Q1 2019

FIRST 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", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this document may include, but are not limited to: capital expenditures; business strategies and objectives; operational and financial performance; estimated reserve quantities and the discounted net present value of future net revenue from such reserves; petroleum and natural gas sales; future production levels (including the timing thereof) and rates of average annual production growth; exploration and development plans; acquisition and disposition plans and the timing thereof; operating and other expenses, including the payment and amount of future dividends; royalty and income tax rates; and the timing of regulatory proceedings and approvals.

Such forward looking statements or information are based on a number of assumptions, all or any of which may prove to be incorrect. In addition to any other assumptions identified in this document, assumptions have been made regarding, among other things: the ability of Vermilion to obtain equipment, services and supplies in a timely manner to carry out its activities in Canada and internationally; the ability of Vermilion to market crude oil, natural gas liquids, and natural gas successfully to current and new customers; the timing and costs of pipeline and storage facility construction and expansion and the ability to secure adequate product transportation; the timely receipt of required regulatory approvals; the ability of Vermilion to obtain financing on acceptable terms; foreign currency exchange rates and interest rates; future crude oil, natural gas liquids, and natural gas prices; and management's expectations relating to the timing and results of exploration and development activities.

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

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

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

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

Abbreviations

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

Highlights

- Q1 2019 production averaged 103,404 boe/d, representing a 2% increase over the prior quarter, due to increases in Australia, Canada, the US, Germany and France.

- Fund flows from operations ("FFO") for Q1 2019 was $254 million ($1.66/basic share(1)), an increase of 14% from the previous quarter (14% on a per share basis) as a result of higher production and realized commodity pricing, partially offset by higher cash taxes. FFO for Q1 2019 increased 58% (27% on a per share basis) compared to the same quarter last year due to higher production, which was partially offset by lower commodity pricing and higher cash taxes.

- In Australia, production averaged 5,862 bbl/d in Q1 2019, an increase of 40% from the previous quarter primarily due to the contribution from the two (2.0 net) well program completed at the end of January 2019.

- In Canada, production averaged 61,360 boe/d in Q1 2019, an increase of 1% from the prior quarter, primarily driven by new well completions.

- In the United States, Q1 2019 production averaged 3,653 boe/d, an increase of 3% from the prior quarter, primarily driven by a full quarter contribution from our first Hilight well drilled in the prior quarter.

- In Germany, production in Q1 2019 averaged 3,763 boe/d, an increase of 1% from the prior quarter. The increase is primarily due to better than expected results from workovers performed on our operated oil assets. Late in the quarter, we commenced drilling of the Burgmoor Z5 well (46% working interest), marking the first operated drilling program by Vermilion in Germany.

- In the Netherlands, Q1 2019 production averaged 8,677 boe/d, a 1% decrease from the prior quarter. We continue to make progress on the permitting for our two (1.0 net) 2019 planned wells. We received the drilling permit for one well during the first quarter, and are currently awaiting regulatory decisions on two additional wells, which should enable us to execute our planned program for this year.

- In Ireland, production averaged approximately 52 mmcf/d (8,619 boe/d) in Q1 2019, a decrease of 1% from the prior quarter. In our first full quarter as operator of the Corrib Project, we completed some minor projects and activities previously identified to increase uptime and optimize plant compression to increase gas throughput. We will continue to evaluate other optimization opportunities throughout 2019 as we build more first-hand knowledge as operator.

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

($M except as indicated)	Q1 2019	Q4 2018	Q1 2018
Financial			
Petroleum and natural gas sales	**481,083**	456,939	318,269
Fund flows from operations	**253,572**	222,342	160,415
Fund flows from operations ($/basic share) (1)	**1.66**	1.45	1.31
Fund flows from operations ($/diluted share) (1)	**1.64**	1.44	1.29
Net earnings (loss)	**39,547**	323,373	24,740
Net earnings (loss) ($/basic share)	**0.26**	2.12	0.20
Capital expenditures	**202,053**	163,580	128,465
Acquisitions	**16,027**	2,689	93,078
Asset retirement obligations settled	**3,597**	6,562	3,591
Cash dividends ($/share)	**0.690**	0.690	0.645
Dividends declared	**105,549**	105,310	79,005
% of fund flows from operations	**42%**	47%	49%
Net dividends (1)	**98,445**	100,195	59,364
% of fund flows from operations	**39%**	45%	37%
Payout (1)	**304,095**	270,337	191,420
% of fund flows from operations	**120%**	122%	119%
Net debt	**2,000,144**	1,929,529	1,525,562
Ratio of net debt to annualized fund flows from operations	**1.97**	2.17	2.38
Operational			
Production			
Crude oil and condensate (bbls/d)	**49,181**	47,678	27,008
NGLs (bbls/d)	**7,897**	7,815	5,126
Natural gas (mmcf/d)	**277.96**	276.77	228.20
Total (boe/d)	**103,404**	101,621	70,167
Average realized prices			
Crude oil and condensate ($/bbl)	**73.45**	66.19	80.03
NGLs ($/bbl)	**22.49**	25.69	25.37
Natural gas ($/mcf)	**5.10**	5.83	5.81
Production mix (% of production)			
% priced with reference to WTI	**37%**	37%	21%
% priced with reference to Dated Brent	**18%**	18%	24%
% priced with reference to AECO	**26%**	26%	26%
% priced with reference to TTF and NBP	**19%**	19%	29%
Netbacks ($/boe)			
Operating netback (1)	**31.50**	27.58	31.27
Fund flows from operations netback	**26.76**	23.79	25.77
Operating expenses	**12.92**	12.04	10.90
General and administration expenses	**1.38**	1.37	1.88
Average reference prices			
WTI (US $/bbl)	**54.90**	58.81	62.87
Edmonton Sweet index (US $/bbl)	**50.05**	32.51	56.98
Saskatchewan LSB index (US $/bbl)	**50.84**	44.03	56.63
Dated Brent (US $/bbl)	**63.20**	67.76	66.76
AECO ($/mcf)	**2.62**	1.56	2.08
NBP ($/mcf)	**8.33**	11.03	9.96
TTF ($/mcf)	**8.14**	10.91	9.59
Average foreign currency exchange rates			
CDN $/US $	**1.33**	1.32	1.26
CDN $/Euro	**1.51**	1.51	1.55
Share information ('000s)			
Shares outstanding - basic	**153,213**	152,704	122,769
Shares outstanding - diluted (1)	**156,650**	156,173	125,794
Weighted average shares outstanding - basic	**152,904**	152,588	122,390
Weighted average shares outstanding - diluted (1)	**154,550**	153,880	124,304

(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

We delivered strong operational and financial results in Q1 2019. Production increased 2% quarter-over-quarter to 103,404 boe/d and FFO increased 14% from the prior quarter to $254 million. While global benchmark commodity prices were weaker in Q1 2019 compared to the prior quarter, we benefited from a significant improvement in Canadian benchmark prices and continued positive operational momentum across our asset base. On a per share basis we generated $1.66[1] of FFO in Q1 2019 compared to $1.31 in Q1 2018, representing a year-over-year increase of 27% despite most commodity benchmark prices being lower over this comparative period, reflecting accretion from the acquisitions we completed in 2018 and our ongoing organic development activities. Our Australian and Canadian business units were responsible for most of the growth in Q1 2019 as we brought two new offshore wells on production in Australia and executed one of our most active drilling programs to date in Canada. We achieved increased production despite an unusually active cyclone season in Australia, which resulted in 11 days of downtime at Wandoo and extremely cold weather conditions in our producing areas in Canada and the US.

We are committed to our capital markets strategy of sustainable growth and income. With all business units contributing strong development results to-date and most completion and tie-in activities in North America completed at break-up, we expect to deliver robust year-over-year production per share growth in 2019 of 8% or more, while paying a sustainable dividend which is currently yielding approximately 8%. We typically have a front-loaded capital program which seeks to finish as much Canadian drilling and tie-in activity ahead of break-up as possible, and this year was no exception, with nearly 40% of our annual capital investment for Exploration and Development ("E&D") activities executed in Q1 2019. As a result, our total payout ratio exceeded 100% for the quarter. However, based on the current commodity strip, our annual capital program and dividend are more than fully funded with a forecasted total payout ratio of approximately 90%. As we have previously indicated, our intent is to allocate any excess cash generated beyond the capital program and dividend towards debt reduction, targeting a debt-to-FFO leverage ratio of 1.5 times or lower. In Q2 2019, we negotiated an extension to our $2.1 billion revolving credit facility to extend the maturity to May 31, 2023. The closing of the amendment is expected to take place before the end of April, 2019.

Q1 2019 Operations Review

Europe

In France, Q1 2019 production averaged 11,470 boe/d, which was up slightly from the prior quarter. Initial results from our 2019 workover program have exceeded our expectations, with one recompletion in the Aquitaine Basin yielding an initial 30-day rate of 600 bbls/d. Production contributions from the 2018 drilling program in the Champotran field continue to outperform internal estimates. Our 2019 Champotran drilling program commenced during the first quarter, as we drilled and completed three (3.0 net) wells. These wells are expected to be brought on production in late April, while drilling of the final (1.0 net) well of the program is ongoing.

In the Netherlands, Q1 2019 production averaged 8,677 boe/d, representing a 1% decrease from the prior quarter. We continue to make progress on the permitting for our two (1.0 net) 2019 planned wells. We received the drilling permit for the Weststellingwerf well during the first quarter, and are currently awaiting regulatory decisions on two additional wells, which should enable us to execute our planned two-well program for this year.

In Ireland, production averaged approximately 52 mmcf/d (8,619 boe/d) in Q1 2019, a decrease of 1% from the prior quarter. We completed some minor projects and activities previously identified to increase uptime and optimize plant compression to increase gas throughput. We will continue to evaluate other optimization opportunities throughout 2019 as we build more first-hand knowledge as operator.

In Germany, production in Q1 2019 averaged 3,763 boe/d, an increase of 1% from the prior quarter. The increase is primarily due to better than expected results from workovers performed on our operated oil assets. Late in the quarter, we commenced drilling the Burgmoor Z5 well (46% working interest), marking the first operated drill by Vermilion in Germany. Drilling is expected to conclude around mid-year, with well testing thereafter. We have identified several other sizeable exploration prospects on our German land base and intend to drill at least one new well per year for the foreseeable future.

In Central and Eastern Europe ("CEE"), we had no production in the quarter. The Mh-Ny-07 well in Hungary watered out at its current location, and we are evaluating the economics of sidetracking the well to access remaining gas at a higher structural location. We have received all necessary permits for the 2019 Hungarian drilling program and are making steady progress on permitting for our Croatia and Slovakia drilling programs. We plan a 10 (7.0 net) well 2019 drilling program for Central and Eastern Europe and remain very confident in the growth outlook for this region.

North America

In Canada, production averaged 61,360 boe/d in Q1 2019, an increase of 1% from the prior quarter. The production increase was driven by continued strong operating performance across our Canadian assets including positive results from our drilling programs in both Saskatchewan and Alberta. We drilled or participated in 58 (54.9 net) wells in the first quarter of 2019, including 45 (41.9 net) wells in Saskatchewan and 12 (12.0 net) Mannville wells in Alberta. In Saskatchewan, we tied in 40 wells from the Q1 program. Of the wells that have been on production for more than 15 days, we achieved an average rate of 162 boe/d (71% oil) on the Midale wells and 109 boe/d (90% oil) on the open hole Frobisher wells. In Alberta, we tied in 11 wells from the Q1 program, including ten Mannville wells that have been on production for more than 15 days achieving an average rate of 790 boe/d (40% oil, condensate and NGLs). The results from our Q1 2019 drilling program in both Saskatchewan and Alberta continue to perform at or above our expectations.

In the United States, Q1 2019 production averaged 3,653 boe/d, an increase of 3% from the prior quarter. The increase was primarily due to a full quarter contribution from our first Hilight well drilled in the prior quarter, which continues to perform in line with our expectations. We commenced our 2019 eight (7.6 net) well drilling program in the Hilight Turner Sands by drilling three (3.0 net) horizontal wells during the quarter. We are in the process of completing and testing these wells and plan to drill the remaining five (4.6 net) Hilight wells in the second and third quarters.

Australia

In Australia, production averaged 5,862 bbl/d in Q1 2019, an increase of 40% from the previous quarter primarily due to the contribution from the two (2.0 net) well program completed at the end of January 2019. The wells began producing in early February 2019 and continue to perform in line with our expectations. We produce these two wells intermittently at restricted rates in order to maximize long-term value and to manage to our annual production target of 6,000 bbl/d. Production in Q1 2019 was partially offset by weather related downtime, as two cyclones resulted in the platform being shut down for 11 days during the quarter.

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 April 23, 2019, we currently have 33% of our expected net-of-royalty production hedged for Q2 2019. Over half of the Q2 2019 corporate hedge position consists of two-way collars and three-way structures, which allow participation in price increases, up to contract ceilings.

We have currently hedged 69% of anticipated European natural gas volumes for Q2 2019. We have also hedged 66% and 49% of our anticipated full-year 2019 and 2020 European natural gas volumes, respectively, at prices which are expected to provide for strong project economics and free cash flows. At present 30% of our Q2 2019, and 26% of our full year 2019 oil production is hedged. For Q2 2019, 27% 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 14% of our North American production is located in Saskatchewan and Wyoming.

Sustainability

Sustainability is central to Vermilion's corporate strategy, as illustrated by the constitution of our Sustainability Committee by Vermilion's Board of Directors. We are pleased to note continued external confirmation of our progress in this realm. Our ISS Governance QualityScore increased from 3 to 2 (where a decile score of 1 indicates lowest governance risk), while our Environment and Social QualityScores remain at 1 and 2 respectively. This reflects our ongoing dedication to strong performance on ESG factors.

(signed "Anthony Marino")

Anthony Marino
President & Chief Executive Officer
April 25, 2019

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

Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated April 25, 2019, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three months ended March 31, 2019 compared with the corresponding period in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three months ended March 31, 2019 and the audited consolidated financial statements for the year 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 months ended March 31, 2019 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with IAS 31, "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 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 lease obligations which are secured by a corresponding right-of-use asset. Please see "Capital disclosures" in the "Notes to the Condensed Consolidated 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. The 2019 total budget and production guidance remain unchanged, although we have deferred some activity to later in the year and reallocated capital between business units, the breakdown of which can be found in our corporate presentation located on our website.

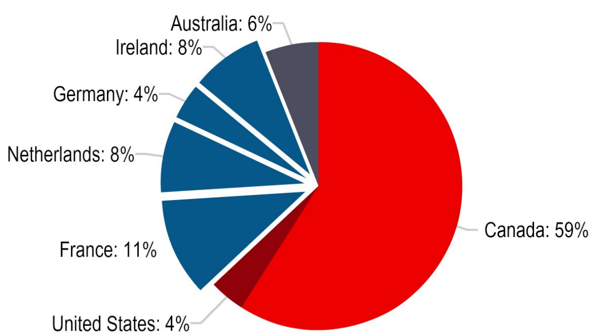
The following table summarizes our guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2019 Guidance			
2019 Guidance	October 25, 2018	530	101,000 to 106,000

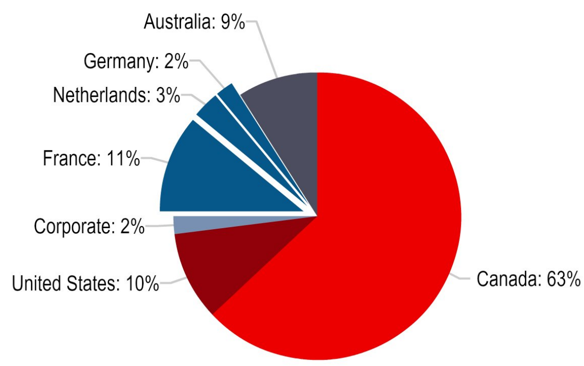
Vermilion's Business

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.

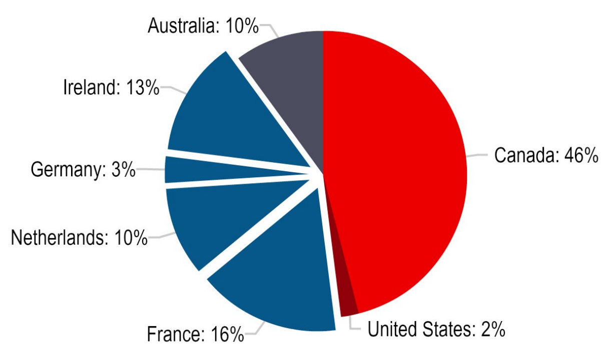
Q1 2019 production of 103,404 boe/d by business unit



Q1 2019 capital expenditures of $202MM by business unit



Q1 2019 fund flows from operations of $254MM by business unit



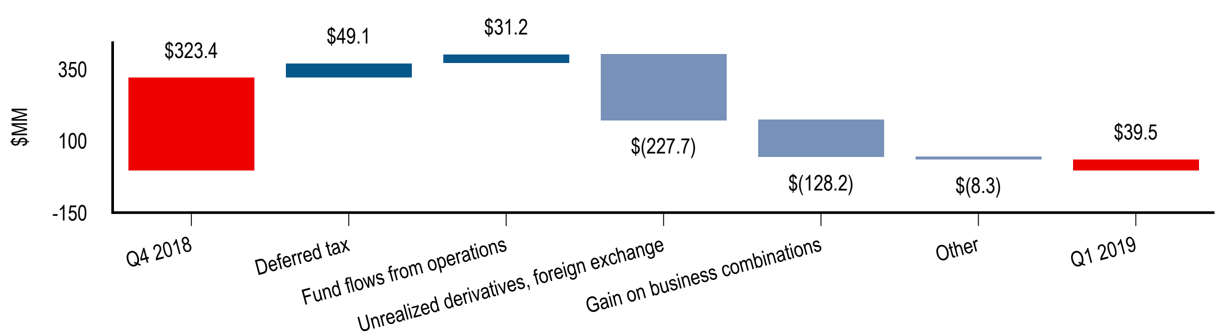
Consolidated Results Overview

	Q1 2019	Q4 2018	Q1 2018	Q1/19 vs. Q4/18	Q1/19 vs. Q1/18
Production					
Crude oil and condensate (bbls/d)	**49,181**	47,678	27,008	3.2%	82.1%
NGLs (bbls/d)	**7,897**	7,815	5,126	1.0%	54.1%
Natural gas (mmcf/d)	**277.96**	276.77	228.20	0.4%	21.8%
Total (boe/d)	**103,404**	101,621	70,167	1.8%	47.4%
Sales					
Crude oil and condensate (bbls/d)	**51,068**	47,620	26,001	7.2%	96.4%
NGLs (bbls/d)	**7,897**	7,815	5,126	1.0%	54.1%
Natural gas (mmcf/d)	**277.96**	276.77	228.20	0.4%	21.8%
Total (boe/d)	**105,291**	101,563	69,159	3.7%	52.2%
(Draw) build in inventory (mbbls)	**(170)**	5	90		
Financial metrics					
Fund flows from operations ($M)	**253,572**	222,342	160,415	14.0%	58.1%
Per share ($/basic share)	**1.66**	1.45	1.31	14.5%	26.7%
Net earnings	**39,547**	323,373	24,740	(87.8)%	59.9%
Per share ($/basic share)	**0.26**	2.12	0.20	(87.7)%	30.0%
Net debt ($M)	**2,000,144**	1,929,529	1,525,562	3.7%	31.1%
Cash dividends ($/share)	**0.690**	0.690	0.645	—%	7.0%
Activity					
Capital expenditures ($M)	**202,053**	163,580	128,465	23.5%	57.3%
Acquisitions ($M)	**16,027**	2,689	93,078		
Gross wells drilled	**66.00**	73.00	29.00		
Net wells drilled	**62.94**	45.08	27.69		

Financial performance review

Q1 2019 vs. Q4 2018

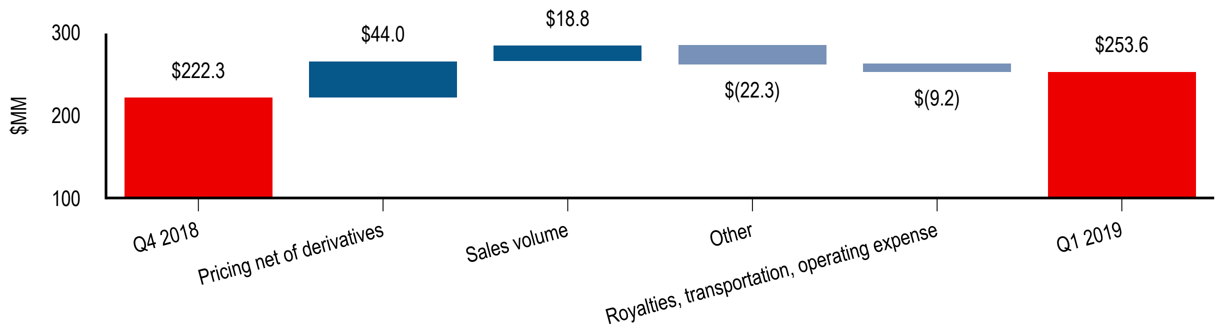
Net earnings of $39.5MM in Q1 2019 compared to $323.4MM in Q4 2018



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

- We recorded net earnings for Q1 2019 of $39.5 million ($0.26/basic share) compared to net earnings of $323.4 million ($2.12/basic share) in Q4 2018. This quarter-over-quarter decrease in net earnings was primarily attributable to lower net gains on unrealized derivatives and foreign exchange, as well as the absence of $128.2 million in gains recorded on business combinations that were present in Q4 2018. These decreases were partially offset by a $49.1 million decrease in deferred tax expense and a $31.2 million increase in fund flows from operations.

14% increase in fund flows from operations from Q4 2018 to Q1 2019

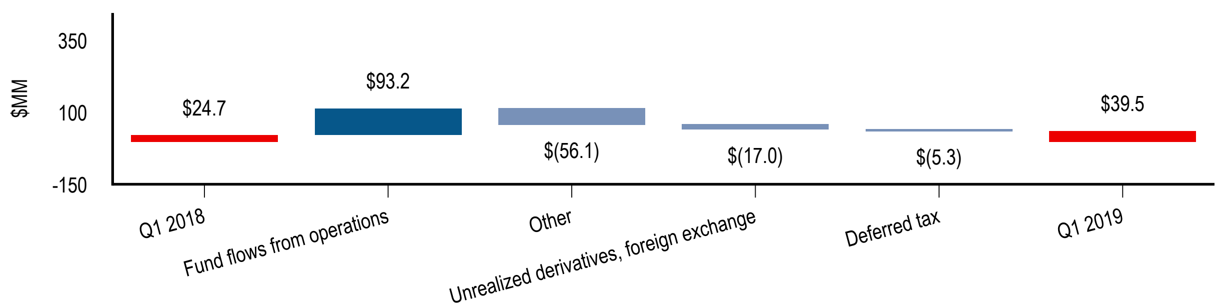


"Other" contains general and administration, corporate income taxes, interest, realized foreign exchange, and realized other

- We generated fund flows from operations of $253.6 million during Q1 2019, an increase of 14% from Q4 2018. This quarter-over-quarter increase was primarily due to higher Canadian realized oil prices and increased sales volumes during the current period.

Q1 2019 vs. Q1 2018

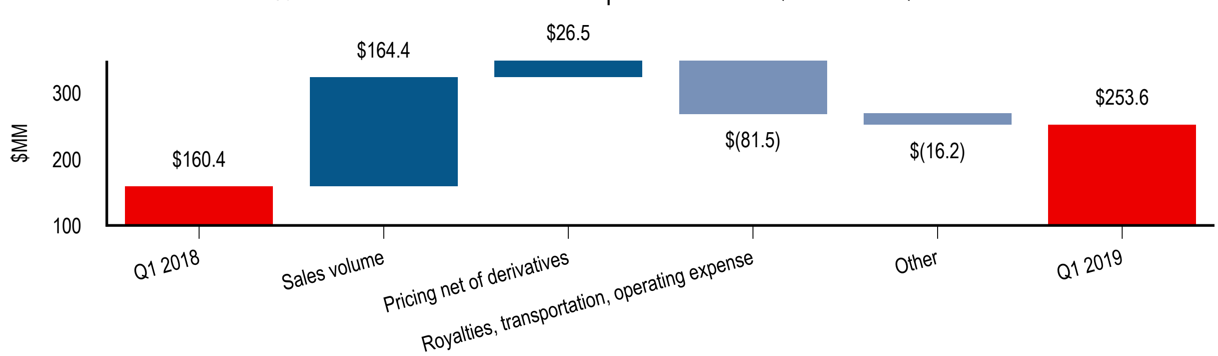
Net earnings of $39.5MM in Q1 2019 compared to $24.7MM in Q1 2018



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

- We recorded net earnings for Q1 2019 of $39.5 million ($0.26/basic share) compared to net earnings of $24.7 million ($0.20/basic share) in Q1 2018. The net earnings growth was the result of a 58% increase in fund flows from operations driven by increased sales volumes in Q1 2019 as compared to Q1 2018, partially offset by higher depletion and depreciation associated with higher sales volumes.

58% increase in fund flows from operations from Q1 2018 to Q1 2019



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

- Fund flows from operations increased 58% in Q1 2019 versus Q1 2018, which equated to a 27% increase on per basic share basis. This year-over-year increase was the result of a 52% increase in sales volumes. In addition, fund flows from operations benefited from an increased sales netback despite declines in commodity prices as we increased our production weighting towards higher priced crude oil. These increases were partially offset by incremental expense associated with the higher volumes.

Production review

Q1 2019 vs. Q4 2018

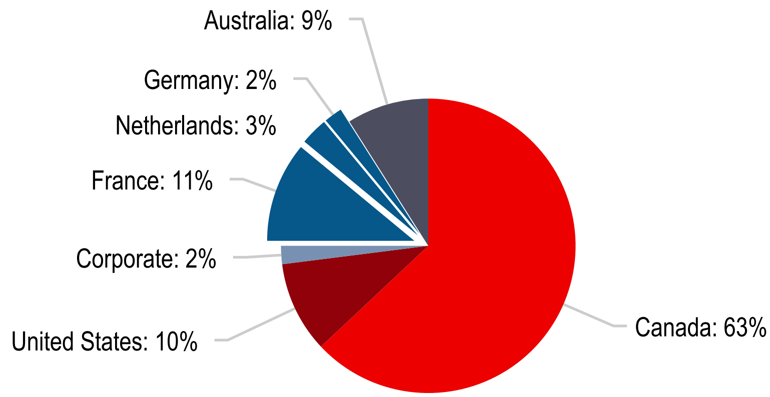
- Consolidated average production of 103,404 boe/d during Q1 2019 increased 2% versus Q4 2018. The increase in production was primarily attributable to the two new Australia wells brought on production in Q1 2019, and growth in Canada and the United States.

Q1 2019 vs. Q1 2018

- Consolidated average production of 103,404 boe/d in Q1 2019 represented an increase of 47% from Q1 2018 due to growth in Canada, the United States, and Australia. In Canada, year-over-year growth was the result of acquisitions in 2018 and continued development of our Mannville condensate-rich resource play and southeast Saskatchewan light oil development. In the United States, production growth resulted from an acquisition in Q3 2018 and organic drilling activity. Production in Australia increased due to the two-well drilling program completed during the quarter.

Activity review

Q1 2019 capital expenditures of $202MM by business unit



- For the three months ended March 31, 2019, capital expenditures of $202.1 million primarily related to activity in Canada, France, the United States and Australia. In Canada, capital expenditures of $128.1 million included the drilling of 58.0 (54.9 net) wells, including 45 (41.9 net) wells in Saskatchewan and 12 (12.0 net) Mannville wells in Alberta. In France, capital expenditures of $22.1 million related to the drilling of three (3.0 net) Champotran wells and our 2019 workover program. Capital expenditures of $20.0 million in the United States related to the drilling of three (3.0 net) Turner horizontal wells in the Hilight field. In Australia, capital expenditures of $18.9 million related to the completion of the two (2.0 net) well drilling program, which commenced in Q4 2018.

Sustainability review

Dividends

- Declared dividends of $0.23 per common share per month for Q1 2019, resulting in total dividends declared of $0.69 per common share for the three months ended March 31, 2019.

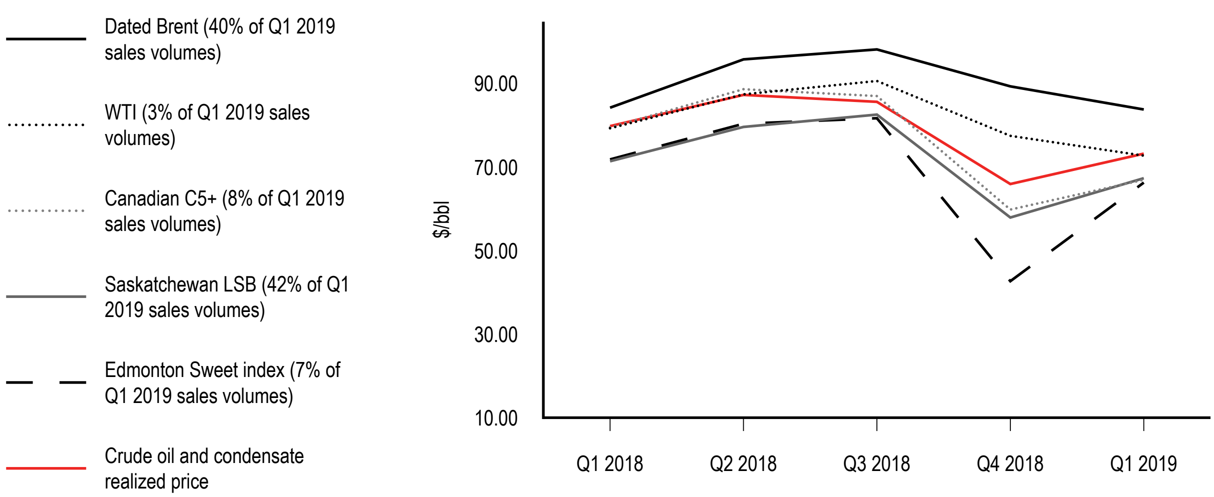
Long-term debt and net debt

- Long-term debt increased from $1.8 billion as at December 31, 2018 to $1.9 billion as at March 31, 2019. 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 March 31, 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 annualized fund flows from operations decreased in Q1 2019 to 1.97 times (2018 - 2.38 times) as the increase in net debt was more than offset by increased fund flows from operations.

Commodity Prices

	Q1 2019	Q4 2018	Q1 2018	Q1/19 vs. Q4/18	Q1/19 vs. Q1/18
Crude oil					
WTI ($/bbl)	**72.97**	77.71	79.52	(6.1)%	(8.2)%
WTI (US $/bbl)	**54.90**	58.81	62.87	(6.6)%	(12.7)%
Edmonton Sweet index ($/bbl)	**66.53**	42.96	72.07	54.9%	(7.7)%
Edmonton Sweet index (US $/bbl)	**50.05**	32.51	56.98	54.0%	(12.2)%
Saskatchewan LSB index ($/bbl)	**67.58**	58.18	71.63	16.2%	(5.7)%
Saskatchewan LSB index (US $/bbl)	**50.84**	44.03	56.63	15.5%	(10.2)%
Canadian C5+ Condensate index ($/bbl)	**67.20**	60.08	79.73	11.9%	(15.7)%
Canadian C5+ Condensate index (US $/bbl)	**50.56**	45.47	63.04	11.2%	(19.8)%
Dated Brent ($/bbl)	**84.01**	89.54	84.44	(6.2)%	(0.5)%
Dated Brent (US $/bbl)	**63.20**	67.76	66.76	(6.7)%	(5.3)%
Natural gas					
AECO ($/mcf)	**2.62**	1.56	2.08	67.9%	26.0%
NBP ($/mcf)	**8.33**	11.03	9.96	(24.5)%	(16.4)%
NBP (€/mcf)	**5.52**	7.31	6.41	(24.5)%	(13.9)%
TTF ($/mcf)	**8.14**	10.91	9.59	(25.4)%	(15.1)%
TTF (€/mcf)	**5.39**	7.23	6.17	(25.4)%	(12.6)%
Henry Hub ($/mcf)	**4.19**	4.82	3.80	(13.1)%	10.3%
Henry Hub (US $/mcf)	**3.15**	3.65	3.00	(13.7)%	5.0%
Average exchange rates					
CDN $/US $	**1.33**	1.32	1.26	0.8%	5.6%
CDN $/Euro	**1.51**	1.51	1.55	—%	(2.6)%
Realized Prices					
Crude oil and condensate ($/bbl)	**73.45**	66.19	80.03	11.0%	(8.2)%
NGLs ($/bbl)	**22.49**	25.69	25.37	(12.5)%	(11.4)%
Natural gas ($/mcf)	**5.10**	5.83	5.81	(12.5)%	(12.2)%
Total ($/boe)	**50.77**	48.90	51.13	3.8%	(0.7)%

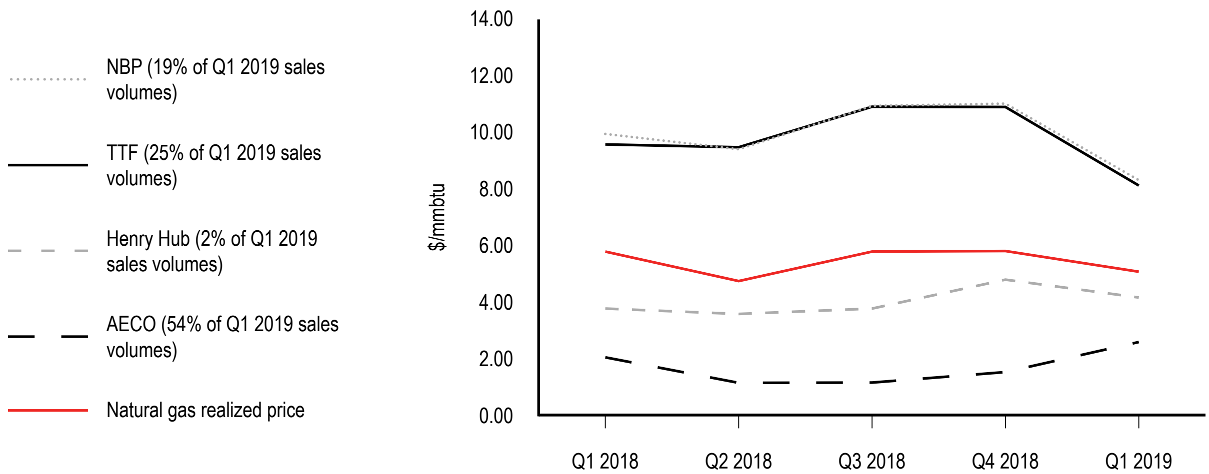
Q1 2019 realized crude oil and condensate price was a $0.48/bbl premium to WTI



- Crude oil prices recovered throughout Q1 2019 relative to the end of 2018, driven by lower global supply and an easing of macroeconomic concerns. Despite stronger prices by the end of Q1 2019, quarter-over-quarter WTI and Brent each decreased by 6% in Canadian dollar terms. For the three months ended March 31, 2019, WTI and Brent in Canadian dollar terms decreased by 8% and 1%, respectively, versus the comparable period in the prior year.

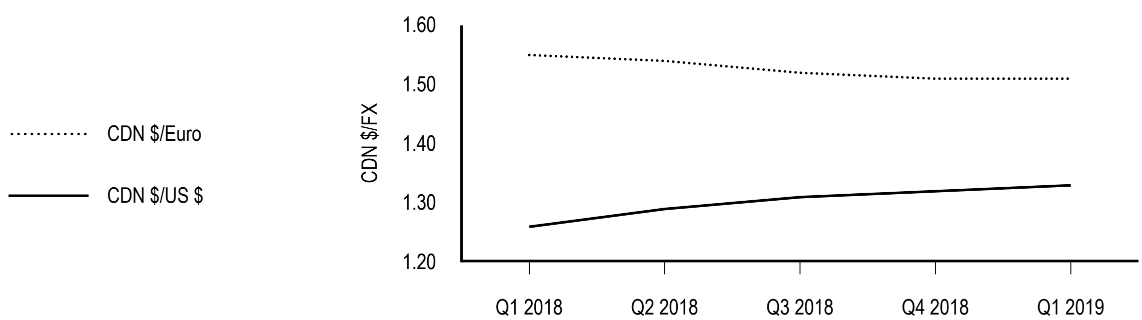
- The Government of Alberta's temporary curtailment of oil production improved the Western Canadian takeaway balance and positively impacted crude oil differentials in Q1 2019 versus Q4 2018. The Edmonton Sweet differential narrowed by $28.31/bbl and the Saskatchewan LSB differential narrowed by $14.14/bbl.
- Vermilion's crude oil production benefits from light oil pricing and no exposure to significantly discounted heavy crude oil. Approximately 40% of our Q1 2019 crude oil and condensate production was priced at the Dated Brent index (which averaged a premium to WTI of US$8.30/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+ 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. As a result, our Q1 2019 consolidated crude oil and condensate realized price of $73.45/bbl represented a $0.48 premium to WTI and a 10% premium to the Edmonton Sweet index.

Q1 2019 realized natural gas price was a $2.48/mcf premium to AECO



- European natural gas prices (TTF and NBP) declined by approximately 25% and 15% in Q1 2019 compared to Q4 2018 and Q1 2018 due to warmer than normal winter weather and growth in LNG imports.
- Natural gas prices at AECO in Q1 2019 increased by 68% and 26% compared to Q4 2018 and Q1 2018, respectively. A prolonged spell of cold weather in Western Canada increased domestic demand in the current quarter, which at times alleviated AECO's egress challenges.
- For Q1 2019, average European natural gas prices represented a $5.62/mcf premium to AECO and a $4.05/mcf premium to Henry Hub pricing. Approximately 44% of our natural gas production in Q1 2019 benefited from this premium European pricing. As a result, our consolidated natural gas realized price was a $2.48/mcf premium to AECO and a $0.91/mcf premium to Henry Hub pricing.

Quarter-over-quarter, the Canadian dollar was relatively flat versus the Euro and USD



- For the three months ended March 31, 2019, the Canadian dollar weakened by 1% against the US dollar quarter-over-quarter.
- For the three months ended March 31, 2019, the Canadian dollar remained flat versus 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) - in development phase
  - 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 ($M except as indicated)	Q1 2019	Q4 2018	Q1 2018	Q1/19 vs. Q4/18	Q1/19 vs. Q1/18
Production and sales					
Crude oil and condensate (bbls/d)	**29,164**	29,557	9,272	(1.3)%	214.5%
NGLs (bbls/d)	**6,968**	6,816	5,106	2.2%	36.5%
Natural gas (mmcf/d)	**151.37**	146.65	106.21	3.2%	42.5%
Total (boe/d)	**61,360**	60,814	32,078	0.9%	91.3%
Production mix (% of total)					
Crude oil and condensate	**48%**	49%	29%		
NGLs	**11%**	11%	16%		
Natural gas	**41%**	40%	55%		
Activity					
Capital expenditures	**128,055**	90,211	69,115	42.0%	85.3%
Acquisitions	**14,660**	12,233	90,250		
Gross wells drilled	**58.00**	72.00	18.00		
Net wells drilled	**54.94**	44.08	16.69		
Financial results					
Sales	**220,156**	186,308	92,933	18.2%	136.9%
Royalties	**(25,331)**	(25,584)	(9,848)	(1.0)%	157.2%
Transportation	**(10,692)**	(11,129)	(4,540)	(3.9)%	135.5%
Operating	**(63,604)**	(62,064)	(24,096)	2.5%	164.0%
General and administration	**(2,719)**	(2,150)	(700)	26.5%	288.4%
Fund flows from operations	**117,810**	85,381	53,749	38.0%	119.2%
Netbacks ($/boe)					
Sales	**39.87**	33.30	32.19	19.7%	23.9%
Royalties	**(4.59)**	(4.57)	(3.41)	0.4%	34.6%
Transportation	**(1.94)**	(1.99)	(1.57)	(2.5)%	23.6%
Operating	**(11.52)**	(11.09)	(8.35)	3.9%	38.0%
General and administration	**(0.49)**	(0.38)	(0.24)	28.9%	104.2%
Fund flows from operations netback	**21.33**	15.27	18.62	39.7%	14.6%
Realized prices					
Crude oil and condensate ($/bbl)	**65.47**	54.04	75.05	21.2%	(12.8)%
NGLs ($/bbl)	**22.12**	25.53	25.33	(13.4)%	(12.7)%
Natural gas ($/mcf)	**2.47**	1.73	1.95	42.8%	26.7%
Total ($/boe)	**39.87**	33.30	32.19	19.7%	23.9%
Reference prices					
WTI (US $/bbl)	**54.90**	58.81	62.87	(6.6)%	(12.7)%
Edmonton Sweet index ($/bbl)	**66.53**	42.96	72.07	54.9%	(7.7)%
Saskatchewan LSB index ($/bbl)	**67.58**	58.18	71.63	16.2%	(5.7)%
Canadian C5+ Condensate index ($/bbl)	**67.20**	60.08	79.73	11.9%	(15.7)%
AECO ($/mcf)	**2.62**	1.56	2.08	67.9%	26.0%

Production

- Q1 2019 production increased 1% from the prior quarter due to strong operating performance across our asset base, positive results from our Q4 2018 and Q1 2019 drilling programs and lower than anticipated third party facility restrictions. Quarterly production increased 91% year-over-year, with the most important driver being our acquisition of Spartan Energy Corp. in May 2018.
- Production in Alberta averaged approximately 35,200 boe/d in Q1 2019, an increase of 4% quarter-over-quarter.
- Production in Saskatchewan averaged approximately 26,200 boe/d in Q1 2019, a decrease of 2% quarter-over-quarter.

Activity review

- Vermilion drilled 57 (54.4 net) operated wells and participated in the drilling of one (0.5 net) non-operated well in Canada during Q1 2019.

  Alberta

  – In Q1 2019, we drilled 13 (13.0 net) operated wells, completed 16 (16.0 net) operated wells, and brought on production 18 (17.9 net) operated wells in Alberta.
  – In 2019, we plan to drill or participate in 20 (17.7 net) wells in Alberta.

  Saskatchewan

  – In Q1 2019, we drilled or participated in 44 (41.4 net) operated wells and one (0.5 net) non-operated wells, completed 45 (42.4 net) operated wells, and brought 43 (40.3 net) operated wells on production in Saskatchewan.
  – In 2019, we plan to drill or participate in 140 (125.9 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 index price in Saskatchewan and the Canadian Condensate C5+ and Edmonton Sweet index prices in Alberta). The realized price of our natural gas in Canada is based on the AECO index.
- Q1 2019 sales per boe increased 20% compared to Q4 2018 despite a decrease in the WTI benchmark price due to narrowing crude oil differentials in Western Canada. Quarter-over-quarter, our crude oil and condensate production mix remained stable at approximately 50% of production.
- Q1 2019 sales per boe increased versus Q1 2018 due to an increased weighting towards higher-priced crude oil and condensate production, despite a decrease in crude oil and condensate pricing.

Royalties

- Royalties as a percentage of sales of 11.5% for the three months ended March 31, 2019 decreased from 13.7% in Q4 2018 due to lower Alberta crude oil par pricing in Q1 2019 coupled with lower average royalty rates for new wells brought on production.
- Q1 2019 royalties as a percentage of sales of 11.5% increased from 10.6% in the comparable period in 2018 due to the impact of increased oil production, which has higher associated royalty rates.

Transportation

- Transportation expense on a dollar and per unit basis remained relatively consistent for Q1 2019 versus Q4 2018.
- Transportation expense for the three months ended March 31, 2019 increased on a dollar and per unit basis versus the comparable period in 2018 due to an increase in crude oil production that incurs higher transportation expense.

Operating

- Operating expense remained consistent in Q1 2019 versus Q4 2018.
- For the three months ended March 31, 2019, operating expense increased on both a dollar and 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 Q1 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, infill drilling, and secondary recovery opportunities.

Operational and financial review

France business unit ($M except as indicated)	Q1 2019	Q4 2018	Q1 2018	Q1/19 vs. Q4/18	Q1/19 vs. Q1/18
Production					
Crude oil (bbls/d)	**11,342**	11,317	11,037	0.2%	2.8%
Natural gas (mmcf/d)	**0.77**	0.82	—	(6.1)%	100.0%
Total (boe/d)	**11,470**	11,454	11,037	0.1%	4.0%
Sales					
Crude oil (bbls/d)	**11,256**	10,975	9,893	3.0%	13.8%
Natural gas (mmcf/d)	**0.77**	0.82	—	(6.1)%	100.0%
Total (boe/d)	**11,384**	11,111	9,893	2.5%	15.1%
Inventory (mbbls)					
Opening crude oil inventory	**325**	293	197		
Crude oil production	**1,021**	1,041	993		
Crude oil sales	**(1,014)**	(1,009)	(890)		
Closing crude oil inventory	**332**	325	300		
Activity					
Capital expenditures	**22,086**	17,008	29,927	29.9%	(26.2)%
Gross wells drilled	**3.00**	—	5.00		
Net wells drilled	**3.00**	—	5.00		
Financial results					
Sales	**82,702**	85,889	72,745	(3.7)%	13.7%
Royalties	**(11,283)**	(11,976)	(9,438)	(5.8)%	19.5%
Transportation	**(3,170)**	(3,242)	(2,358)	(2.2)%	34.4%
Operating	**(15,736)**	(14,015)	(13,049)	12.3%	20.6%
General and administration	**(3,655)**	(3,792)	(3,513)	(3.6)%	4.0%
Current income taxes	**(7,700)**	(884)	(2,053)	771.0%	275.1%
Fund flows from operations	**41,158**	51,980	42,334	(20.8)%	(2.8)%
Netbacks ($/boe)					
Sales	**80.72**	84.02	81.70	(3.9)%	(1.2)%
Royalties	**(11.01)**	(11.72)	(10.60)	(6.1)%	3.9%
Transportation	**(3.09)**	(3.17)	(2.65)	(2.5)%	16.6%
Operating	**(15.36)**	(13.71)	(14.66)	12.0%	4.8%
General and administration	**(3.57)**	(3.71)	(3.95)	(3.8)%	(9.6)%
Current income taxes	**(7.52)**	(0.86)	(2.31)	774.4%	225.5%
Fund flows from operations netback	**40.17**	50.85	47.53	(21.0)%	(15.5)%
Reference prices					
Dated Brent (US $/bbl)	**63.20**	67.76	66.76	(6.7)%	(5.3)%
Dated Brent ($/bbl)	**84.01**	89.54	84.44	(6.2)%	(0.5)%

Production

- Q1 2019 production increased slightly from the prior quarter due to positive initial results from our 2019 workover program and continued strong performance from the 2018 Champotran wells. Quarterly production increased 4% year-over-year primarily due to production additions from our 2018 drilling program.

Activity review

- During Q1 2019, we drilled three (3.0 net) Champotran wells.
- In the second quarter of 2019, we plan to bring the new Champotran wells drilled in the first quarter of 2019 on production and drill the final Champotran well of our planned 2019 drilling campaign. In addition to the drilling and completion activity, 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.
- Q1 2019 sales per boe decreased versus both Q4 2018 and Q1 2018, consistent with the weakening in the Dated Brent reference price versus the comparable quarters.

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).
- Royalties as a percentage of sales was 13.6% in Q1 2019, relatively consistent with 13.9% in Q4 2018 and 13.0% in Q1 2018.

Transportation

- Transportation expense in Q1 2019 remained consistent with Q4 2018.
- Transportation expense for the three months ended March 31, 2018 increased versus the comparable period in the prior year, primarily due increased crude oil shipments in Q1 2019.

Operating

- Operating expense in Q1 2019 was higher than Q4 2018 and Q1 2018 on a dollar and per unit basis due primarily to higher electricity prices in the current quarter.

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 13% to 17% 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 ($M except as indicated)	Q1 2019	Q4 2018	Q1 2018	Q1/19 vs. Q4/18	Q1/19 vs. Q1/18
Production and sales					
Condensate (bbls/d)	**93**	112	77	(17.0)%	20.8%
Natural gas (mmcf/d)	**51.51**	51.82	44.79	(0.6)%	15.0%
Total (boe/d)	**8,677**	8,749	7,541	(0.8)%	15.1%
Activity					
Capital expenditures	**6,349**	2,454	3,278	158.7%	93.7%
Acquisitions	**908**	(7,860)	2,760		
Gross wells drilled	**—**	—	—		
Net wells drilled	**—**	—	—		
Financial results					
Sales	**40,586**	52,937	36,186	(23.3)%	12.2%
Royalties	**(614)**	(537)	(850)	14.3%	(27.8)%
Operating	**(8,285)**	(6,765)	(7,685)	22.5%	7.8%
General and administration	**(892)**	(709)	(773)	25.8%	15.4%
Current income taxes	**(4,200)**	(7,492)	(5,805)	(43.9)%	(27.6)%
Fund flows from operations	**26,595**	37,434	21,073	(29.0)%	26.2%
Netbacks ($/boe)					
Sales	**51.97**	65.77	53.31	(21.0)%	(2.5)%
Royalties	**(0.79)**	(0.67)	(1.25)	17.9%	(36.8)%
Operating	**(10.61)**	(8.40)	(11.32)	26.3%	(6.3)%
General and administration	**(1.14)**	(0.88)	(1.14)	29.5%	—%
Current income taxes	**(5.38)**	(9.31)	(8.55)	(42.2)%	(37.1)%
Fund flows from operations netback	**34.05**	46.51	31.05	(26.8)%	9.7%
Realized prices					
Condensate ($/bbl)	**67.10**	69.95	68.64	(4.1)%	(2.2)%
Natural gas ($/mcf)	**8.63**	10.95	8.86	(21.2)%	(2.6)%
Total ($/boe)	**51.97**	65.77	53.31	(21.0)%	(2.5)%
Reference prices					
TTF ($/mcf)	**8.14**	10.91	9.59	(25.4)%	(15.1)%
TTF (€/mcf)	**5.39**	7.23	6.17	(25.4)%	(12.6)%

Production

- Q1 2019 production decreased 1% from the prior quarter due to planned downtime associated with several planned workovers we performed throughout the quarter. Quarterly production increased 15% year-over-year primarily due to the contribution from the Eesveen-02 well (60% working interest), which we brought on production in Q3 2018.

Activity review

- In Q1 2019, we completed several planned workovers across our asset base, which contributed to planned downtime. We received the drilling permit for the Weststellingwerf well during the first quarter, and are currently awaiting regulatory decisions on two additional wells, which should enable us to execute our planned two-well program for this year.

Sales

- The price of our natural gas in the Netherlands is based on the TTF index.
- Q1 2019 sales decreased on a dollar and per unit basis versus Q4 2018 consistent with the decrease in the TTF reference price.
- For the three months ended March 31, 2019, sales on a per unit basis decreased year-over-year as a result of a decrease in the TTF reference price in Q1 2019 versus Q1 2018.

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 the three months ended March 31, 2019 represented 1.5% of sales. Royalties are expected to decrease going forward due to the acquisition of certain royalty rights with an effective date of March 1, 2019.

Transportation

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

Operating

- Q1 2018 operating expense increased on a dollar and per unit basis versus Q4 2018 due to increased maintenance activity and surface rights payments during the quarter.
- For the three months ended March 31, 2019, operating expense increased on a dollar basis versus the comparable period in 2018 primarily due to incremental expense associated with the year-over-year production increase. On a per unit basis, operating expense decreased due to the impact of fixed costs being spread over higher volumes.

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 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 12% to 16% 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 18, 2018, the Dutch government approved the 2019 Tax Plan. The Bill provides for reduced corporate tax rates from 25.0% to 20.5% by 2021, with the first reduction planned for 2020 to 22.55%. Due to the tax regime applicable to natural gas producers in the Netherlands, the reduction to the corporate tax rate is not expected to have a material impact to Vermilion taxes in the Netherlands.

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 ($M except as indicated)	Q1 2019	Q4 2018	Q1 2018	Q1/19 vs. Q4/18	Q1/19 vs. Q1/18
Production					
Crude oil (bbls/d)	**978**	913	1,078	7.1%	(9.3)%
Natural gas (mmcf/d)	**16.71**	16.94	16.19	(1.4)%	3.2%
Total (boe/d)	**3,763**	3,736	3,777	0.7%	(0.4)%
Sales					
Crude oil (bbls/d)	**1,052**	970	1,307	8.5%	(19.5)%
Natural gas (mmcf/d)	**16.71**	16.94	20.12	(1.4)%	(16.9)%
Total (boe/d)	**3,837**	3,794	4,006	1.1%	(4.2)%
Production mix (% of total)					
Crude oil	**26%**	24%	29%		
Natural gas	**74%**	76%	71%		
Activity					
Capital expenditures	**3,044**	4,580	2,415	(33.5)%	26.0%
Acquisitions	**416**	706	—		
Financial results					
Sales	**19,368**	21,897	20,501	(11.5)%	(5.5)%
Royalties	**(2,223)**	(1,190)	(1,737)	86.8%	28.0%
Transportation	**(1,672)**	(1,452)	(1,998)	15.2%	(16.3)%
Operating	**(5,920)**	(6,615)	(6,186)	(10.5)%	(4.3)%
General and administration	**(1,913)**	(2,308)	(1,558)	(17.1)%	22.8%
Fund flows from operations	**7,640**	10,332	9,022	(26.1)%	(15.3)%
Netbacks ($/boe)					
Sales	**56.09**	62.74	56.86	(10.6)%	(1.4)%
Royalties	**(6.44)**	(3.41)	(4.82)	88.9%	33.6%
Transportation	**(4.84)**	(4.16)	(5.54)	16.3%	(12.6)%
Operating	**(17.14)**	(18.95)	(17.16)	(9.6)%	(0.1)%
General and administration	**(5.54)**	(6.61)	(4.32)	(16.2)%	28.2%
Fund flows from operations netback	**22.13**	29.61	25.02	(25.3)%	(11.6)%
Realized prices					
Crude oil ($/bbl)	**78.50**	75.53	79.04	3.9%	(0.7)%
Natural gas ($/mcf)	**7.94**	9.72	7.69	(18.3)%	3.3%
Total ($/boe)	**56.09**	62.74	56.86	(10.6)%	(1.4)%
Reference prices					
Dated Brent (US $/bbl)	**63.20**	67.76	66.76	(6.7)%	(5.3)%
Dated Brent ($/bbl)	**84.01**	89.54	84.44	(6.2)%	(0.5)%
TTF ($/mcf)	**8.14**	10.91	9.59	(25.4)%	(15.1)%
TTF (€/mcf)	**5.39**	7.23	6.17	(25.4)%	(12.6)%

Production

- Q1 2019 production increased 1% from the prior quarter due to better than anticipated results from workovers performed on some of our operated oil assets. Quarterly production was relatively consistent year-over-year.

Activity review

- During Q1 2019, we commenced drilling of the Burgmoor Z5 well (46% working interest), marking the first operated drill by Vermilion in Germany.
- In mid-2019, we plan to complete drilling the Burgmoor Z5 well, with well testing expected to be performed shortly thereafter. We also 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.
- Sales per boe for Q1 2019 decreased versus Q4 2018, and remained consistent with Q1 2018, consistent with fluctuations in crude oil and natural gas benchmark 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 were higher in Q1 2019 versus Q4 2018 and Q1 2018 due to an unfavorable prior period adjustment recorded in the current quarter.

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 Q1 2019 was higher than Q4 2018 due to higher volumes of crude oil transported in Q1 2019.
- Transportation expense for the three months ended March 31, 2019 decreased versus the comparable period in the prior year due to lower crude oil transported volumes in Q1 2019.

Operating

- Operating expense on a per unit basis in Q1 2019 was lower versus Q4 2018 due to lower gas treatment expenses in the current quarter.
- Operating expense on a per unit basis for the three months ended March 31, 2019 remained consistent versus the comparable period in the prior 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

- As a result of our tax pools in Germany, we do not expect to incur current income taxes for 2019 in the German 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 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 ($M except as indicated)	Q1 2019	Q4 2018	Q1 2018	Q1/19 vs. Q4/18	Q1/19 vs. Q1/18
Production and sales					
Natural gas (mmcf/d)	**51.71**	52.03	60.87	(0.6)%	(15.0)%
Total (boe/d)	**8,619**	8,672	10,144	(0.6)%	(15.0)%
Activity					
Capital expenditures	**11**	140	47	(92.1)%	(76.6)%
Acquisitions	**—**	(5,572)	—		
Financial results					
Sales	**39,792**	53,385	53,675	(25.5)%	(25.9)%
Transportation	**(1,166)**	(1,115)	(1,286)	4.6%	(9.3)%
Operating	**(3,810)**	(4,497)	(3,209)	(15.3)%	18.7%
General and administration	**(329)**	(2,037)	(1,309)	(83.8)%	(74.9)%
Fund flows from operations	**34,487**	45,736	47,871	(24.6)%	(28.0)%
Netbacks ($/boe)					
Sales	**51.30**	66.91	58.79	(23.3)%	(12.7)%
Transportation	**(1.50)**	(1.40)	(1.41)	7.1%	6.4%
Operating	**(4.91)**	(5.64)	(3.51)	(12.9)%	39.9%
General and administration	**(0.42)**	(2.55)	(1.43)	(83.5)%	(70.6)%
Fund flows from operations netback	**44.47**	57.32	52.44	(22.0)%	(15.0)%
Reference prices					
NBP ($/mcf)	**8.33**	11.03	9.96	(24.5)%	(16.4)%
NBP (€/mcf)	**5.52**	7.31	6.41	(24.5)%	(13.9)%

Production

- Q1 2019 production decreased 1% from the prior quarter. Quarterly production decreased 15% year-over-year due primarily to natural decline.

Activity review

- During Q1 2019, we completed some minor projects and activities to increase uptime and optimize plant compression to increase gas throughput.
- In 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 months ended March 31, 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 related to the Corrib project.
- Transportation expense for Q1 2019 remained consistent with Q4 2018. Q1 2019 transportation expense decreased versus the comparable quarter in the prior year due to a decrease in tariffs beginning in Q4 2018.

Operating

- Q1 2019 operating expense was lower versus Q4 2018 due to higher levels of offshore operations and terminal maintenance activity completed during Q4 2018.
- For the three months ended March 31, 2019, operating expense fluctuated versus the comparable period in 2018 due to the timing of maintenance activity.

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 ($M except as indicated)	Q1 2019	Q4 2018	Q1 2018	Q1/19 vs. Q4/18	Q1/19 vs. Q1/18
Production					
Crude oil (bbls/d)	**5,862**	4,174	4,971	40.4%	17.9%
Sales					
Crude oil (bbls/d)	**7,762**	4,401	4,878	76.4%	59.1%
Inventory (mbbls)					
Opening crude oil inventory	**189**	210	134		
Crude oil production	**528**	384	447		
Crude oil sales	**(699)**	(405)	(439)		
Closing crude oil inventory	**18**	189	142		
Activity					
Capital expenditures	**18,864**	43,760	4,449	(56.9)%	324.0%
Gross wells drilled	**2.00**	—	—		
Net wells drilled	**2.00**	—	—		
Financial results					
Sales	**63,582**	39,351	38,170	61.6%	66.6%
Operating	**(21,404)**	(15,757)	(13,048)	35.8%	64.0%
General and administration	**(1,039)**	(1,391)	(1,525)	(25.3)%	(31.9)%
Current income taxes	**(14,100)**	2,206	(5,518)	N/A	155.5%
Fund flows from operations	**27,039**	24,409	18,079	10.8%	49.6%
Netbacks ($/boe)					
Sales	**91.02**	97.19	86.94	(6.3)%	4.7%
Operating	**(30.64)**	(38.92)	(29.72)	(21.3)%	3.1%
General and administration	**(1.49)**	(3.44)	(3.47)	(56.7)%	(57.1)%
PRRT	**(14.89)**	5.98	(11.04)	N/A	34.9%
Corporate income taxes	**(5.30)**	(0.53)	(1.53)	900.0%	246.4%
Fund flows from operations netback	**38.70**	60.28	41.18	(35.8)%	(6.0)%
Reference prices					
Dated Brent (US $/bbl)	**63.20**	67.76	66.76	(6.7)%	(5.3)%
Dated Brent ($/bbl)	**84.01**	89.54	84.44	(6.2)%	(0.5)%

Production

- Q1 2019 production increased 40% quarter-over-quarter and 18% year-over-year due to the production contribution from the two (2.0 net) well drilling program we completed at the end of January 2019. Production was partially offset by weather related downtime, as two named cyclones resulted in the platform being shut down for 11 days during the quarter.
- Production volumes are managed within corporate targets while meeting customer demands and the requirements of long-term supply agreements.
- We continue to plan for long-term annual production levels of approximately 6,000 bbls/d.

Activity review

- In Q1 2019, we completed our two (2.0 net) well drilling program in January 2019 and the wells continue to perform in line with our expectations. The total cost of the program was $75 million, which was approximately $10 million over budget due to minor drilling complications and weather-related delays.
- In 2019, we will also continue to focus on adding value through asset optimization and proactive maintenance.

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Q1 2019 sales increased compared to both Q4 2018 and Q1 2018 due to increased sales volumes in the current quarter. Quarter-over-quarter, the increase in sales volumes was partially offset by lower sales per boe, consistent with a decrease in the Dated Brent reference price. Year-over-year, sales per boe increased slightly despite relatively consistent Dated Brent pricing due to the timing of sales in the quarter.

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

- Q1 2019 operating expense increased versus Q4 2018 and Q1 2018 due to higher crude oil production in Q1 2019. The impact of higher production volumes on fixed costs resulted in a reduction in per unit operating expense in Q1 2019 versus Q4 2018.

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 32% to 36% 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 September 2014.
- Interests include approximately 147,800 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 ($M except as indicated)	Q1 2019	Q4 2018	Q1 2018	Q1/19 vs. Q4/18	Q1/19 vs. Q1/18
Production and sales					
Crude oil (bbls/d)	**1,742**	1,605	574	8.5%	203.5%
NGLs (bbls/d)	**929**	998	20	(6.9)%	4,545.0%
Natural gas (mmcf/d)	**5.89**	5.65	0.15	4.2%	3,826.7%
Total (boe/d)	**3,653**	3,545	618	3.0%	491.1%
Production mix (% of total)					
Crude oil	**48%**	45%	93%		
NGLs	**25%**	28%	3%		
Natural gas	**27%**	27%	4%		
Activity					
Capital expenditures	**20,036**	2,881	15,868	595.5%	26.3%
Acquisitions	**43**	3,674	68		
Gross wells drilled	**3.00**	1.00	5.00		
Net wells drilled	**3.00**	1.00	5.00		
Financial results					
Sales	**14,897**	14,625	4,059	1.9%	267.0%
Royalties	**(3,933)**	(4,053)	(1,122)	(3.0)%	250.5%
Operating	**(3,432)**	(2,848)	(566)	20.5%	506.4%
General and administration	**(1,891)**	(1,396)	(1,176)	35.5%	60.8%
Fund flows from operations	**5,641**	6,328	1,195	(10.9)%	372.1%
Netbacks ($/boe)					
Sales	**45.31**	44.85	72.94	1.0%	(37.9)%
Royalties	**(11.96)**	(12.43)	(20.16)	(3.8)%	(40.7)%
Operating	**(10.44)**	(8.73)	(10.18)	19.6%	2.6%
General and administration	**(5.75)**	(4.28)	(21.13)	34.3%	(72.8)%
Fund flows from operations netback	**17.16**	19.41	21.47	(11.6)%	(20.1)%
Realized prices					
Crude oil ($/bbl)	**68.72**	70.78	76.56	(2.9)%	(10.2)%
NGLs ($/bbl)	**25.21**	26.81	36.24	(6.0)%	(30.4)%
Natural gas ($/mcf)	**3.80**	3.29	3.00	15.5%	3.0%
Total ($/boe)	**45.31**	44.85	72.94	1.0%	(37.9)%
Reference prices					
WTI (US $/bbl)	**54.90**	58.81	62.87	(6.6)%	(12.7)%
WTI ($/bbl)	**72.97**	77.71	79.52	(6.1)%	(8.2)%
Henry Hub (US $/mcf)	**3.15**	3.65	3.00	(13.7)%	5.0%
Henry Hub ($/mcf)	**4.19**	4.82	3.80	(13.1)%	10.3%

Production

- Q1 2019 production increased 3% from the prior quarter due to a full quarter contribution from our first Hilight well drilled in the prior quarter, partially offset by weather related downtime in both the Hilight and East Finn fields. Quarterly production increased 491% year-over-year primarily due to the production associated with an acquisition we completed in August 2018.

Activity

- During Q1 2019, we drilled three (3.0 net) Turner horizontal wells in the Hilight field and plan to complete these wells in the second quarter of 2019.
- In 2019, we plan to drill eight (7.6 net) Hilight Turner horizontal wells.

Sales

- The price of crude oil in the United States is directly linked to WTI, subject to local market differentials within the United States.
- Q1 2019 sales per boe remained consistent versus Q4 2018. Q1 2019 sales per boe decreased versus Q1 2018 due to an increase in natural gas production from assets acquired in 2018.

Royalties

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax.
- Royalties as a percentage of sales were consistent in Q1 2019 versus all comparable periods.

Operating

- The increase in operating expense in Q1 2019 versus Q4 2018 was due to the timing of maintenance activity. Increased operating expense in Q1 2019 versus Q1 2018 was due to incremental costs from the assets acquired in 2018.

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 US 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, including production, revenues, and expenditures relating to our first exploratory well in the South Battonya concession in Hungary.

Operational and financial review

Corporate ($M)	Q1 2019	Q4 2018	Q1 2018
Production and sales			
Natural gas (mmcf/d)	**—**	2.86	—
Total (boe/d)	**—**	477	—
Activity			
Capital expenditures	**3,608**	2,546	3,366
Acquisitions	**—**	(492)	—
Gross wells drilled	**—**	—	1.00
Net wells drilled	**—**	—	1.00
Financial results			
Sales	**—**	2,547	—
Royalties	**—**	(534)	—
Sales of purchased commodities	**29,539**	—	—
Purchased commodities	**(29,539)**	—	—
Operating	**(231)**	91	—
General and administration (expense) recovery	**(620)**	969	(1,174)
Current income taxes	**(150)**	646	(186)
Interest expense	**(20,979)**	(20,827)	(15,588)
Realized gain (loss) on derivatives	**10,348**	(28,319)	(17,715)
Realized foreign exchange (loss) gain	**(2,050)**	5,894	1,554
Realized other income	**6,884**	275	201
Fund flows from operations	**(6,798)**	(39,258)	(32,908)

Production review

- Production from our one Hungarian well in the Central and Eastern Europe business unit was shut-in during Q1 2019.

Activity review

- In Q1 2019, we continued preparations for our 2019 drills as we have received all necessary permits for the 2019 Hungarian drilling program and are making steady progress on the permitting for our Croatia and Slovakia drilling programs.

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 months ended March 31, 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 Q1 2019 remained consistent versus Q4 2018.
- For the three months ended March 31, 2019, interest expense increased versus the comparative period in 2018 due to higher drawings on the revolving credit facility.

Realized gain or loss on derivatives

- The realized gain on derivatives for the three months ended March 31, 2019 is related primarily to receipts for crude oil and European natural gas hedges.
- A listing of derivative positions as at March 31, 2019 is included in “Supplemental Table 2” of this MD&A.

Realized other income

- Realized other income recognized in Q1 2019 primarily relates to amounts received pursuant to a negotiated settlement of a legal matter in Canada..

Financial Performance Review

($M except per share)	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017
Petroleum and natural gas sales	**481,083**	456,939	508,411	394,498	318,269	317,341	248,505	271,391
Net earnings (loss)	**39,547**	323,373	(15,099)	(61,364)	24,740	8,645	(39,191)	48,264
Net earnings (loss) per share								
Basic	**0.26**	2.12	(0.10)	(0.46)	0.20	0.07	(0.32)	0.40
Diluted	**0.26**	2.10	(0.10)	(0.46)	0.20	0.07	(0.32)	0.39

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

	Q1 2019		Q4 2018		Q1 2018	
	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	**481,083**	**50.77**	456,939	48.90	318,269	51.13
Royalties	**(43,384)**	**(4.58)**	(43,874)	(4.70)	(22,995)	(3.69)
Petroleum and natural gas revenues	**437,699**	**46.19**	413,065	44.20	295,274	47.44
Transportation	**(16,700)**	**(1.76)**	(16,938)	(1.81)	(10,182)	(1.64)
Operating	**(122,422)**	**(12.92)**	(112,470)	(12.04)	(67,839)	(10.90)
General and administration	**(13,058)**	**(1.38)**	(12,814)	(1.37)	(11,728)	(1.88)
PRRT	**(10,400)**	**(1.10)**	2,422	0.26	(4,848)	(0.78)
Corporate income taxes	**(15,750)**	**(1.66)**	(7,946)	(0.85)	(8,714)	(1.40)
Interest expense	**(20,979)**	**(2.21)**	(20,827)	(2.23)	(15,588)	(2.50)
Realized gain (loss) on derivative instruments	**10,348**	**1.09**	(28,319)	(3.03)	(17,715)	(2.85)
Realized foreign exchange (loss) gain	**(2,050)**	**(0.22)**	5,894	0.63	1,554	0.25
Realized other income	**6,884**	**0.73**	275	0.03	201	0.03
Fund flows from operations	**253,572**	**26.76**	222,342	23.79	160,415	25.77

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 earnings:

	Q1 2019	Q4 2018	Q1 2018
Fund flows from operations	**253,572**	222,342	160,415
Equity based compensation	**(22,843)**	(16,979)	(19,750)
Unrealized (loss) gain on derivative instruments	**(14,277)**	273,096	17,343
Unrealized foreign exchange gain (loss)	**23,258**	(36,366)	8,625
Unrealized other expense	**(205)**	(204)	(195)
Accretion	**(7,986)**	(8,205)	(7,154)
Depletion and depreciation	**(177,029)**	(174,435)	(124,893)
Deferred tax	**(14,943)**	(64,084)	(9,651)
Gain on business combinations	**—**	128,208	—
Net earnings	**39,547**	323,373	24,740

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") and a security-based compensation arrangement ("Five-Year Compensation Arrangement").

Equity based compensation expense increased in Q1 2019 compared to Q4 2018 and Q1 2018, primarily due to the settlement of bonuses in Q1 2019 under the employee bonus plan.

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 months ended March 31, 2019, we recognized an unrealized loss on derivative instruments of $14.3 million. The unrealized loss primarily related to crude oil derivative instruments partially offset by unrealized gains on European natural gas derivative instruments.

Unrealized foreign exchange gains or losses

As a result of Vermilion's international operations, Vermilion has monetary assets and liabilities denominated in currencies other than the Canadian dollar. These monetary assets and liabilities include cash, receivables, payables, long-term debt, derivative instruments and intercompany loans. These monetary assets primarily relate to Euro denominated intercompany loans from Vermilion Energy Inc. to our international subsidiaries. These monetary liabilities primarily relate to our US$300.0 million senior unsecured notes.

Unrealized foreign exchange gains and losses result from translating these monetary assets and liabilities from their underlying currency to the Canadian dollar. Unrealized foreign exchange gains and losses primarily results from the translation of Euro denominated intercompany loans and US dollar denominated long-term debt. As such, an appreciation in the Euro against the Canadian dollar will result in an unrealized foreign exchange gain while an appreciation in the US dollar against the Canadian dollar will result in an unrealized foreign exchange loss (and vice-versa).

For the three months ended March 31, 2019, the impact of the Canadian dollar strengthening against the US dollar was more significant than the impact of the Canadian dollar strengthening against the Euro, resulting in an unrealized gain on foreign exchange of $23.3 million.

As at March 31, 2019, a $0.01 appreciation of the Euro against the Canadian dollar would result in a $2.2 million increase to net earnings as a result of an unrealized gain on foreign exchange. In contrast, a $0.01 appreciation of the US dollar against the Canadian dollar would result in a $3.4 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 Q1 2019 was relatively consistent with Q4 2018. For the three months ended March 31, 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 the three months ended March 31, 2019 of $18.68 was consistent with $18.67 in Q4 2018. Depletion and depreciation on a per boe basis for Q1 2019 of $18.68 was lower than the $20.07 per boe rate in Q1 2018, due to continued increases in our proved plus probable reserves.

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 months ended March 31, 2019, deferred tax expense of $14.9 million was primarily attributable to income earned in jurisdictions that do not incur current income taxes.

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 forecasted fund flows from operations is 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)	Mar 31, 2019	Dec 31, 2018
Long-term debt	**1,865,916**	1,796,207
Current liabilities	**459,182**	563,199
Current assets	**(324,954)**	(429,877)
Net debt	**2,000,144**	1,929,529
Ratio of net debt to quarterly annualized fund flows from operations	**1.97**	2.17

As at March 31, 2019, net debt increased to $2.00 billion (December 31, 2018 - $1.93 billion) primarily due to the impact of increased borrowings on the revolving credit facility to fund the capital expenditure program, which is heavily weighted towards Q1 2019, coupled with a $30.7 million decrease in net current derivative asset. These increases were more than offset by an increase in fund flows from operations, resulting in a decrease in the ratio of net debt to quarterly annualized fund flows from operations from 2.17 for 2018 to 1.97 for 2019.

Long-term debt

The balances recognized on our balance sheet are as follows:

	As at	
($M)	Mar 31, 2019	Dec 31, 2018
Revolving credit facility	**1,469,970**	1,392,206
Senior unsecured notes	**395,946**	404,001
Long-term debt	**1,865,916**	1,796,207

Revolving Credit Facility

In Q2 2019, we negotiated an extension to our $2.1 billion revolving credit facility to extend the maturity to May 31, 2023. The closing of the amendment is expected to take place before the end of April, 2019.

As at March 31, 2019, Vermilion had in place a bank revolving credit facility maturing May 31, 2022 with terms, outstanding positions, and covenants as follows:

($M)	As at Mar 31, 2019	Dec 31, 2018
Total facility amount	**2,100,000**	1,800,000
Amount drawn	**(1,469,970)**	(1,392,206)
Letters of credit outstanding	**(15,200)**	(15,400)
Unutilized capacity	**614,830**	392,394

As at March 31, 2019, the revolving credit facility was subject to the following covenants:

Financial covenant	Limit	As at Mar 31, 2019	Dec 31, 2018
Consolidated total debt to consolidated EBITDA	4.0	**1.74**	1.72
Consolidated total senior debt to consolidated EBITDA	3.5	**1.38**	1.34
Consolidated total senior debt to total capitalization	55%	**32%**	30%

Our 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 capitalization: Includes all amounts on our balance sheet classified as “Shareholders’ equity” plus consolidated total debt as defined above.

Senior Unsecured Notes

On March 13, 2017, Vermilion issued US$300 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%

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 in 2019 were $105.5 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.

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	**221**	**7,104**
Equity based compensation	**288**	**9,633**
Balance as at March 31, 2019	**153,213**	**4,025,565**

As at March 31, 2019, there were approximately 1.9 million equity based compensation awards outstanding. As at April 25, 2019, there were approximately 154.7 million common shares issued and outstanding.

Asset Retirement Obligations

As at March 31, 2019, asset retirement obligations were $719.7 million compared to $650.2 million as at December 31, 2018.

The increase in asset retirement obligations is largely attributable to 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 3.7% (2018 - 4.0%). The risk-free rates used as inputs to discount the obligations were as follows:

	Mar 31, 2019	Dec 31, 2018
Canada	**1.8%**	2.2%
France	**1.2%**	1.6%
Netherlands	**—%**	0.4%
Germany	**0.5%**	0.9%
Ireland	**1.1%**	1.6%
Australia	**2.0%**	2.6%
USA	**2.8%**	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 months ended March 31, 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 Spartan Energy Corp (which was acquired on May 28, 2018) and Shell 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 Spartan Energy Corp. and Shell E&P Ireland Limited included in Vermilion's financial statements as at and for the three months ended March 31, 2019:

($MM)	As at March 31, 2019
Non-current assets	1,517
Non-current liabilities	70
Net assets	1,397

($MM)	Three months ended March 31, 2019
Revenue	101
Net earnings	20

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 do 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 March 31, 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.

	Q1 2019			Q1 2018		
	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Liquids $/bbl	Natural Gas $/mcf	Total $/boe
Canada						
Sales	57.36	2.47	**39.87**	57.39	1.95	**32.19**
Royalties	(7.24)	(0.13)	**(4.59)**	(7.34)	(0.04)	**(3.41)**
Transportation	(2.52)	(0.18)	**(1.94)**	(2.38)	(0.15)	**(1.57)**
Operating	(13.30)	(1.49)	**(11.52)**	(8.94)	(1.31)	**(8.35)**
Operating netback	34.30	0.67	**21.82**	38.73	0.45	**18.86**
General and administration			**(0.49)**			**(0.24)**
Fund flows from operations netback			**21.33**			**18.62**
France						
Sales	81.52	1.76	**80.72**	81.70	—	**81.70**
Royalties	(11.14)	(0.01)	**(11.01)**	(10.60)	—	**(10.60)**
Transportation	(3.13)	—	**(3.09)**	(2.65)	—	**(2.65)**
Operating	(15.53)	—	**(15.36)**	(14.66)	—	**(14.66)**
Operating netback	51.72	1.75	**51.26**	53.79	—	**53.79**
General and administration			**(3.57)**			**(3.95)**
Current income taxes			**(7.52)**			**(2.31)**
Fund flows from operations netback			**40.17**			**47.53**
Netherlands						
Sales	67.10	8.63	**51.97**	68.64	8.86	**53.31**
Royalties	—	(0.13)	**(0.79)**	—	(0.21)	**(1.25)**
Operating	—	(1.79)	**(10.61)**	—	(1.91)	**(11.32)**
Operating netback	67.10	6.71	**40.57**	68.64	6.74	**40.74**
General and administration			**(1.14)**			**(1.14)**
Current income taxes			**(5.38)**			**(8.55)**
Fund flows from operations netback			**34.05**			**31.05**
Germany						
Sales	78.50	7.94	**56.09**	79.04	7.69	**56.86**
Royalties	(5.83)	(1.11)	**(6.44)**	(2.53)	(0.99)	**(4.82)**
Transportation	(10.86)	(0.43)	**(4.84)**	(9.80)	(0.58)	**(5.54)**
Operating	(27.52)	(2.20)	**(17.14)**	(22.08)	(2.46)	**(17.16)**
Operating netback	34.29	4.20	**27.67**	44.63	3.66	**29.34**
General and administration			**(5.54)**			**(4.32)**
Fund flows from operations netback			**22.13**			**25.02**
Ireland						
Sales	—	8.55	**51.30**	—	9.80	**58.79**
Transportation	—	(0.25)	**(1.50)**	—	(0.23)	**(1.41)**
Operating	—	(0.82)	**(4.91)**	—	(0.59)	**(3.51)**
Operating netback	—	7.48	**44.89**	—	8.98	**53.87**
General and administration			**(0.42)**			**(1.43)**
Fund flows from operations netback			**44.47**			**52.44**

	Q1 2019 Liquids $/bbl	Q1 2019 Natural Gas $/mcf	Q1 2019 Total $/boe	Q1 2018 Liquids $/bbl	Q1 2018 Natural Gas $/mcf	Q1 2018 Total $/boe
Australia						
Sales	91.02	—	**91.02**	86.94	—	**86.94**
Operating	(30.64)	—	**(30.64)**	(29.72)	—	**(29.72)**
PRRT [1]	(14.89)	—	**(14.89)**	(11.04)	—	**(11.04)**
Operating netback	45.49	—	**45.49**	46.18	—	**46.18**
General and administration			**(1.49)**			**(3.47)**
Corporate income taxes			**(5.30)**			**(1.53)**
Fund flows from operations netback			**38.70**			**41.18**
United States						
Sales	53.58	3.80	**45.31**	75.20	3.00	**72.94**
Royalties	(13.95)	(1.09)	**(11.96)**	(20.72)	(1.08)	**(20.16)**
Operating	(10.85)	(1.55)	**(10.44)**	(10.60)	—	**(10.18)**
Operating netback	28.78	1.16	**22.91**	43.88	1.92	**42.60**
General and administration			**(5.75)**			**(21.13)**
Fund flows from operations netback			**17.16**			**21.47**
Total Company						
Sales	66.62	5.10	**50.77**	71.03	5.81	**51.13**
Realized hedging (loss) gain	1.69	0.06	**1.09**	(3.24)	(0.42)	**(2.85)**
Royalties	(7.30)	(0.19)	**(4.58)**	(7.26)	(0.13)	**(3.69)**
Transportation	(2.33)	(0.17)	**(1.76)**	(2.35)	(0.17)	**(1.64)**
Operating	(16.13)	(1.47)	**(12.92)**	(14.57)	(1.32)	**(10.90)**
PRRT [1]	(1.96)	—	**(1.10)**	(1.73)	—	**(0.78)**
Operating netback	40.59	3.33	**31.50**	41.88	3.77	**31.27**
General and administration			**(1.38)**			**(1.88)**
Interest expense			**(2.21)**			**(2.50)**
Realized foreign exchange loss			**(0.22)**			**0.25**
Other income			**0.73**			**0.03**
Corporate income taxes			**(1.66)**			**(1.40)**
Fund flows from operations netback			**26.76**			**25.77**

(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 March 31, 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											
3-Way Collar	Sep 2018 - Jun 2019		CAD	2,500	91.20	2,500	98.63	2,500	76.00	—	—
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	—	1,350	91.76
3-Way Collar	Aug 2018 - Jun 2019		USD	500	66.92	500	80.00	500	55.00	—	—
3-Way Collar	Jan 2019 - Dec 2019		USD	500	70.00	500	80.00	500	60.00	—	—
3-Way Collar	Feb 2019 - Dec 2019		USD	1,000	59.55	1,000	67.50	1,000	52.50	—	—
Swap	Jul 2018 - Jun 2019		USD	—	—	—	—	—	—	1,500	68.52
Swap	Jan 2019 - Dec 2019		USD	—	—	—	—	—	—	2,250	73.17
WTI											
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	—	1,050	81.41
3-Way Collar	Jan 2019 - Dec 2019		USD	250	70.00	250	80.25	250	60.00	—	—
3-Way Collar	Feb 2019 - Jun 2019		USD	1,500	51.02	1,500	59.00	1,500	44.00	—	—
3-Way Collar	Feb 2019 - Dec 2019		USD	1,000	51.50	1,000	60.00	1,000	42.50	—	—
3-Way Collar	Oct 2019 - Mar 2020		USD	1,000	56.50	1,000	62.50	1,000	47.50	—	—
Swap	Apr 2019 - Mar 2020		USD	—	—	—	—	—	—	1,500	59.17
Swaption	Jul 2019 - Jun 2020	May 31, 2019	USD	—	—	—	—	—	—	500	61.00
Swaption	Jul 2019 - Jun 2020	June 28, 2019	USD	—	—	—	—	—	—	500	60.50

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 Basis (AECO less NYMEX Henry Hub)											
Swap	Jan 2019 - Jun 2020		USD	—	—	—	—	—	—	2,500	(0.93)
Swap	Apr 2019 - Oct 2019		USD	—	—	—	—	—	—	5,000	(1.61)

(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	Jan 2019 - Dec 2019		EUR	17,197	4.97	17,197	5.65	17,197	3.79	—	—
3-Way Collar	Jan 2019 - Dec 2020		EUR	7,370	4.96	7,370	5.76	7,370	3.74	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	19,654	5.10	19,654	5.92	19,654	4.01	—	—
3-Way Collar	Jan 2020 - Dec 2021		EUR	4,913	5.60	4,913	6.74	4,913	4.40	—	—
3-Way Collar	Jan 2021 - Dec 2021		EUR	4,913	5.72	4,913	6.45	4,913	4.69	—	—
Swap	Apr 2019 - Sep 2019		EUR	—	—	—	—	—	—	2,457	5.86
Swaption	Jul 2019 - Jun 2021	June 28, 2019	EUR	—	—	—	—	—	—	9,827	5.64
Swaption	Oct 2019 - Mar 2020	June 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86
Swaption	Jan 2020 - Mar 2020	Dec 31, 2019	EUR	—	—	—	—	—	—	2,047	7.33
Swaption	Oct 2020 - Mar 2021	June 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86
Swaption	Oct 2021 - Mar 2022	June 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86
NBP Basis (NBP less NYMEX Henry Hub)											
Collar	Jan 2019 - Sep 2020		USD	7,500	2.07	7,500	4.00	—	—	—	—
Collar	Jan 2020 - Dec 2020		USD	5,000	3.13	5,000	4.00	—	—	—	—
TTF											
3-Way Collar	Oct 2017 - Dec 2019		EUR	7,370	4.59	7,370	5.42	7,370	2.93	—	—
3-Way Collar	Jan 2018 - Dec 2019		EUR	3,685	4.74	3,685	5.52	3,685	3.13	—	—
3-Way Collar	Jan 2019 - Dec 2019		EUR	12,284	5.05	12,284	5.72	12,284	3.69	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—
Collar	Apr 2019 - Jun 2019		EUR	2,457	5.32	2,457	6.01	—	—	—	—
Collar	Jul 2019 - Sep 2019		EUR	1,228	5.35	1,228	6.01	—	—	—	—
Swap	Oct 2017 - Dec 2019		EUR	—	—	—	—	—	—	7,370	4.87
Swap	Jan 2018 - Dec 2019		EUR	—	—	—	—	—	—	1,228	5.00
Swap	Jul 2018 - Dec 2019		EUR	—	—	—	—	—	—	4,913	4.98
Swap	Jan 2019 - Dec 2019		EUR	—	—	—	—	—	—	2,457	4.92
Swap	Apr 2019 - Sep 2019		EUR	—	—	—	—	—	—	2,457	5.90

Cross Currency Interest Rate		Receive Notional Amount (USD)	Rate (LIBOR +)	Pay Notional Amount (CAD)	Rate (CDOR +)
Swap	Apr 2019	1,055,835,768	1.70%	1,404,900,000	1.37%

(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.

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Q1 2019	Q4 2018	Q1 2018
Drilling and development	**197,291**	160,359	124,658
Exploration and evaluation	**4,762**	3,221	3,807
Capital expenditures	**202,053**	163,580	128,465
Acquisitions	**16,027**	(31,314)	56,355
Contingent consideration	**—**	2	—
Long-term debt net of working capital assumed	**—**	34,005	36,723
Acquisitions	**16,027**	2,689	93,078

By category ($M)	Q1 2019	Q4 2018	Q1 2018
Drilling, completion, new well equip and tie-in, workovers and recompletions	**174,558**	151,511	108,893
Production equipment and facilities	**17,445**	9,166	16,142
Seismic, studies, land and other	**10,050**	2,903	3,430
Capital expenditures	**202,053**	163,580	128,465
Acquisitions	**16,027**	2,689	93,078
Total capital expenditures and acquisitions	**218,080**	166,269	221,543

Capital expenditures by country ($M)	Q1 2019	Q4 2018	Q1 2018
Canada	**128,055**	90,211	69,115
France	**22,086**	17,008	29,927
Netherlands	**6,349**	2,454	3,278
Germany	**3,044**	4,580	2,415
Ireland	**11**	140	47
Australia	**18,864**	43,760	4,449
United States	**20,036**	2,881	15,868
Corporate	**3,608**	2,546	3,366
Total capital expenditures	**202,053**	163,580	128,465

Acquisitions by country ($M)	Q1 2019	Q4 2018	Q1 2018
Canada	**14,660**	12,233	90,250
Netherlands	**908**	(7,860)	2,760
Germany	**416**	706	—
Ireland	**—**	(5,572)	—
United States	**43**	3,674	68
Corporate	**—**	(492)	—
Total acquisitions	**16,027**	2,689	93,078

In 2019, included in cash expenditures on acquisitions of $16.0 million is: $12.2 million net paid to vendors in relation to the purchase of assets from other oil and gas producers; $1.9 million in asset improvements incurred subsequent to acquisitions for compliance with safety, environmental, and Vermilion's operating standards; $0.6 million paid to acquire land; $0.9 million paid to acquire royalty interests, and $0.4 million relating to the carry component of farm-in arrangements.

Supplemental Table 4: Production

	Q1/19	Q4/18	Q3/18	Q2/18	Q1/18	Q4/17	Q3/17	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16
Canada												
Crude oil & condensate (bbls/d)	**29,164**	29,557	28,477	17,009	9,272	9,703	9,288	9,205	7,987	7,945	8,984	9,453
NGLs (bbls/d)	**6,968**	6,816	6,126	5,589	5,106	5,235	4,891	3,745	2,670	2,444	2,448	2,687
Natural gas (mmcf/d)	**151.37**	146.65	136.77	127.32	106.21	107.91	103.92	93.68	85.74	75.12	77.62	87.44
Total (boe/d)	**61,360**	60,814	57,397	43,817	32,078	32,923	31,499	28,563	24,947	22,910	24,368	26,713
% of consolidated	**59%**	60%	59%	55%	46%	45%	46%	43%	38%	38%	37%	42%
France												
Crude oil (bbls/d)	**11,342**	11,317	11,407	11,683	11,037	11,215	10,918	11,368	10,834	11,220	11,827	12,326
Natural gas (mmcf/d)	**0.77**	0.82	—	—	—	—	—	—	0.01	0.38	0.42	0.54
Total (boe/d)	**11,470**	11,454	11,407	11,683	11,037	11,215	10,918	11,368	10,836	11,283	11,897	12,416
% of consolidated	**11%**	11%	12%	14%	16%	15%	16%	17%	17%	19%	19%	19%
Netherlands												
Condensate (bbls/d)	**93**	112	84	87	77	105	74	104	76	57	86	96
Natural gas (mmcf/d)	**51.51**	51.82	44.37	43.49	44.79	55.66	34.90	31.58	39.92	41.15	47.62	49.18
Total (boe/d)	**8,677**	8,749	7,479	7,335	7,541	9,381	5,890	5,368	6,729	6,915	8,023	8,293
% of consolidated	**8%**	9%	8%	9%	11%	13%	9%	8%	10%	11%	13%	13%
Germany												
Crude oil (bbls/d)	**978**	913	1,019	1,008	1,078	1,148	1,054	1,047	989	—	—	—
Natural gas (mmcf/d)	**16.71**	16.94	14.88	14.63	16.19	18.19	20.12	19.86	19.39	14.80	14.52	14.31
Total (boe/d)	**3,763**	3,736	3,498	3,447	3,777	4,180	4,407	4,357	4,220	2,467	2,420	2,385
% of consolidated	**4%**	4%	4%	4%	5%	6%	7%	6%	7%	4%	4%	4%
Ireland												
Natural gas (mmcf/d)	**51.71**	52.03	51.38	56.56	60.87	56.23	49.04	63.81	64.82	62.92	59.28	47.26
Total (boe/d)	**8,619**	8,672	8,563	9,426	10,144	9,372	8,173	10,634	10,803	10,486	9,879	7,877
% of consolidated	**8%**	9%	9%	12%	14%	13%	12%	16%	17%	17%	16%	12%
Australia												
Crude oil (bbls/d)	**5,862**	4,174	4,704	4,132	4,971	4,993	5,473	6,054	6,581	6,388	6,562	6,083
% of consolidated	**6%**	4%	5%	5%	7%	7%	8%	9%	10%	10%	10%	9%
United States												
Crude oil (bbls/d)	**1,742**	1,605	1,461	655	574	667	880	747	365	362	383	458
NGLs (bbls/d)	**929**	998	714	62	20	43	56	76	24	23	30	26
Natural gas (mmcf/d)	**5.89**	5.65	4.82	0.40	0.15	0.29	0.64	0.44	0.20	0.18	0.20	0.20
Total (boe/d)	**3,653**	3,545	2,979	784	618	758	1,043	896	422	414	447	518
% of consolidated	**4%**	3%	3%	1%	1%	1%	2%	1%	1%	1%	1%	1%
Corporate												
Natural gas (mmcf/d)	**—**	2.86	1.17	—	—	—	—	—	—	—	—	—
Total (boe/d)	**—**	477	195	—	—	—	—	—	—	—	—	—
% of consolidated	**—**	—	—	—	—	—	—	—	—	—	—	—
Consolidated												
Liquids (bbls/d)	**57,078**	55,493	53,991	40,225	32,134	33,109	32,634	32,346	29,526	28,439	30,320	31,129
% of consolidated	**55%**	55%	56%	50%	46%	45%	48%	48%	46%	47%	48%	48%
Natural gas (mmcf/d)	**277.96**	276.77	253.38	242.40	228.20	238.28	208.62	209.36	210.07	194.54	199.65	198.93
% of consolidated	**45%**	45%	44%	50%	54%	55%	52%	52%	54%	53%	52%	52%
Total (boe/d)	**103,404**	101,621	96,222	80,625	70,167	72,821	67,403	67,240	64,537	60,863	63,596	64,285

	YTD 2019	2018	2017	2016	2015	2014
Canada						
Crude oil & condensate (bbls/d)	**29,164**	21,154	9,051	9,171	11,357	12,491
NGLs (bbls/d)	**6,968**	5,914	4,144	2,552	2,301	1,233
Natural gas (mmcf/d)	**151.37**	129.37	97.89	84.29	71.65	55.67
Total (boe/d)	**61,360**	48,630	29,510	25,771	25,598	23,001
% of consolidated	**59%**	56%	45%	40%	46%	47%
France						
Crude oil (bbls/d)	**11,342**	11,362	11,084	11,896	12,267	11,011
Natural gas (mmcf/d)	**0.77**	0.21	—	0.44	0.97	—
Total (boe/d)	**11,470**	11,396	11,085	11,970	12,429	11,011
% of consolidated	**11%**	13%	16%	19%	23%	22%
Netherlands						
Condensate (bbls/d)	**93**	90	90	88	99	77
Natural gas (mmcf/d)	**51.51**	46.13	40.54	47.82	44.76	38.20
Total (boe/d)	**8,677**	7,779	6,847	8,058	7,559	6,443
% of consolidated	**8%**	9%	10%	13%	14%	13%
Germany						
Crude oil (bbls/d)	**978**	1,004	1,060	—	—	—
Natural gas (mmcf/d)	**16.71**	15.66	19.39	14.90	15.78	14.99
Total (boe/d)	**3,763**	3,614	4,291	2,483	2,630	2,498
% of consolidated	**4%**	4%	6%	4%	5%	5%
Ireland						
Natural gas (mmcf/d)	**51.71**	55.17	58.43	50.89	0.03	—
Total (boe/d)	**8,619**	9,195	9,737	8,482	5	—
% of consolidated	**8%**	11%	14%	13%	—	—
Australia						
Crude oil (bbls/d)	**5,862**	4,494	5,770	6,304	6,454	6,571
% of consolidated	**6%**	5%	8%	10%	12%	13%
United States						
Crude oil (bbls/d)	**1,742**	1,078	666	393	231	49
NGLs (bbls/d)	**929**	452	50	29	7	—
Natural gas (mmcf/d)	**5.89**	2.78	0.39	0.21	0.05	—
Total (boe/d)	**3,653**	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)	**57,078**	45,548	31,915	30,433	32,716	31,432
% of consolidated	**55%**	52%	47%	48%	60%	63%
Natural gas (mmcf/d)	**277.96**	250.33	216.64	198.55	133.24	108.85
% of consolidated	**45%**	48%	53%	52%	40%	37%
Total (boe/d)	**103,404**	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 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 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 Condensed 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 Condensed 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 current period balance sheet and the previous year-end balance sheet.

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)	Q1 2019	Q4 2018	Q1 2018
Dividends declared	**105,549**	105,310	79,005
Shares issued for the Dividend Reinvestment Plan	**(7,104)**	(5,115)	(19,641)
Net dividends	**98,445**	100,195	59,364
Drilling and development	**197,291**	160,359	124,658
Exploration and evaluation	**4,762**	3,221	3,807
Asset retirement obligations settled	**3,597**	6,562	3,591
Payout	**304,095**	270,337	191,420
% of fund flows from operations	**120%**	122%	119%

('000s of shares)	Q1 2019	Q4 2018	Q1 2018
Shares outstanding	**153,213**	152,704	122,769
Potential shares issuable pursuant to the VIP	**3,437**	3,469	3,025
Diluted shares outstanding	**156,650**	156,173	125,794

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

	Twelve Months Ended	
($M)	Mar 31, 2019	Mar 31, 2018
Net earnings	**286,457**	42,458
Taxes	**100,928**	38,842
Interest expense	**78,150**	58,206
EBIT	**465,535**	139,506
Average capital employed	**4,824,945**	3,799,578
Return on capital employed	**10%**	4%

Consolidated Interim Financial Statements

Consolidated Balance Sheet

thousands of Canadian dollars, unaudited

	Note	March 31, 2019	December 31, 2018
Assets			
Current			
Cash and cash equivalents		**5,216**	26,809
Accounts receivable		**253,263**	260,322
Crude oil inventory		**16,962**	27,751
Derivative instruments		**32,200**	95,667
Prepaid expenses		**17,313**	19,328
Total current assets		**324,954**	429,877
Derivative instruments		**3,967**	1,215
Deferred taxes		**227,553**	219,411
Exploration and evaluation assets	5	**298,570**	303,295
Capital assets	4	**5,370,124**	5,316,873
Total assets		**6,225,168**	6,270,671
Liabilities			
Current			
Accounts payable and accrued liabilities		**357,570**	449,651
Dividends payable	8	**35,239**	35,122
Derivative instruments		**8,233**	41,016
Income taxes payable		**58,140**	37,410
Total current liabilities		**459,182**	563,199
Derivative instruments		**3,872**	17,527
Long-term debt	7	**1,865,916**	1,796,207
Lease obligations		**106,391**	108,189
Asset retirement obligations	6	**719,664**	650,164
Deferred taxes		**332,881**	318,134
Total liabilities		**3,487,906**	3,453,420
Shareholders' equity			
Shareholders' capital	8	**4,025,565**	4,008,828
Contributed surplus		**91,688**	78,478
Accumulated other comprehensive income		**74,248**	118,182
Deficit		**(1,454,239)**	(1,388,237)
Total shareholders' equity		**2,737,262**	2,817,251
Total liabilities and shareholders' equity		**6,225,168**	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 Earnings and Comprehensive (Loss) Income

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

	Note	Three Months Ended Mar 31, 2019	Mar 31, 2018
Revenue			
Petroleum and natural gas sales		**481,083**	318,269
Royalties		**(43,384)**	(22,995)
Sales of purchased commodities		**29,539**	—
Petroleum and natural gas revenue		**467,238**	295,274
Expenses			
Purchased commodities		**29,539**	—
Operating		**122,422**	67,839
Transportation		**16,700**	10,182
Equity based compensation		**22,843**	19,750
Loss on derivative instruments		**3,929**	372
Interest expense		**20,979**	15,588
General and administration		**13,058**	11,728
Foreign exchange gain		**(21,208)**	(10,179)
Other income		**(6,679)**	(6)
Accretion	6	**7,986**	7,154
Depletion and depreciation	4, 5	**177,029**	124,893
		386,598	247,321
Earnings before income taxes		**80,640**	47,953
Taxes			
Deferred		**14,943**	9,651
Current		**26,150**	13,562
		41,093	23,213
Net earnings		**39,547**	24,740
Other comprehensive (loss) income			
Currency translation adjustments		**(43,934)**	38,957
Comprehensive (loss) income		**(4,387)**	63,697
Net earnings per share			
Basic		**0.26**	0.20
Diluted		**0.26**	0.20
Weighted average shares outstanding ('000s)			
Basic		**152,904**	122,390
Diluted		**154,550**	124,304

Consolidated Statements of Cash Flows
thousands of Canadian dollars, unaudited

		Three Months Ended	
	Note	Mar 31, 2019	Mar 31, 2018
Operating			
Net earnings		**39,547**	24,740
Adjustments:			
Accretion	6	**7,986**	7,154
Depletion and depreciation	4, 5	**177,029**	124,893
Unrealized loss (gain) on derivative instruments		**14,277**	(17,343)
Equity based compensation		**22,843**	19,750
Unrealized foreign exchange gain		**(23,258)**	(8,625)
Unrealized other expense		**205**	195
Deferred taxes		**14,943**	9,651
Asset retirement obligations settled	6	**(3,597)**	(3,591)
Changes in non-cash operating working capital		**(45,747)**	17,794
Cash flows from operating activities		**204,228**	174,618
Investing			
Drilling and development	4	**(197,291)**	(124,658)
Exploration and evaluation	5	**(4,762)**	(3,807)
Acquisitions	4	**(16,027)**	(56,355)
Changes in non-cash investing working capital		**(2,885)**	20,847
Cash flows used in investing activities		**(220,965)**	(163,973)
Financing			
Borrowings on the revolving credit facility	7	**99,910**	23,909
Payments on lease obligations		**(6,468)**	(4,350)
Cash dividends		**(98,328)**	(59,225)
Cash flows used in financing activities		**(4,886)**	(39,666)
Foreign exchange gain on cash held in foreign currencies		**30**	1,759
Net change in cash and cash equivalents		**(21,593)**	(27,262)
Cash and cash equivalents, beginning of period		**26,809**	46,561
Cash and cash equivalents, end of period		**5,216**	19,299
Supplementary information for cash flows from operating activities			
Interest paid		**26,551**	18,134
Income taxes paid		**5,495**	342

Consolidated Statements of Changes in Shareholders' Equity

thousands of Canadian dollars, unaudited

	Three Months Ended	
	Mar 31, 2019	**Mar 31, 2018**
Shareholders' capital		
Balance, beginning of period	**4,008,828**	2,650,706
Shares issued for the Dividend Reinvestment Plan	**7,104**	19,641
Equity based compensation	**9,633**	7,444
Balance, end of period	**4,025,565**	2,677,791
Contributed surplus		
Balance, beginning of period	**78,478**	84,354
Equity based compensation	**13,210**	12,306
Balance, end of period	**91,688**	96,660
Accumulated other comprehensive income		
Balance, beginning of period	**118,182**	71,829
Currency translation adjustments	**(43,934)**	38,957
Balance, end of period	**74,248**	110,786
Deficit		
Balance, beginning of period	**(1,388,237)**	(1,264,003)
Net earnings	**39,547**	24,740
Dividends declared	**(105,549)**	(79,005)
Balance, end of period	**(1,454,239)**	(1,318,268)
Total shareholders' equity	**2,737,262**	1,566,969

Please refer to Note 8 (Shareholders' capital) for additional information.

Notes to the Condensed Consolidated Interim Financial Statements for the three months ended March 31, 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 Note 2, 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 April 25, 2019.

2. 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 do not result in changes to Vermilion's accounting policies for applying the acquisition method.

3. Segmented information

	Three Months Ended March 31, 2019								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Total assets	3,130,118	901,053	273,195	277,607	632,392	261,998	410,208	338,597	6,225,168
Drilling and development	128,055	22,084	6,330	1,877	11	18,864	20,036	34	197,291
Exploration and evaluation	—	2	19	1,167	—	—	—	3,574	4,762
Crude oil and condensate sales	172,659	82,581	559	7,431	—	63,582	10,774	—	337,586
NGL sales	13,874	—	—	—	—	—	2,109	—	15,983
Natural gas sales	33,623	121	40,027	11,937	39,792	—	2,014	—	127,514
Sales of purchased commodities	—	—	—	—	—	—	—	29,539	29,539
Royalties	(25,331)	(11,283)	(614)	(2,223)	—	—	(3,933)	—	(43,384)
Revenue from external customers	194,825	71,419	39,972	17,145	39,792	63,582	10,964	29,539	467,238
Purchased commodities	—	—	—	—	—	—	—	(29,539)	(29,539)
Transportation	(10,692)	(3,170)	—	(1,672)	(1,166)	—	—	—	(16,700)
Operating	(63,604)	(15,736)	(8,285)	(5,920)	(3,810)	(21,404)	(3,432)	(231)	(122,422)
General and administration	(2,719)	(3,655)	(892)	(1,913)	(329)	(1,039)	(1,891)	(620)	(13,058)
PRRT	—	—	—	—	—	(10,400)	—	—	(10,400)
Corporate income taxes	—	(7,700)	(4,200)	—	—	(3,700)	—	(150)	(15,750)
Interest expense	—	—	—	—	—	—	—	(20,979)	(20,979)
Realized gain on derivative instruments	—	—	—	—	—	—	—	10,348	10,348
Realized foreign exchange loss	—	—	—	—	—	—	—	(2,050)	(2,050)
Realized other income	—	—	—	—	—	—	—	6,884	6,884
Fund flows from operations	**117,810**	**41,158**	**26,595**	**7,640**	**34,487**	**27,039**	**5,641**	**(6,798)**	**253,572**

	Three Months Ended March 31, 2018								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Total assets	1,680,755	917,733	247,569	305,685	665,450	228,771	92,483	141,705	4,280,151
Drilling and development	69,115	29,893	3,245	1,954	47	4,449	15,868	87	124,658
Exploration and evaluation	—	34	33	461	—	—	—	3,279	3,807
Crude oil and condensate sales	62,623	72,745	475	9,299	—	38,170	3,953	—	187,265
NGL sales	11,639	—	—	—	—	—	66	—	11,705
Natural gas sales	18,671	—	35,711	11,202	53,675	—	40	—	119,299
Royalties	(9,848)	(9,438)	(850)	(1,737)	—	—	(1,122)	—	(22,995)
Revenue from external customers	83,085	63,307	35,336	18,764	53,675	38,170	2,937	—	295,274
Transportation	(4,540)	(2,358)	—	(1,998)	(1,286)	—	—	—	(10,182)
Operating	(24,096)	(13,049)	(7,685)	(6,186)	(3,209)	(13,048)	(566)	—	(67,839)
General and administration	(700)	(3,513)	(773)	(1,558)	(1,309)	(1,525)	(1,176)	(1,174)	(11,728)
PRRT	—	—	—	—	—	(4,848)	—	—	(4,848)
Corporate income taxes	—	(2,053)	(5,805)	—	—	(670)	—	(186)	(8,714)
Interest expense	—	—	—	—	—	—	—	(15,588)	(15,588)
Realized loss on derivative instruments	—	—	—	—	—	—	—	(17,715)	(17,715)
Realized foreign exchange gain	—	—	—	—	—	—	—	1,554	1,554
Realized other income	—	—	—	—	—	—	—	201	201
Fund flows from operations	**53,749**	**42,334**	**21,073**	**9,022**	**47,871**	**18,079**	**1,195**	**(32,908)**	**160,415**

Reconciliation of fund flows from operations to net earnings:

($M)	Three Months Ended Mar 31, 2019	Mar 31, 2018
Fund flows from operations	**253,572**	160,415
Accretion	**(7,986)**	(7,154)
Depletion and depreciation	**(177,029)**	(124,893)
Unrealized (loss) gain on derivative instruments	**(14,277)**	17,343
Equity based compensation	**(22,843)**	(19,750)
Unrealized foreign exchange gain	**23,258**	8,625
Unrealized other expense	**(205)**	(195)
Deferred tax	**(14,943)**	(9,651)
Net earnings	**39,547**	24,740

4. Capital assets

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

($M)	2019
Balance at January 1	**5,316,873**
Acquisitions	**16,027**
Additions	**197,291**
Increase in right-of-use assets	**6,850**
Transfers from exploration and evaluation assets	**1,039**
Depletion and depreciation	**(168,640)**
Changes in asset retirement obligations	**83,852**
Foreign exchange	**(83,168)**
Balance at March 31	**5,370,124**

5. Exploration and evaluation assets

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

($M)	2019
Balance at January 1	**303,295**
Additions	**4,762**
Changes in asset retirement obligations	**42**
Transfers to capital assets	**(1,039)**
Depreciation	**(4,586)**
Foreign exchange	**(3,904)**
Balance at March 31	**298,570**

6. Asset retirement obligations

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

($M)	2019
Balance at January 1	**650,164**
Additional obligations recognized	**4,914**
Obligations settled	**(3,597)**
Accretion	**7,986**
Changes in discount rates	**78,980**
Foreign exchange	**(18,783)**
Balance at March 31	**719,664**

7. Long-term debt

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

($M)	As at Mar 31, 2019	Dec 31, 2018
Revolving credit facility	**1,469,970**	1,392,206
Senior unsecured notes	**395,946**	404,001
Long-term debt	**1,865,916**	1,796,207

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

($M)	2019
Balance at January 1	**1,796,207**
Borrowings on the revolving credit facility	**99,910**
Amortization of transaction costs and prepaid interest	**2,823**
Foreign exchange	**(33,024)**
Balance at March 31	**1,865,916**

Revolving credit facility

At March 31, 2019, Vermilion had in place a bank revolving credit facility maturing May 31, 2022 with the following terms:

($M)	As at Mar 31, 2019	Dec 31, 2018
Total facility amount	**2,100,000**	1,800,000
Amount drawn	**(1,469,970)**	(1,392,206)
Letters of credit outstanding	**(15,200)**	(15,400)
Unutilized capacity	**614,830**	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 March 31, 2019, the revolving credit facility was subject to the following financial covenants:

Financial covenant	Limit	As at Mar 31, 2019	Dec 31, 2018
Consolidated total debt to consolidated EBITDA	4.0	**1.74**	1.72
Consolidated total senior debt to consolidated EBITDA	3.5	**1.38**	1.34
Consolidated total senior debt to total capitalization	55%	**32%**	30%

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.
- Total capitalization: Includes all amounts classified as "Shareholders' equity" plus consolidated total debt as defined above.

As at March 31, 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%

8. Shareholders' capital

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

	2019	
Shareholders' Capital	**Shares ('000s)**	**Amount ($M)**
Balance at January 1	**152,704**	**4,008,828**
Shares issued for the Dividend Reinvestment Plan	**221**	**7,104**
Shares issued for equity based compensation	**288**	**9,633**
Balance at March 31	**153,213**	**4,025,565**

Dividends declared to shareholders for the three months ended March 31, 2019 were $105.5 million (2018 - $79.0 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 $35.6 million or $0.23 per share.

9. 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 annualized fund flows from operations:

	Three Months Ended	
($M except as indicated)	**Mar 31, 2019**	**Mar 31, 2018**
Long-term debt	**1,865,916**	1,363,502
Current liabilities	**459,182**	396,247
Current assets	**(324,954)**	(234,187)
Net debt	**2,000,144**	1,525,562
Ratio of net debt to annualized fund flows from operations	**1.97**	2.38

10. 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.

($M)	Mar 31, 2019
Currency risk - Euro to Canadian dollar	
$0.01 increase in strength of the Canadian dollar against the Euro	**(2,200)**
$0.01 decrease in strength of the Canadian dollar against the Euro	**2,200**
Currency risk - US dollar to Canadian dollar	
$0.01 increase in strength of the Canadian dollar against the US $	**3,368**
$0.01 decrease in strength of the Canadian dollar against the US $	**(3,368)**
Commodity price risk - Crude oil	
US $5.00/bbl increase in crude oil price used to determine the fair value of derivatives	**(17,381)**
US $5.00/bbl decrease in crude oil price used to determine the fair value of derivatives	**18,862**
Commodity price risk - European natural gas	
€ 0.5/GJ increase in European natural gas price used to determine the fair value of derivatives	**(32,338)**
€ 0.5/GJ decrease in European natural gas price used to determine the fair value of derivatives	**29,213**

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 4, 6, 8]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Carin Knickel [6, 8, 12]
Golden, Colorado

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

Loren M. Leiker [10]
McKinney, Texas

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

Anthony Marino
Calgary, Alberta

Robert Michaleski [4, 5]
Calgary, Alberta

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

Catherine L. Williams [3, 6]
Calgary, Alberta

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

OFFICERS AND KEY PERSONNEL
CANADA

Anthony Marino
President & Chief Executive Officer

Lars Glemser
Vice President & Chief Financial Officer

Mona Jasinski
Executive Vice President, People and Culture

Michael Kaluza
Executive Vice President & Chief Operating Officer

Dion Hatcher
Vice President Canada Business Unit

Terry Hergott
Vice President Marketing

Jenson Tan
Vice President Business Development

Daniel Goulet
Director Corporate HSE

Jeremy Kalanuk
Director Operations Accounting

Bryce Kremnica
Director Field Operations - Canada Business Unit

Tom Rafter
Director Land - Canada Business Unit

Kyle Preston
Director Investor Relations

Robert (Bob) J. Engbloom
Corporate Secretary

UNITED STATES
Scott Seatter
Managing Director - U.S. Business Unit

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

EUROPE
Gerard Schut
Vice President European Operations

Sylvain Nothhelfer
Managing Director - France Business Unit

Sven Tummers
Managing Director - Netherlands Business Unit

Bill Liutkus
Managing Director - Germany Business Unit

Darcy Kerwin
Managing Director - Ireland Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUSTRALIA
Bruce D. Lake
Managing Director - Australia Business Unit

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Export Development Canada

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

Wells Fargo Bank N.A., Canadian Branch

HSBC Bank Canada

Bank of America N.A., Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Alberta Treasury Branches

Canadian Western Bank

Goldman Sachs Lending Partners LLC

Barclays Bank PLC

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TRANSFER AGENT

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

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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.

VERMILION
ENERGY

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