of our production is hedged, with 54% of our hedge position in participating structures.

With respect to individual products within our product mix, we have currently hedged 74% of anticipated European natural gas volumes for Q4 2019. We have also hedged 75% of our anticipated full-year 2020 European natural gas volumes at prices which are expected to provide for strong project economics and free cash flows. At present, 47% of our expected Q4 oil production is hedged. For Q4 2019, 51% of our North American natural gas production is priced away from AECO, due to diversification hedges to financially sell at the SoCal Border and at Henry Hub for a portion of our Alberta natural gas production, and because 16% of our North American gas production is located in Saskatchewan and Wyoming.

Sustainability

Vermilion received top quartile rankings for 2019 for our industry sector in both the Sustainalytics ESG Rating and SAM (formerly known as RobecoSAM) annual Corporate Sustainability Assessment ("CSA"). These agencies analyze sustainability performance across economic, environmental, governance and social criteria, and the CSA is also the basis of the Dow Jones Sustainability Indices. We believe the integration of sustainability principles into our business is the right thing to do, increases shareholder return, and reduces long-term risks to our business model. These ratings demonstrate our commitment to maintaining leadership in sustainability and ESG performance. Our 2019 Sustainability Report is available on our corporate website at: http://sustainability.vermilionenergy.com.

(signed "Anthony Marino")

Anthony Marino
President & Chief Executive Officer
October 30, 2019

(1) Non-GAAP Financial Measure. Please see the "Non-GAAP Financial Measures" section of Management's Discussion and Analysis.

(2) Berak-01 well (100% working interest) tested at a rate of 17.2 mmcf/d during a four-hour flow period with a stabilized flowing wellhead pressure of 908 psi on a 0.875 inch diameter choke. A final shut in wellhead pressure of 1,186 psi was recorded following the flow test. The flow test continued an additional 12 hours at reduced choke sizes to minimize flaring. No formation water was produced during the test. The well logged 21 feet of net gas pay with an average porosity of 32% from the Upper Miocene Pannonian sandstone occurring within a gross measured depth interval of 3,006-3,033 feet. Test results are not necessarily indicative of long-term performance or ultimate recovery.

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.

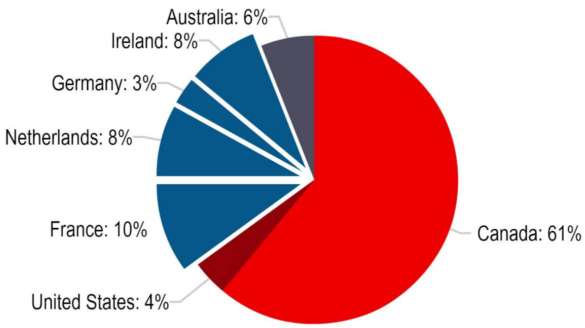
The following table summarizes our guidance:

	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

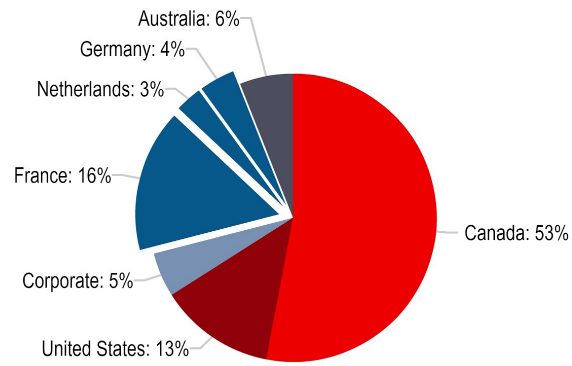
Vermilion's Business

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.

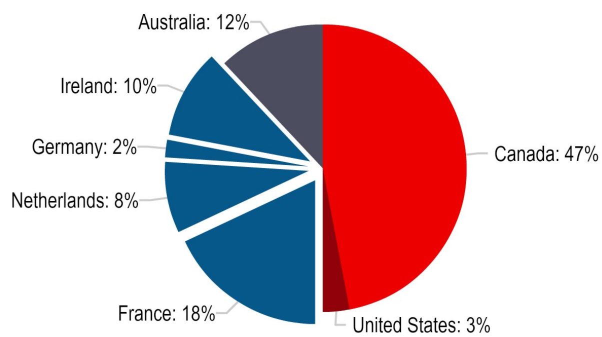
2019 YTD production of 101,193 boe/d by business unit



2019 YTD capital expenditures of $423MM by business unit



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



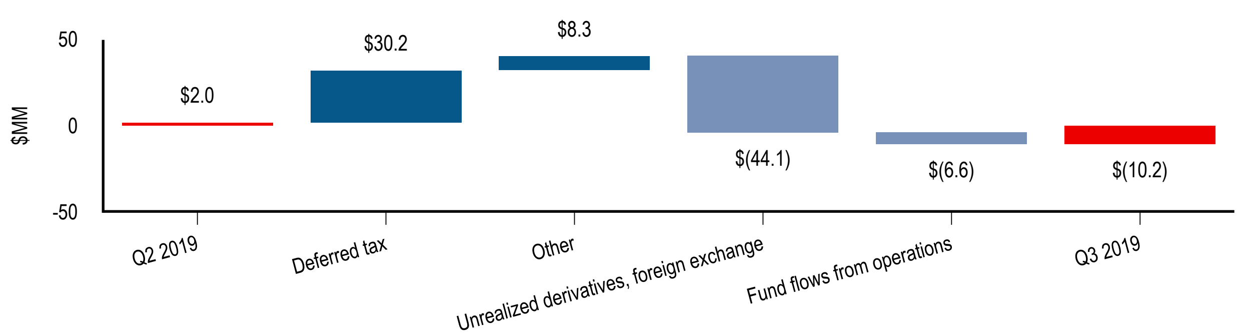
Consolidated Results Overview

	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

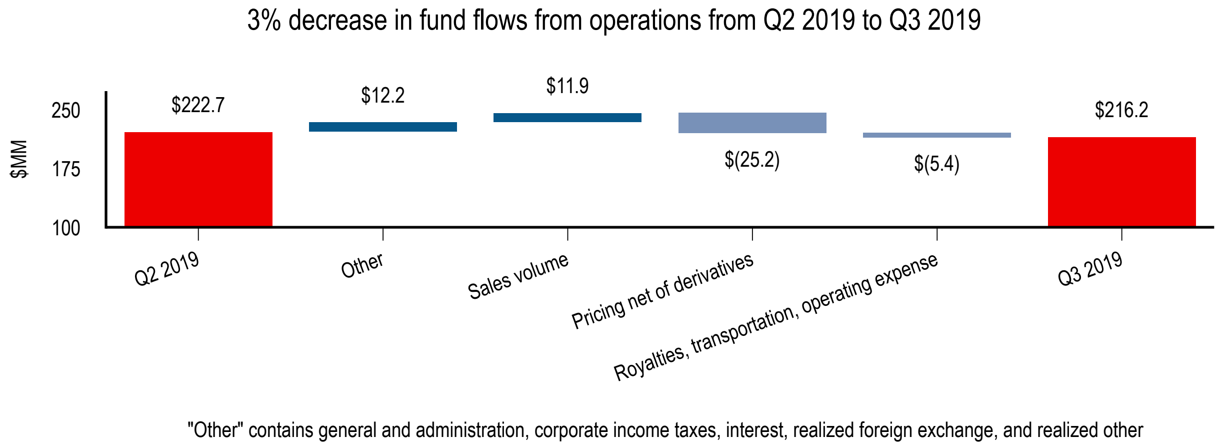
Q3 2019 vs. Q2 2019

Net loss of $10.2MM in Q3 2019 compared to net earnings of $2.0MM in Q2 2019



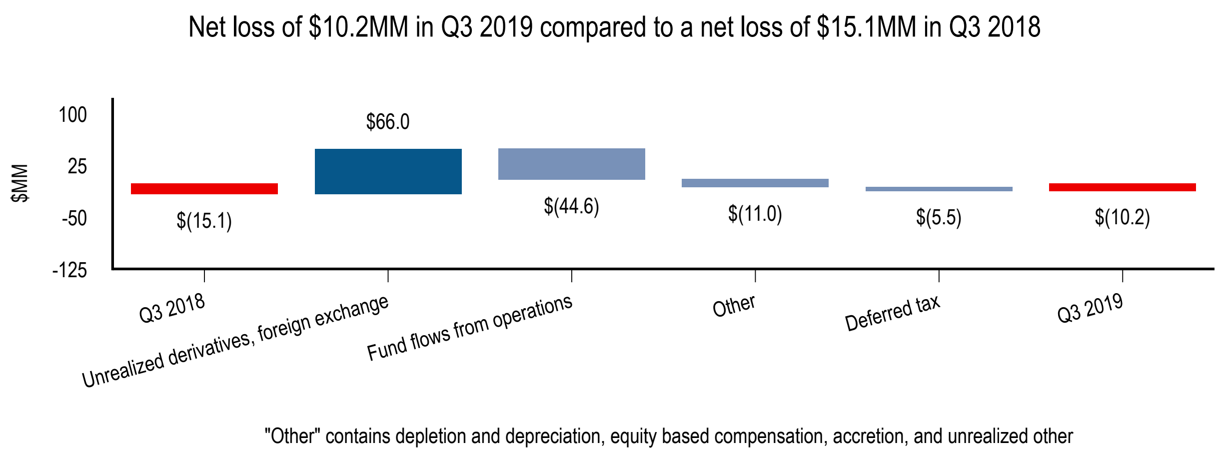
"Other" contains depletion and depreciation, equity based compensation, accretion, and unrealized other

- 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.



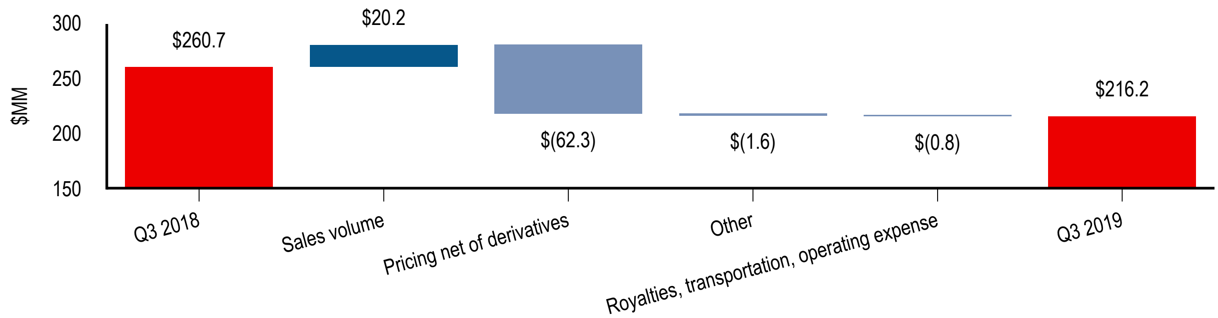
- We generated fund flows from operations of $216.2 million during Q3 2019, a slight decrease of 3% from Q2 2019 despite more significant decreases in commodity prices quarter-over-quarter, which included an 11% decrease in Dated Brent and a 23% decrease in TTF prices.
- We were able to mitigate a portion 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



- 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

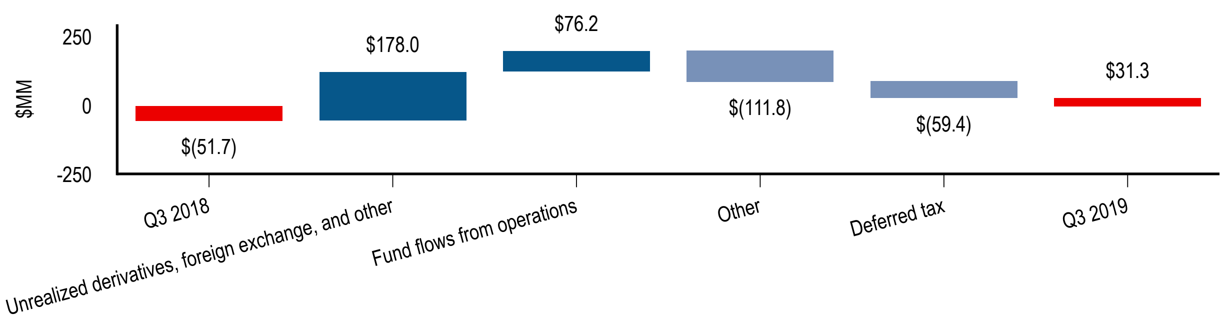


"Other" contains general and administration, corporate income taxes, interest, realized FX, and realized other

- 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

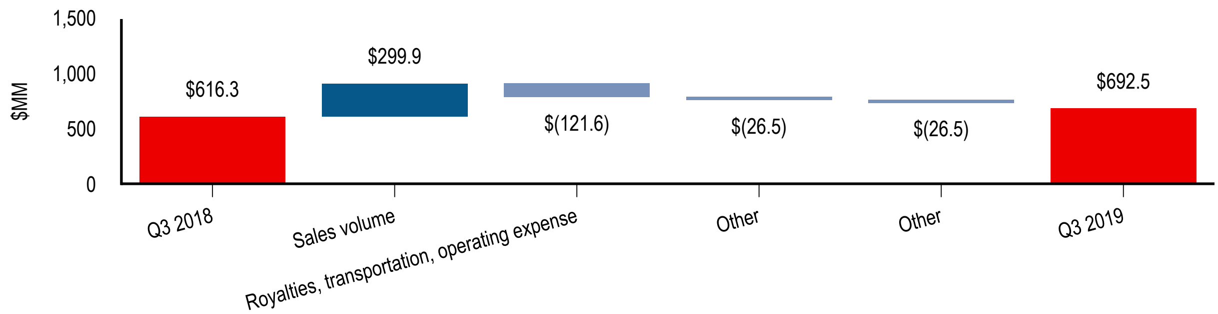
Net earning $31.3MM in YTD 2019 compared to net loss of $51.7MM in YTD 2018



"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

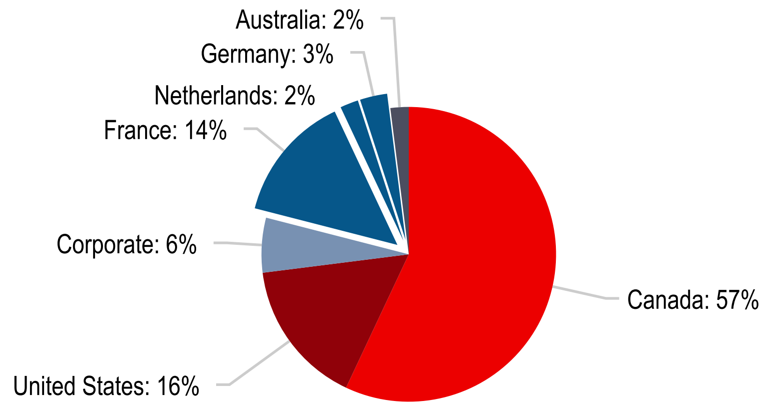
- Consolidated average production of 97,239 boe/d in Q3 2019 represented an increase of 1% from Q3 2018 due to growth in the United States, Canada, and Australia. In the United States, production growth resulted from an acquisition in Q3 2018 and organic drilling activity, including bringing on production 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

Q3 2019 capital expenditures of $127.9MM by business unit



- 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.

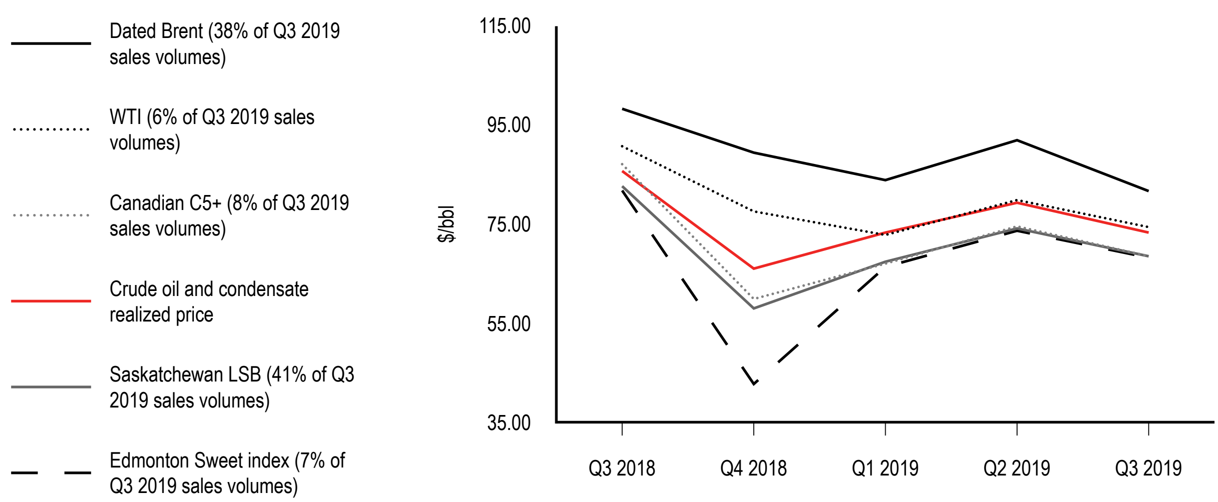
Long-term debt and net debt

- 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)%

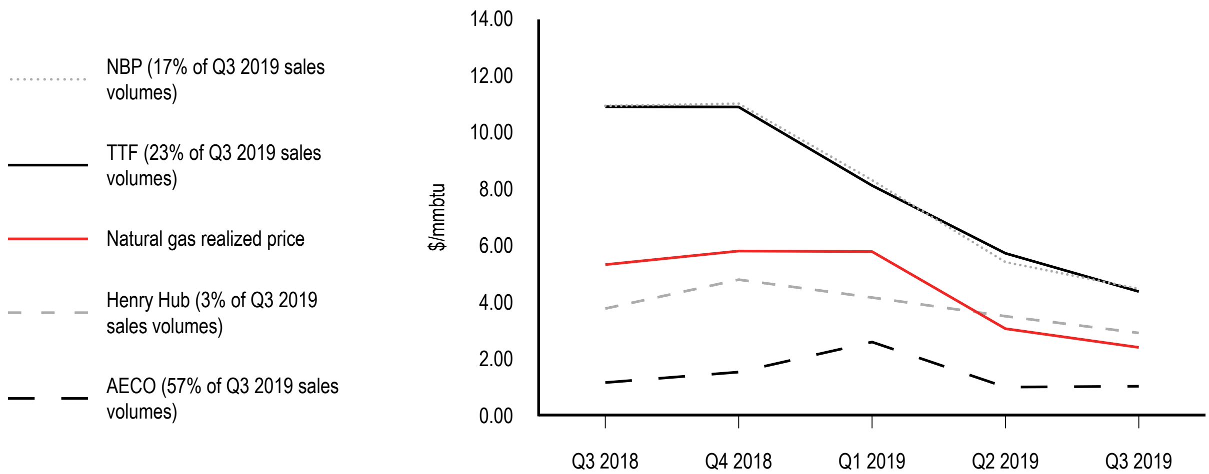
Q3 2019 realized crude oil and condensate price was a 7% premium to Edmonton Sweet Index



- 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.

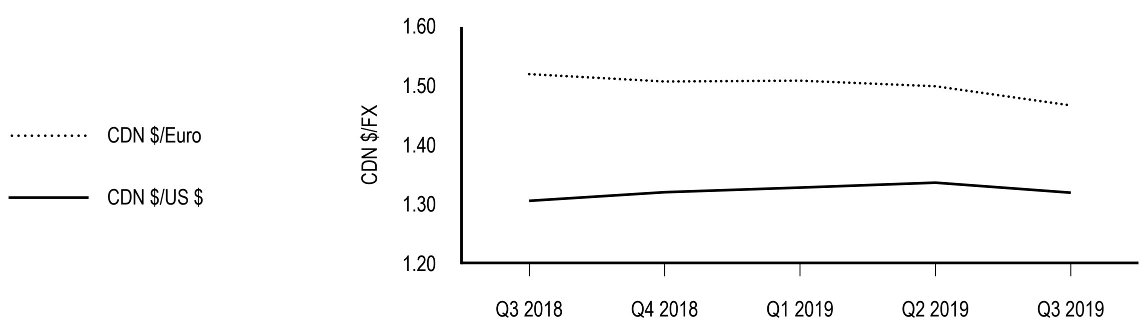
- In Canadian dollar terms, quarter-over-quarter, the Edmonton Sweet differential narrowed by $0.02/bbl to a discount of $6.16/bbl against WTI, and the Saskatchewan LSB differential widened by $0.15/bbl to a discount of $5.87/bbl against WTI.
- Vermilion's crude oil production benefits from light oil 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 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 ($M except as indicated)	Q3 2019	Q2 2019	Q3 2018	Q3/19 vs. Q2/19	Q3/19 vs. Q3/18	YTD 2019	YTD 2018	2019 vs. 2018
Production								
Crude oil (bbls/d)	**10,347**	9,800	11,407	5.6%	(9.3)%	**10,493**	11,377	(7.8)%
Natural gas (mmcf/d)	**—**	—	—	—%	—%	**0.25**	—	—%
Total (boe/d)	**10,347**	9,800	11,407	5.6%	(9.3)%	**10,535**	11,377	(7.4)%
Sales								
Crude oil (bbls/d)	**11,112**	10,190	11,482	9.0%	(3.2)%	**10,852**	11,025	(1.6)%
Natural gas (mmcf/d)	**—**	—	—	—%	—%	**0.25**	—	—%
Total (boe/d)	**11,112**	10,190	11,482	9.0%	(3.2)%	**10,894**	11,025	(1.2)%
Inventory (mbbls)								
Opening crude oil inventory	**297**	332	300			**325**	197	
Crude oil production	**952**	892	1,049			**2,865**	3,106	
Crude oil sales	**(1,022)**	(927)	(1,056)			**(2,963)**	(3,010)	
Closing crude oil inventory	**227**	297	293			**227**	293	
Activity								
Capital expenditures	**18,139**	25,671	15,779	(29.3)%	15.0%	**65,896**	62,750	5.0%
Gross wells drilled	**—**	1.00	—			**4.00**	5.00	
Net wells drilled	**—**	1.00	—			**4.00**	5.00	
Financial results								
Sales	**81,676**	84,540	100,840	(3.4)%	(19.0)%	**248,918**	274,713	(9.4)%
Royalties	**(11,476)**	(10,871)	(12,765)	5.6%	(10.1)%	**(33,630)**	(34,805)	(3.4)%
Transportation	**(6,183)**	(9,041)	(2,013)	(31.6)%	207.2%	**(18,394)**	(7,184)	156.0%
Operating	**(15,098)**	(14,305)	(13,733)	5.5%	9.9%	**(45,139)**	(40,675)	11.0%
General and administration	**(3,379)**	(3,551)	(3,365)	(4.8)%	0.4%	**(10,585)**	(10,378)	2.0%
Current income taxes	**(3,419)**	(5,346)	(6,913)	(36.0)%	(50.5)%	**(16,465)**	(14,200)	16.0%
Fund flows from operations	**42,121**	41,426	62,051	1.7%	(32.1)%	**124,705**	167,471	(25.5)%
Netbacks ($/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:

	As at	
($M)	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:

	As at	
($M)	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:

	As at	
($M)	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:

		As at	
Financial covenant	Limit	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 Liquids $/bbl	Q3 2019 Natural Gas $/mcf	Q3 2019 Total $/boe	YTD 2019 Liquids $/bbl	YTD 2019 Natural Gas $/mcf	YTD 2019 Total $/boe	Q3 2018 Total $/boe	YTD 2018 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:

	Twelve Months Ended	
($M)	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%**	—%

Consolidated Interim Financial Statements

Consolidated Balance Sheet

thousands of Canadian dollars, unaudited

	Note	September 30, 2019	December 31, 2018
Assets			
Current			
Cash and cash equivalents		**10,227**	26,809
Accounts receivable		**246,522**	260,322
Crude oil inventory		**16,150**	27,751
Derivative instruments		**46,387**	95,667
Prepaid expenses		**28,387**	19,328
Total current assets		**347,673**	429,877
Derivative instruments		**21,720**	1,215
Deferred taxes		**199,925**	219,411
Exploration and evaluation assets	6	**312,946**	303,295
Capital assets	5	**5,076,872**	5,316,873
Total assets		**5,959,136**	6,270,671
Liabilities			
Current			
Accounts payable and accrued liabilities		**310,560**	449,651
Dividends payable	9	**35,766**	35,122
Derivative instruments		**16,049**	41,016
Income taxes payable		**32,697**	37,410
Total current liabilities		**395,072**	563,199
Derivative instruments		**26,423**	17,527
Long-term debt	8	**1,954,471**	1,796,207
Lease obligations		**98,288**	108,189
Asset retirement obligations	7	**633,513**	650,164
Deferred taxes		**317,305**	318,134
Total liabilities		**3,425,072**	3,453,420
Shareholders' equity			
Shareholders' capital	9	**4,100,741**	4,008,828
Contributed surplus		**72,289**	78,478
Accumulated other comprehensive income		**45,545**	118,182
Deficit		**(1,684,511)**	(1,388,237)
Total shareholders' equity		**2,534,064**	2,817,251
Total liabilities and shareholders' equity		**5,959,136**	6,270,671

Approved by the Board

(Signed "Catherine L. Williams")

Catherine L. Williams, Director

(Signed "Anthony Marino")

Anthony Marino, Director

Consolidated Statements of Net (Loss) Earnings and Comprehensive Loss

thousands of Canadian dollars, except share and per share amounts, unaudited

		Three Months Ended		Nine Months Ended	
	Note	Sep 30, 2019	Sep 30, 2018	Sep 30, 2019	Sep 30, 2018
Revenue					
Petroleum and natural gas sales		**391,935**	508,411	**1,301,061**	1,221,178
Royalties		**(41,490)**	(53,786)	**(122,987)**	(108,293)
Sales of purchased commodities		**41,449**	—	**146,323**	—
Petroleum and natural gas revenue		**391,894**	454,625	**1,324,397**	1,112,885
Expenses					
Purchased commodities		**41,449**	—	**146,323**	—
Operating		**105,192**	97,758	**329,495**	244,544
Transportation		**19,426**	13,721	**56,876**	34,949
Equity based compensation		**15,564**	13,056	**53,000**	43,767
(Gain) loss on derivative instruments		**(54,785)**	113,194	**(34,442)**	246,709
Interest expense		**19,661**	19,772	**62,208**	51,932
General and administration		**13,652**	13,234	**42,407**	39,115
Foreign exchange loss (gain)		**54,027**	26,144	**(7,410)**	32,528
Other (income) expense		**(25)**	26	**(6,826)**	(11)
Accretion	7	**8,701**	8,041	**24,834**	23,014
Depletion and depreciation	5, 6	**174,077**	166,343	**535,237**	434,621
		396,939	471,289	**1,201,702**	1,151,168
(Loss) earnings before income taxes		**(5,045)**	(16,664)	**122,695**	(38,283)
Taxes					
Deferred		**(5,169)**	(10,712)	**34,761**	(24,613)
Current		**10,353**	9,147	**56,612**	38,053
		5,184	(1,565)	**91,373**	13,440
Net (loss) earnings		**(10,229)**	(15,099)	**31,322**	(51,723)
Other comprehensive loss					
Currency translation adjustments		**(24,388)**	(20,592)	**(83,993)**	(4,983)
Unrealized gains on derivatives designated as cash flow hedges	8	**3,373**	—	**4,749**	—
Unrealized gains on derivatives designated as net investment hedges	8	**6,815**	—	**6,607**	—
Comprehensive loss		**(24,429)**	(35,691)	**(41,315)**	(56,706)
Net (loss) earnings per share					
Basic		**(0.07)**	(0.10)	**0.20**	(0.38)
Diluted		**(0.07)**	(0.10)	**0.20**	(0.38)
Weighted average shares outstanding ('000s)					
Basic		**155,254**	152,432	**154,326**	136,585
Diluted		**155,254**	152,432	**155,673**	136,585

Consolidated Statements of Cash Flows

thousands of Canadian dollars, unaudited

	Note	Three Months Ended Sep 30, 2019	Three Months Ended Sep 30, 2018	Nine Months Ended Sep 30, 2019	Nine Months Ended Sep 30, 2018
Operating					
Net (loss) earnings		**(10,229)**	(15,099)	**31,322**	(51,723)
Adjustments:					
Accretion	7	**8,701**	8,041	**24,834**	23,014
Depletion and depreciation	5, 6	**174,077**	166,343	**535,237**	434,621
Unrealized (gain) loss on derivative instruments		**(17,817)**	75,829	**27,065**	163,770
Equity based compensation		**15,564**	13,056	**53,000**	43,767
Unrealized foreign exchange loss (gain)		**50,679**	23,044	**(14,377)**	26,877
Unrealized other expense		**347**	203	**621**	597
Deferred taxes		**(5,169)**	(10,712)	**34,761**	(24,613)
Asset retirement obligations settled	7	**(3,586)**	(2,986)	**(12,090)**	(9,203)
Changes in non-cash operating working capital		**16,034**	52,325	**(77,454)**	29,570
Cash flows from operating activities		**228,601**	310,044	**602,919**	636,677
Investing					
Drilling and development	5	**(117,123)**	(142,116)	**(389,563)**	(343,483)
Exploration and evaluation	6	**(10,756)**	(4,069)	**(32,976)**	(11,151)
Acquisitions	5	**(4,657)**	(193,677)	**(29,307)**	(307,622)
Changes in non-cash investing working capital		**(31,476)**	8,122	**(49,846)**	9,158
Cash flows used in investing activities		**(164,012)**	(331,740)	**(501,692)**	(653,098)
Financing					
Borrowings on the revolving credit facility	8	**17,533**	113,895	**196,944**	237,061
Payments on lease obligations		**(9,337)**	(5,441)	**(20,525)**	(13,679)
Cash dividends		**(98,207)**	(100,841)	**(294,228)**	(230,047)
Cash flows (used in) from financing activities		**(90,011)**	7,613	**(117,809)**	(6,665)
Foreign exchange gain (loss) on cash held in foreign currencies		**585**	(1,027)	**—**	519
Net change in cash and cash equivalents		**(24,837)**	(15,110)	**(16,582)**	(22,567)
Cash and cash equivalents, beginning of period		**35,064**	39,104	**26,809**	46,561
Cash and cash equivalents, end of period		**10,227**	23,994	**10,227**	23,994
Supplementary information for cash flows from operating activities					
Interest paid		**25,455**	24,914	**68,410**	56,084
Income taxes paid		**14,753**	1,505	**61,325**	35,631

Consolidated Statements of Changes in Shareholders' Equity

thousands of Canadian dollars, unaudited

	Note	Nine Months Ended September 30, 2019	September 30, 2018
Shareholders' capital	9		
Balance, beginning of period		**4,008,828**	2,650,706
Shares issued for acquisition		**—**	1,234,676
Shares issued for the Dividend Reinvestment Plan		**24,737**	43,936
Vesting of equity based awards		**45,636**	54,057
Equity based compensation		**13,553**	10,626
Share-settled dividends on vested equity based awards		**7,987**	7,773
Balance, end of period		**4,100,741**	4,001,774
Contributed surplus			
Balance, beginning of period		**78,478**	84,354
Equity based compensation		**39,447**	33,141
Vesting of equity based awards		**(45,636)**	(54,057)
Balance, end of period		**72,289**	63,438
Accumulated other comprehensive income			
Balance, beginning of period		**118,182**	71,829
Currency translation adjustments		**(83,993)**	(4,983)
Gains on derivatives designated as cash flow hedges	8	**5,685**	—
Amount reclassified from cash flow hedge reserve to net (loss) earnings		**(936)**	—
Gains on derivatives designated as net investment hedges	8	**4,102**	—
Amount reclassified from net investment hedge reserve to net (loss) earnings		**2,505**	—
Balance, end of period		**45,545**	66,846
Deficit			
Balance, beginning of period		**(1,388,237)**	(1,264,003)
Net loss (earnings)		**31,322**	(51,723)
Dividends declared	9	**(319,609)**	(282,801)
Share-settled dividends on vested equity based awards		**(7,987)**	(7,773)
Balance, end of period		**(1,684,511)**	(1,606,300)
Total shareholders' equity		**2,534,064**	2,525,758

Notes to the Condensed Consolidated Interim Financial Statements for the three and nine months ended September 30, 2019 and 2018

tabular amounts in thousands of Canadian dollars, except share and per share amounts, unaudited

1. Basis of presentation

Vermilion Energy Inc. (the "Company" or "Vermilion") is a corporation governed by the laws of the Province of Alberta and is actively engaged in the business of crude oil and natural gas exploration, development, acquisition and production.

These condensed consolidated interim financial statements are in compliance with International Accounting Standard ("IAS") 34, "Interim Financial Reporting". Except as described in Notes 2 and 3, these condensed consolidated interim financial statements have been prepared using the same accounting policies and methods of computation as Vermilion's consolidated financial statements for the year ended December 31, 2018.

These condensed consolidated interim financial statements should be read in conjunction with Vermilion's consolidated financial statements for the year ended December 31, 2018, which are contained within Vermilion's Annual Report for the year ended December 31, 2018 and are available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

These condensed consolidated interim financial statements were approved and authorized for issuance by the Board of Directors of Vermilion on October 30, 2019.

2. Significant accounting policies

On June 12, 2019, Vermilion entered into a series of cross currency interest rate swaps with a syndicate of banks. The details of these derivative instruments are disclosed in Note 8 (Long-term debt). Vermilion designated these derivative instruments as hedging instruments in qualifying hedging relationships. As such, effective June 12, 2019, Vermilion has adopted the following policies relating to hedge accounting.

Hedge Accounting

Hedge accounting is applied to financial instruments designated as hedging instruments in qualifying hedging relationships. Qualifying hedge relationships may include cash flow hedges, fair value hedges, and hedges of net investments in foreign operations. The purpose of hedge accounting is to represent the effect of Vermilion's risk management activities that use financial instruments to manage exposures arising from specific risks that affect net earnings.

In order to apply hedge accounting, the eligible hedging instrument must be highly effective in offsetting the exposure to changes in the eligible hedged item. This effectiveness is assessed at inception and at the end of each reporting period thereafter. At the inception of the hedge, formal designation and documentation is required of the hedging relationship and Vermilion's risk management objective and strategy for undertaking the hedge.

For cash flow hedges and net investment hedges, gains and losses on the hedging instrument are recognized in the consolidated statement of earnings in the same period in which the transaction associated with the hedged item occurs. Where the hedging instrument is a derivative instrument, a derivative asset or liability is recognized on the balance sheet at fair value (included in "Derivative instruments") with the effective portion of the gain or loss recorded to other comprehensive income. Any gain or loss associated with the ineffective portion of a hedging relationship, which is expected to be immaterial, is immediately recognized in the consolidated statement of net earnings as other income or expense.

If a hedging relationship no longer qualifies for hedge accounting, any gain or loss resulting from the discontinuation of hedge accounting is deferred in other comprehensive income until the forecasted transaction date. If the forecasted transaction is no longer expected to occur, any gain or loss resulting from the discontinuation of hedge accounting is immediately recognized in the consolidated statement of net earnings.

3. Changes in 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.

4. Segmented information

	Three Months Ended September 30, 2019								
	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Drilling and development	69,963	18,017	2,730	2,023	354	2,995	21,064	(23)	117,123
Exploration and evaluation	—	122	298	2,206	—	—	—	8,130	10,756
Crude oil and condensate sales	169,237	81,676	523	6,080	12	56,188	17,254	—	330,970
NGL sales	3,401	—	—	—	—	—	990	—	4,391
Natural gas sales	15,435	—	18,206	5,240	16,710	—	983	—	56,574
Sales of purchased commodities	—	—	—	—	—	—	—	41,449	41,449
Royalties	(23,909)	(11,476)	(279)	(952)	—	—	(4,874)	—	(41,490)
Revenue from external customers	164,164	70,200	18,450	10,368	16,722	56,188	14,353	41,449	391,894
Purchased commodities	—	—	—	—	—	—	—	(41,449)	(41,449)
Transportation	(10,404)	(6,183)	—	(1,709)	(1,130)	—	—	—	(19,426)
Operating	(57,851)	(15,098)	(6,396)	(6,433)	(3,136)	(11,876)	(4,400)	(2)	(105,192)
General and administration	(5,793)	(3,379)	(300)	(2,436)	(1,436)	(1,260)	(2,005)	2,957	(13,652)
PRRT	—	—	—	—	—	(5,826)	—	—	(5,826)
Corporate income taxes	—	(3,419)	(462)	—	—	(396)	—	(250)	(4,527)
Interest expense	—	—	—	—	—	—	—	(19,661)	(19,661)
Realized gain on derivative instruments	—	—	—	—	—	—	—	36,968	36,968
Realized foreign exchange loss	—	—	—	—	—	—	—	(3,348)	(3,348)
Realized other income	—	—	—	—	—	—	—	372	372
Fund flows from operations	**90,116**	**42,121**	**11,292**	**(210)**	**11,020**	**36,830**	**7,948**	**17,036**	**216,153**

	Three Months Ended September 30, 2018								
	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Drilling and development	89,837	15,682	5,148	4,271	(50)	16,061	11,386	(219)	142,116
Exploration and evaluation	—	97	(92)	2,226	—	—	—	1,838	4,069
Crude oil and condensate sales	209,219	100,840	634	7,898	—	35,848	11,740	—	366,179
NGL sales	15,680	—	—	—	—	—	1,919	—	17,599
Natural gas sales	18,117	—	41,159	13,154	50,228	—	892	1,083	124,633
Royalties	(33,801)	(12,765)	(1,049)	(2,448)	—	—	(3,444)	(279)	(53,786)
Revenue from external customers	209,215	88,075	40,744	18,604	50,228	35,848	11,107	804	454,625
Transportation	(9,057)	(2,013)	—	(1,191)	(1,460)	—	—	—	(13,721)
Operating	(55,577)	(13,733)	(5,812)	(4,863)	(3,354)	(11,585)	(2,633)	(201)	(97,758)
General and administration	(1,316)	(3,365)	(320)	(2,073)	(3,597)	(1,020)	(2,397)	854	(13,234)
PRRT	—	—	—	—	—	254	—	—	254
Corporate income taxes	—	(6,913)	1,729	—	—	(3,355)	—	(862)	(9,401)
Interest expense	—	—	—	—	—	—	—	(19,772)	(19,772)
Realized loss on derivative instruments	—	—	—	—	—	—	—	(37,365)	(37,365)
Realized foreign exchange loss	—	—	—	—	—	—	—	(3,100)	(3,100)
Realized other income	—	—	—	—	—	—	—	177	177
Fund flows from operations	**143,265**	**62,051**	**36,341**	**10,477**	**41,817**	**20,142**	**6,077**	**(59,465)**	**260,705**

	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
				Nine Months Ended September 30, 2019					
Total assets	3,096,572	847,956	226,687	268,862	554,724	220,312	428,774	315,249	5,959,136
Drilling and development	227,101	65,772	13,295	4,451	449	24,098	54,064	333	389,563
Exploration and evaluation	—	124	659	12,056	—	—	—	20,137	32,976
Crude oil and condensate sales	532,245	248,797	1,803	21,292	16	162,618	44,068	—	1,010,839
NGL sales	24,375	—	—	—	—	—	4,299	—	28,674
Natural gas sales	64,553	121	85,839	24,489	82,434	—	4,112	—	261,548
Sales of purchased commodities	—	—	—	—	—	—	—	146,323	146,323
Royalties	(69,951)	(33,630)	(1,339)	(4,677)	—	—	(13,390)	—	(122,987)
Revenue from external customers	551,222	215,288	86,303	41,104	82,450	162,618	39,089	146,323	1,324,397
Purchased commodities	—	—	—	—	—	—	—	(146,323)	(146,323)
Transportation	(30,877)	(18,394)	—	(4,154)	(3,451)	—	—	—	(56,876)
Operating	(181,859)	(45,139)	(22,367)	(17,565)	(9,577)	(41,372)	(11,374)	(242)	(329,495)
General and administration	(15,917)	(10,585)	(1,896)	(6,495)	(2,007)	(3,463)	(5,467)	3,423	(42,407)
PRRT	—	—	—	—	—	(24,494)	—	—	(24,494)
Corporate income taxes	—	(16,465)	(7,237)	—	—	(7,912)	—	(504)	(32,118)
Interest expense	—	—	—	—	—	—	—	(62,208)	(62,208)
Realized gain on derivative instruments	—	—	—	—	—	—	—	61,507	61,507
Realized foreign exchange loss	—	—	—	—	—	—	—	(6,967)	(6,967)
Realized other income	—	—	—	—	—	—	—	7,447	7,447
Fund flows from operations	**322,569**	**124,705**	**54,803**	**12,890**	**67,415**	**85,377**	**22,248**	**2,456**	**692,463**

	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
				Nine Months Ended September 30, 2018					
Total assets	3,107,386	864,425	199,212	284,368	575,195	227,055	327,353	333,636	5,918,630
Drilling and development	187,646	62,581	15,671	7,776	84	31,878	37,956	(109)	343,483
Exploration and evaluation	—	169	(642)	3,450	—	—	—	8,174	11,151
Crude oil and condensate sales	394,897	274,713	1,741	25,962	—	111,382	20,690	—	829,385
NGL sales	40,544	—	—	—	—	—	2,160	—	42,704
Natural gas sales	49,423	—	111,238	34,590	151,765	—	990	1,083	349,089
Royalties	(59,112)	(34,805)	(2,644)	(5,436)	—	—	(6,017)	(279)	(108,293)
Revenue from external customers	425,752	239,908	110,335	55,116	151,765	111,382	17,823	804	1,112,885
Transportation	(18,783)	(7,184)	—	(4,968)	(4,014)	—	—	—	(34,949)
Operating	(115,435)	(40,675)	(19,916)	(16,433)	(10,869)	(37,442)	(3,573)	(201)	(244,544)
General and administration	(3,907)	(10,378)	(1,238)	(5,093)	(6,349)	(3,527)	(4,910)	(3,713)	(39,115)
PRRT	—	—	—	—	—	(7,246)	—	—	(7,246)
Corporate income taxes	—	(14,200)	(9,069)	—	—	(6,379)	—	(1,159)	(30,807)
Interest expense	—	—	—	—	—	—	—	(51,932)	(51,932)
Realized loss on derivative instruments	—	—	—	—	—	—	—	(82,939)	(82,939)
Realized foreign exchange loss	—	—	—	—	—	—	—	(5,651)	(5,651)
Realized other income	—	—	—	—	—	—	—	608	608
Fund flows from operations	**287,627**	**167,471**	**80,112**	**28,622**	**130,533**	**56,788**	**9,340**	**(144,183)**	**616,310**

Reconciliation of fund flows from operations to net earnings:

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

5. Capital assets

The following table reconciles the change in Vermilion's capital assets:

	2019
Balance at January 1	**5,316,873**
Acquisitions	**29,307**
Additions	**389,563**
Increase in right-of-use assets	**12,201**
Transfers from exploration and evaluation assets	**1,039**
Depletion and depreciation	**(518,354)**
Changes in asset retirement obligations	**10,743**
Foreign exchange	**(164,500)**
Balance at September 30	**5,076,872**

Q3 2019 impairment assessment

On a quarterly basis, Vermilion performs an assessment as to whether any cash generating units ("CGUs") have indicators of impairment. When indicators of impairment are identified, Vermilion assesses the recoverable amount of the applicable CGU based on the higher of the estimated fair value less costs to sell and value in use as at the reporting date. The estimated recoverable amount takes into account commodity price forecasts, expected production, estimated costs and timing of development, and undeveloped land values.

Due to a decrease in the European natural gas price forecast issued by GLJ and the resulting reduction in forecast revenues in our Ireland segment, Vermilion estimated the recoverable amount of our Ireland CGU. The recoverable amount, based on fair value less costs of disposal, was estimated using a 9% after-tax discount rate derived from proved plus probable reserve estimates.

The following commodity price estimates, as issued by GLJ Petroleum Consultants effective October 1, 2019, were applied:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
NBP (€/mmbtu)	5.80	5.95	6.09	6.30	6.52	6.74	6.74	6.74	6.74	6.87

Based on the above assumptions, the estimated recoverable amount exceeded the carrying value of our Ireland CGU. As such, no impairment was recorded in the three and nine months ended September 30, 2019.

Changes in any of the key judgments, such as a revision in reserves, changes in forecast commodity prices, foreign exchange rates, capital or operating costs would impact the estimated recoverable amount. As at September 30, 2019, a 1% increase in the assumed after-tax discount rate would reduce the estimated recoverable amount by $17.4 million (resulting in a $0.1 million impairment) while a 5% decrease in revenues (due to a decrease in commodity price forecasts or reserve estimates) would reduce the estimated recoverable amount by $19.2 million (resulting in a $1.9 million impairment).

6. Exploration and evaluation assets

The following table reconciles the change in Vermilion's exploration and evaluation assets:

	2019
Balance at January 1	**303,295**
Additions	**32,976**
Changes in asset retirement obligations	**53**
Transfers to capital assets	**(1,039)**
Depreciation	**(13,967)**
Foreign exchange	**(8,372)**
Balance at September 30	**312,946**

7. Asset retirement obligations

The following table reconciles the change in Vermilion's asset retirement obligations:

	2019
Balance at January 1	**650,164**
Additional obligations recognized	**577**
Changes in estimated abandonment timing and costs	**(137)**
Obligations settled	**(12,090)**
Accretion	**24,834**
Changes in discount rates	**10,356**
Foreign exchange	**(40,191)**
Balance at September 30	**633,513**

8. Long-term debt

The following table summarizes Vermilion's outstanding long-term debt:

	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

The fair value of the revolving credit facility is equal to its carrying value due to the use of short-term borrowing instruments at market rates of interest. The fair value of the senior unsecured notes as at September 30, 2019 was $382.7 million.

The following table reconciles the change in Vermilion's long-term debt:

	2019
Balance at January 1	**1,796,207**
Borrowings on the revolving credit facility	**196,944**
Amortization of transaction costs and prepaid interest	**150**
Foreign exchange	**(38,830)**
Balance at September 30	**1,954,471**

Revolving credit facility

At September 30, 2019, Vermilion had in place a bank revolving credit facility maturing May 31, 2023 with the following terms:

	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

The facility can be extended from time to time at the option of the lenders and upon notice from Vermilion. If no extension is granted by the lenders, the amounts owing pursuant to the facility are due at the maturity date. The facility is secured by various fixed and floating charges against the subsidiaries of Vermilion.

The facility bears interest at a rate applicable to demand loans plus applicable margins.

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

		As at	
Financial covenant	Limit	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

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

- Consolidated total debt: Includes all amounts classified as “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 the 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.
- Consolidated total interest expense: Includes all amounts classified as "Interest expense", but excluding interest on operating leases as defined under IAS 17.

As at September 30, 2019 and 2018, Vermilion was in compliance with the above covenants.

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, to be paid semi-annually on March 15 and September 15. The notes mature on March 15, 2025. As direct senior unsecured obligations of Vermilion, the notes rank equally with existing and future senior unsecured indebtedness of the Company.

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

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

- Prior to 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 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 an applicable 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. Vermilion applied hedge accounting to these derivative instruments. 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:

- US dollar to Canadian dollar ("USD-to-CAD") cross currency interest rate swaps: 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.
- Canadian dollar to Euro ("CAD-to-EUR") cross currency interest rate swaps: Vermilion 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%.

The USD-to-CAD cross currency interest swaps have been designated as the hedging instrument in a cash flow hedge to mitigate the risk of the fluctuation of interest and principal cash flows due to changes in foreign currency rates related to the Senior Unsecured Notes described above. The forward element of the swap contract is treated as the excluded component and is initially recognized within other comprehensive income. The excluded component is amortized to net earnings in interest expense on a systematic basis. As the timing and amount of the cash flows received on the USD-to-CAD cross currency interest rate swaps offset the timing and amount of the cash flows paid on the senior unsecured notes, the economic relationship is expected to be highly effective. The change in the value of the hedged item associated with a change in spot foreign exchange rates is initially recognized in other comprehensive income. This change is reclassified from other comprehensive income to net earnings (and recorded as an foreign exchange gain or loss) to offset the associated foreign exchange gain or loss recognized on the senior unsecured notes.

The CAD-to-EUR cross currency interest rate swaps have been designated as the hedging instrument in a net investment hedge to mitigate the effective change in exchange rates on our net investments in Euro denominated foreign subsidiaries. The change in the value of the hedged item associated with a change in spot foreign exchange rates is initially recognized in other comprehensive income. This change is reclassified from other comprehensive income to net earnings (and recorded as a foreign exchange gain or loss) only if the net investment is disposed of by sale. The forward element of the swap contract is treated as the excluded component and is initially recognized within other comprehensive income. The excluded component is amortized to net earnings in interest expense on a systematic basis.

9. Shareholders' capital

The following table reconciles the change in Vermilion's shareholders' capital:

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

Dividends declared to shareholders for the nine months ended September 30, 2019 were $319.6 million (2018 - $282.8 million).

Subsequent to the end of the period and prior to the condensed consolidated interim financial statements being authorized for issue, Vermilion declared dividends of $35.8 million or $0.23 per share.

10. Capital disclosures

Vermilion defines capital as net debt (long-term debt plus net working capital) and shareholders' capital. In managing capital, Vermilion reviews whether fund flows from operations is sufficient to fund capital expenditures, dividends, and asset retirement obligations.

The following table calculates Vermilion's ratio of net debt to trailing twelve month fund flows from operations:

	Sep 30, 2019	Sep 30, 2018
Long-term debt	**1,954,471**	1,728,889
Current liabilities	**398,233**	629,893
Current assets	**(350,834)**	(324,696)
Net debt	**2,001,870**	2,034,086
Ratio of net debt to trailing twelve months fund flows from operations	**2.19**	2.55

11. Financial instruments

The following table summarizes the increase (positive values) or decrease (negative values) to net earnings before tax due to a change in the value of Vermilion's financial instruments as a result of a change in the relevant market risk variable. This analysis does not attempt to reflect any interdependencies between the relevant risk variables.

	Sep 30, 2019
Currency risk - Euro to Canadian dollar	
$0.01 increase in strength of the Canadian dollar against the Euro	**(2,008)**
$0.01 decrease in strength of the Canadian dollar against the Euro	**2,008**
Currency risk - US dollar to Canadian dollar	
$0.01 increase in strength of the Canadian dollar against the US $	**104**
$0.01 decrease in strength of the Canadian dollar against the US $	**(104)**
Commodity price risk - Crude oil	
US $5.00/bbl increase in crude oil price used to determine the fair value of derivatives	**(26,206)**
US $5.00/bbl decrease in crude oil price used to determine the fair value of derivatives	**36,814**
Commodity price risk - European natural gas	
€0.5/GJ increase in European natural gas price used to determine the fair value of derivatives	**(27,826)**
€0.5/GJ decrease in European natural gas price used to determine the fair value of derivatives	**32,167**

DIRECTORS

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Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Carin Knickel [6, 8, 12]
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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

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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
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Terry Hergott
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Kyle Preston
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Jenson Tan
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Jeremy Kalanuk
Director Operations Accounting

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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

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Managing Director - U.S. Business Unit

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EUROPE
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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

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Calgary, Alberta

BANKERS

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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

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La Caisse Centrale Desjardins du Québec

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EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

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