Q1 2020

MANAGEMENT'S DISCUSSION AND ANALYSIS

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.

INTERNATIONALLY DIVERSIFIED | SUSTAINABLE GROWTH AND INCOME

VERMILION ENERGY

Front Cover Theme

As illustrated by the front cover photo, we give together through our Days of Caring. Throughout the company, our staff volunteer to support social and environmental agencies we've partnered with in the communities where we operate.

Here, Vermilion has partnered with the Nature Conservancy of Canada (NCC), one of Canada's leading national conservation organizations. In 2016 and 2019, a group of Vermilion volunteers from our Canada Business Unit tackled projects like trail clearing and sign installation at the Coyote Lake Nature Sanctuary, which is a popular hiking destination near our operations in Drayton Valley, Alberta. This work helped to ensure a safe and enjoyable experience for visitors, and contributed to the safety of local wildlife.

NCC focuses on protecting the natural areas that sustain Canada's plants and wildlife by securing properties, and managing them for the long term. To date, NCC and its partners have helped to conserve more than 35 million acres of ecologically significant land from coast to coast.

Through programs like this, Vermilion is proud to have invested over $7.4 million and 10,800 hours of volunteer time in strategic community partnerships over the past five years.

Disclaimer

Certain statements included or incorporated by reference in this document may constitute forward looking statements or financial outlooks under applicable securities legislation. Such forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this document may include, but are not limited to: capital expenditures; business strategies and objectives; operational and financial performance; estimated reserve quantities and the discounted net present value of future net revenue from such reserves; petroleum and natural gas sales; future production levels (including the timing thereof) and rates of average annual production growth; exploration and development plans; acquisition and disposition plans and the timing thereof; operating and other expenses, including the payment and amount of future dividends; royalty and income tax rates; and the timing of regulatory proceedings and approvals.

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

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

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

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

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

Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated April 28, 2020, 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, 2020 compared with the corresponding periods in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three months ended March 31, 2020 and the audited consolidated financial statements for the years ended December 31, 2019 and 2018, 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, 2020 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with IAS 34, "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB").

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

- Fund flows from operations: Fund flows from operations is a measure of profit or loss in accordance with IFRS 8 "Operating Segments". Please see "Segmented Information" in the "Notes to the Condensed Consolidated Interim Financial Statements" for a reconciliation of fund flows from operations to net earnings. We analyze fund flows from operations both on a consolidated basis and on a business unit basis in order to assess the contribution of each business unit to our ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.
- Net debt: Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements". Net debt is comprised of long-term debt plus current liabilities less current assets and represents Vermilion's net financing obligations after adjusting for the timing of working capital fluctuations. Net debt excludes non-current lease obligations which are secured by a corresponding right-of-use asset. Please see "Capital disclosures" in the "Notes to the Condensed Consolidated Interim Financial Statements" for additional information.
- Netbacks: Netbacks are per boe and per mcf performance measures used in the analysis of operational activities. We assess netbacks both on a consolidated basis and on a business unit basis in order to compare and assess the operational and financial performance of each business unit versus other business units and also versus third party crude oil and natural gas producers.

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

Condensate Presentation

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

Guidance

On October 31, 2019, we released our 2020 capital budget and associated production guidance. On March 16, 2020, we announced a reduction of our 2020 capital budget and associated production guidance in response to a further decrease in oil prices as a result of the growing COVID-19 pandemic and the ensuing oil price war between OPEC+ members.

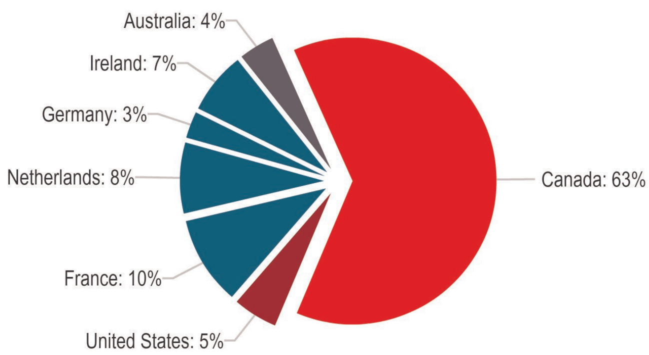
The following table summarizes our guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2020 Guidance			
2020 Guidance	October 31, 2019	450	100,000 to 103,000
2020 Guidance	March 16, 2020	350 to 370	94,000 to 98,000

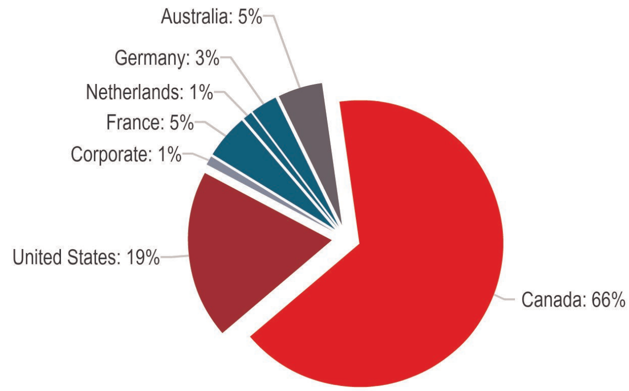
Vermilion's Business

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.

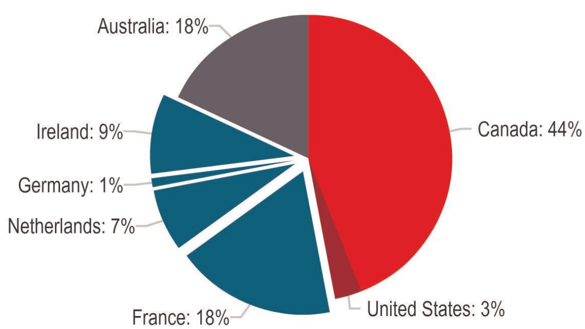
Q1 2020 production of 97,154 boe/d by business unit



Q1 2020 capital expenditures of $234MM by business unit



Q1 2020 fund flows from operations of $170MM by business unit

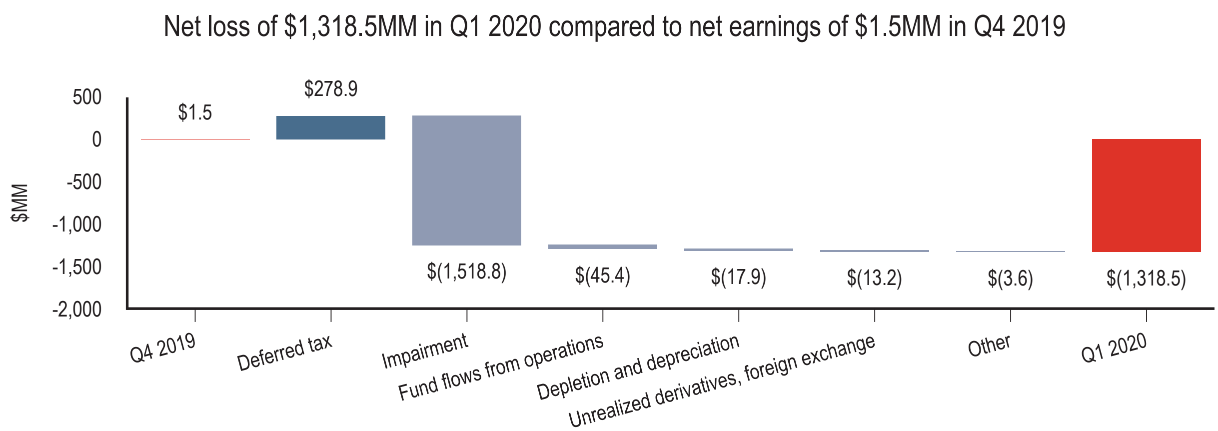


Consolidated Results Overview

	Q1 2020	Q4 2019	Q1 2019	Q1/20 vs. Q4/19	Q1/20 vs. Q1/19
Production					
Crude oil and condensate (bbls/d)	**44,881**	46,261	49,181	(3.0)%	(8.7)%
NGLs (bbls/d)	**8,022**	8,160	7,897	(1.7)%	1.6%
Natural gas (mmcf/d)	**265.51**	260.72	277.96	1.8%	(4.5)%
Total (boe/d)	**97,154**	97,875	103,404	(0.7)%	(6.0)%
Sales					
Crude oil and condensate (bbls/d)	**46,977**	44,423	51,068	5.7%	(8.0)%
NGLs (bbls/d)	**8,022**	8,160	7,897	(1.7)%	1.6%
Natural gas (mmcf/d)	**265.51**	260.72	277.96	1.8%	(4.5)%
Total (boe/d)	**99,250**	96,037	105,291	3.3%	(5.7)%
(Draw) build in inventory (mbbls)	**(191)**	169	(170)		
Financial metrics					
Fund flows from operations ($M)	**170,225**	215,592	253,572	(21.0)%	(32.9)%
Per share ($/basic share)	**1.09**	1.38	1.66	(21.0)%	(34.3)%
Net (loss) earnings ($M)	**(1,318,504)**	1,477	39,547	N/A	N/A
Per share ($/basic share)	**(8.42)**	0.01	0.26	N/A	N/A
Net debt ($M)	**2,155,623**	1,993,194	2,000,144	8.1%	7.8%
Cash dividends ($/share)	**0.575**	0.690	0.690	(16.7)%	(16.7)%
Activity					
Capital expenditures ($M)	**233,704**	100,625	202,053	132.3%	15.7%
Acquisitions ($M)	**11,337**	9,165	16,027		
Gross wells drilled	**87.00**	28.00	66.00		
Net wells drilled	**77.30**	17.25	62.94		

Financial performance review

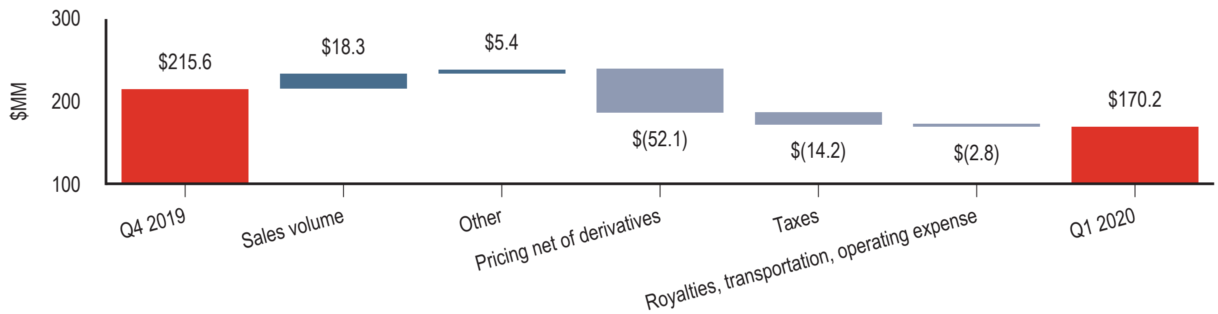
Q1 2020 vs. Q4 2019



"Other" contains equity based compensation and unrealized other

- We recorded a net loss in Q1 2020 of $1,318.5 million ($8.42/basic share) compared to net earnings of $1.5 million ($0.01/basic share) in Q4 2019. This quarter-over-quarter decrease was primarily driven by an increase in impairment charges of $1,518.8 million as a result of decreases in forecasted commodity prices, partially offset by deferred tax recoveries of $278.9 million. Impairment charges were incurred due to global commodity price forecasts deteriorating from decreases in demand as a result of the novel coronavirus ("COVID-19") and an increase of supply around the world as a result of the OPEC+ price war.

Fund flows from operations of $170.2MM in Q1 2020 compared to $215.6MM in Q4 2019

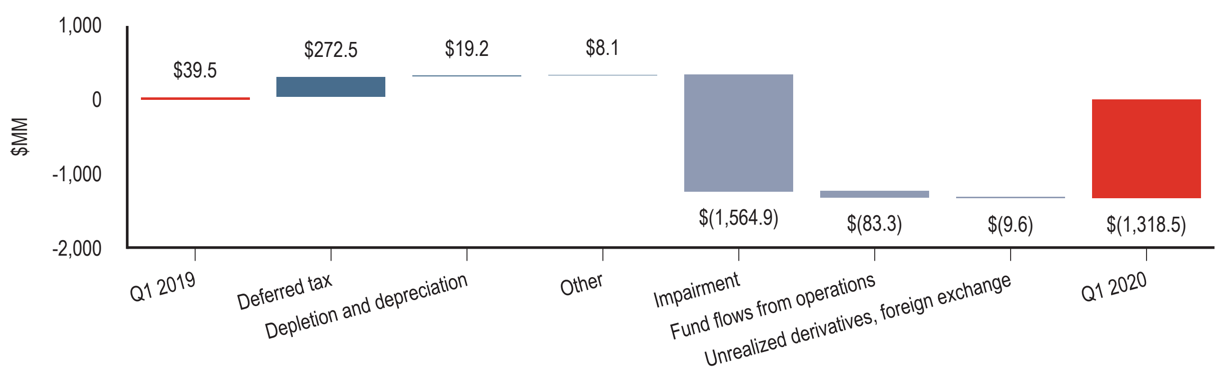


"Other" contains general and administration, interest, realized foreign exchange, and realized other

- Fund flows from operations of $170.2 million during Q1 2020 decreased versus Q4 2019 primarily driven by decreases in realized prices due to COVID-19 and OPEC+ price war, and higher cash taxes, partially offset by increased sales volumes as a result of increased Australian inventory draws during the current quarter.

Q1 2020 vs. Q1 2019

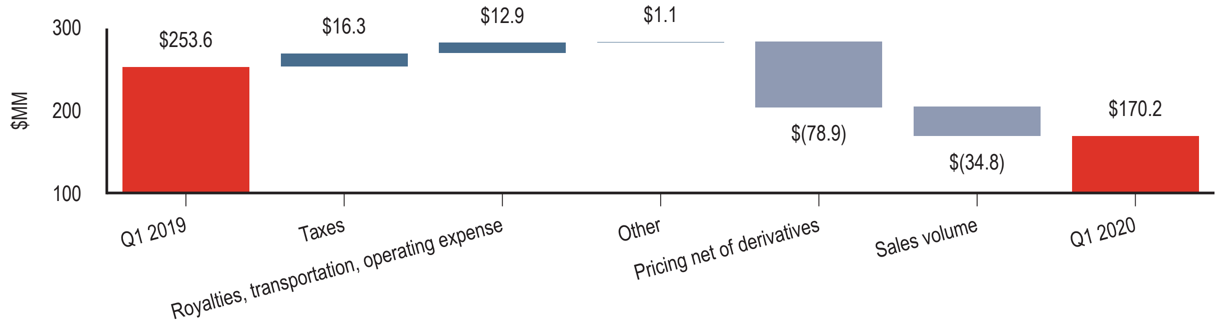
Net loss of $1,318.5MM in Q1 2020 compared to net earnings of $39.5MM in Q1 2019



"Other" contains equity based compensation and unrealized other

- We recorded a net loss for Q1 2020 of $1,318.5 million ($8.42/basic share) compared to net earnings of $39.5 million ($0.26/basic share) in Q1 2019. This change was primarily driven by impairment charges of $1,564.9 million in Q1 2020 as a result of decreases in forecasted commodity prices, partially offset by a decrease in deferred tax expense of $272.5 million. The decrease in net earnings also resulted from a decrease in fund flows from operations primarily as a result of lower realized prices due to COVID-19 and OPEC+ price war.

Fund flows from operations of $170.2MM in Q1 2020 compared to $253.6MM in Q1 2019



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

- We generated fund flows from operations of $170.2 million in Q1 2020, a decrease from $253.6 million in Q1 2019 primarily due to lower realized prices due to COVID-19 and OPEC+ dissolution, and lower sales volumes. Our consolidated realized price per boe decreased from $50.77/boe in Q1 2019 to $36.35/boe in Q1 2020.

Production review

Q1 2020 vs. Q4 2019

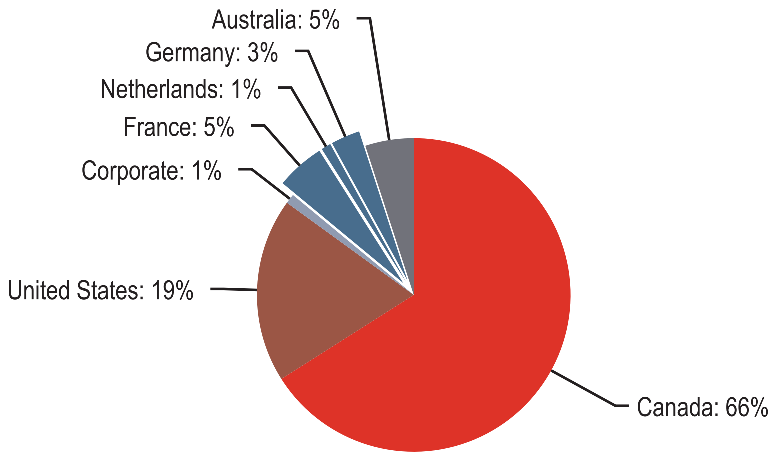
- Consolidated average production of 97,154 boe/d during Q1 2020 was down slightly compared to Q4 2019 production of 97,875 boe/d. Production increases are primarily in Canada from wells brought online in Q1 2020. These increases were offset by lower production primarily due to higher downtime in the United States and Australia, and minor impacts from COVID-19 on our operations.

Q1 2020 vs. Q1 2019

- Consolidated average production of 97,154 boe/d in Q1 2020 represented a decrease of 6% from Q1 2019 production of 103,404 boe/d. Production was lower due to natural decline, timing of completions and tie-ins from our Q1 2020 program and minor impacts from COVID-19. Production increased in the United States due to new wells brought online in 2019 and 2020.

Activity review

Q1 2020 capital expenditures of $233.7MM by business unit



- For the three months ended March 31, 2020, capital expenditures of $233.7 million were primarily related to activity in Canada and the United States. In Canada, capital expenditures of $152.6 million included the drilling of 77.0 (67.4 net) wells in Alberta and Saskatchewan. In the United States, capital expenditures of $45.3 million related to the drilling of 9.0 (8.9 net) wells. In Australia, capital expenditures of $12.0 million related to our workover program. In France, capital expenditures of $11.3 million related to workover, maintenance and facility costs in the Aquitaine and Paris Basins.

Sustainability review

Dividends

- On March 6, 2020, in response to weakness in commodity prices and reduced global economic prospects following the outbreak of COVID-19, Vermilion's board of directors approved a 50% reduction to the March dividend, payable April 15, 2020, to $0.115 per share. On April 15, due to further deterioration of economic prospects and commodity prices from COVID-19, the board of directors suspended the monthly dividend as a further measure to strengthen the financial position of the Company.
- Total dividends of $0.575 per common share were declared for the three months ended March 31, 2020.

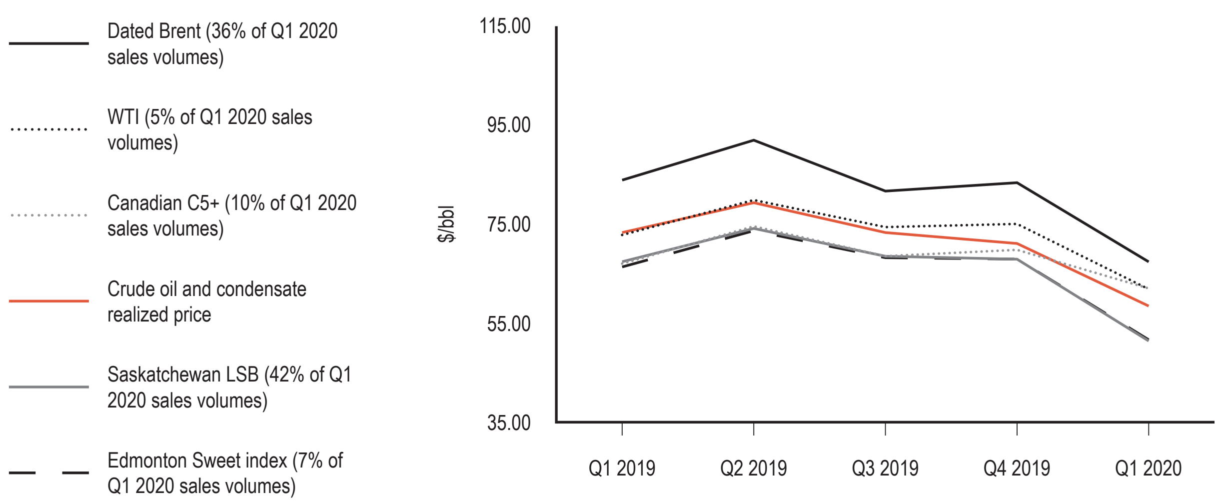
Long-term debt and net debt

- Long-term debt increased to $2.0 billion as at March 31, 2020 from $1.9 billion as at December 31, 2019. This increase was primarily a result of the impact of the weaker Canadian dollar on our USD borrowings from our revolving credit facility and our US denominated Senior Unsecured Notes.
- Net debt increased to $2.2 billion as at March 31, 2020, from $2.0 billion as at December 31, 2019, primarily due to an increase in accounts payable and accrued liabilities of $129.4 million resulting from increased capital activity.
- The ratio of net debt to four quarter trailing fund flows from operations increased to 2.61 as at March 31, 2020 (December 31, 2019 - 2.20) due to the increase in net debt combined with lower four quarter trailing fund flows from operations.

Benchmark Commodity Prices

	Q1 2020	Q4 2019	Q1 2019	Q1/20 vs. Q4/19	Q1/20 vs. Q1/19
Crude oil					
WTI ($/bbl)	**62.06**	75.19	72.97	(17.5)%	(15.0)%
WTI (US $/bbl)	**46.17**	56.96	54.90	(18.9)%	(15.9)%
Edmonton Sweet index ($/bbl)	**51.87**	68.10	66.53	(23.8)%	(22.0)%
Edmonton Sweet index (US $/bbl)	**38.59**	51.59	50.05	(25.2)%	(22.9)%
Saskatchewan LSB index ($/bbl)	**51.63**	68.09	67.58	(24.2)%	(23.6)%
Saskatchewan LSB index (US $/bbl)	**38.41**	51.58	50.84	(25.5)%	(24.4)%
Canadian C5+ Condensate index ($/bbl)	**62.21**	69.97	67.20	(11.1)%	(7.4)%
Canadian C5+ Condensate index (US $/bbl)	**46.28**	53.01	50.56	(12.7)%	(8.5)%
Dated Brent ($/bbl)	**67.56**	83.49	84.01	(19.1)%	(19.6)%
Dated Brent (US $/bbl)	**50.26**	63.25	63.20	(20.5)%	(20.5)%
Natural gas					
AECO ($/mcf)	**2.03**	2.48	2.62	(18.1)%	(22.5)%
NBP ($/mcf)	**4.32**	5.38	8.33	(19.7)%	(48.1)%
NBP (€/mcf)	**2.92**	3.68	5.52	(20.7)%	(47.1)%
TTF ($/mcf)	**4.23**	5.36	8.14	(21.1)%	(48.0)%
TTF (€/mcf)	**2.85**	3.67	5.39	(22.3)%	(47.1)%
Henry Hub ($/mcf)	**2.62**	3.30	4.19	(20.6)%	(37.5)%
Henry Hub (US $/mcf)	**1.95**	2.50	3.15	(22.0)%	(38.1)%
Average exchange rates					
CDN $/US $	**1.34**	1.32	1.33	1.5%	0.8%
CDN $/Euro	**1.48**	1.46	1.51	1.4%	(2.0)%
Realized prices					
Crude oil and condensate ($/bbl)	**58.66**	71.25	73.45	(17.7)%	(20.1)%
NGLs ($/bbl)	**8.92**	14.63	22.49	(39.0)%	(60.3)%
Natural gas ($/mcf)	**2.94**	3.61	5.10	(18.6)%	(42.4)%
Total ($/boe)	**36.35**	44.00	50.77	(17.4)%	(28.4)%

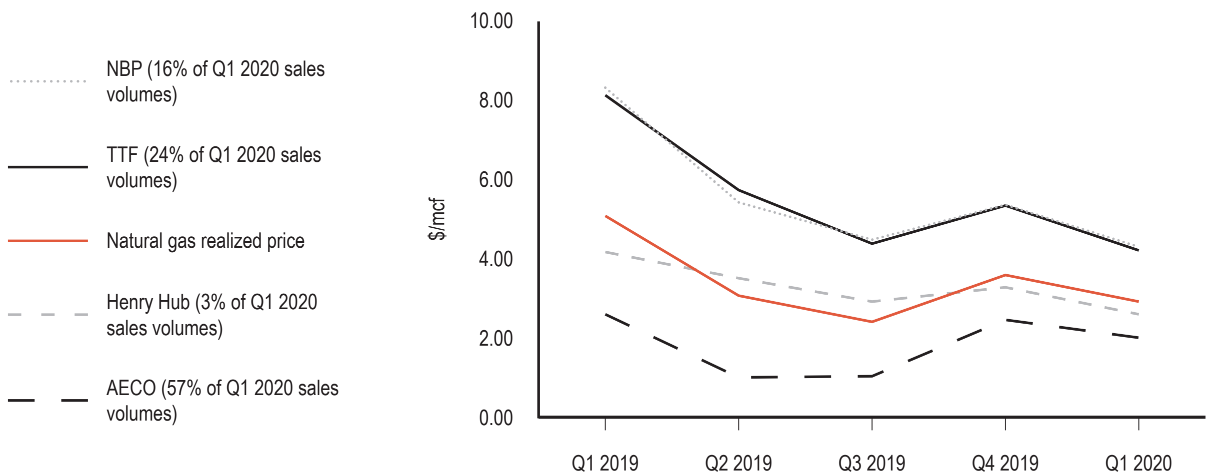
Q1 2020 realized crude oil and condensate price was a 13% premium to Edmonton Sweet Index



- Crude oil prices declined in Q1 2020 relative to Q4 2019 driven by oversupply from OPEC+ and global demand loss relating to COVID-19. By the end of Q1 2020, quarter-over-quarter WTI and Brent prices fell by 17.5% and 19.1% respectively, in Canadian dollar terms. For the three months ended March 31, 2020, WTI and Brent prices in Canadian dollar terms decreased by 15.0% and 19.6%, respectively, versus the comparable period in the prior year.

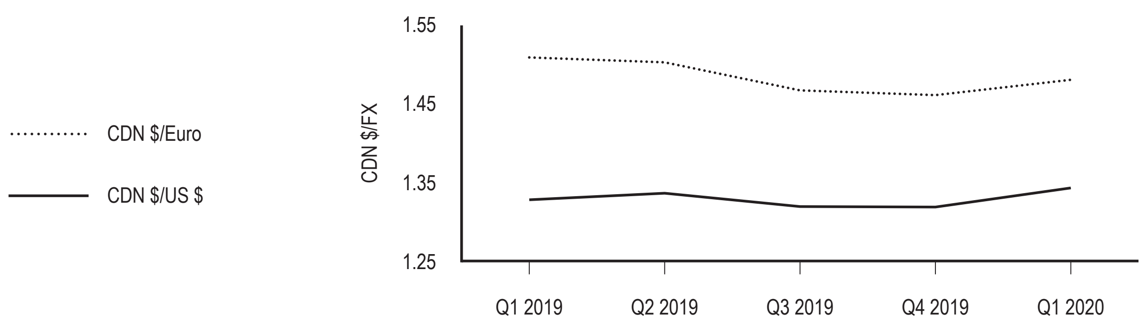
- In Canadian dollar terms, quarter-over-quarter, the Edmonton Sweet differential widened by $3.10/bbl to a discount of $10.19/bbl against WTI, and the Saskatchewan LSB differential widened by $3.33/bbl to a discount of $10.43/bbl against WTI. This was mainly driven by broad crude market weakness experienced by Canadian grades relative to WTI in January and February 2020.
- Vermilion's crude oil production benefits from light oil pricing and no exposure to significantly discounted heavy crude oil. Approximately 36% of our Q1 2020 crude oil and condensate production was priced at the Dated Brent index (which averaged a premium to WTI of US$4.09/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, Canadian C5+, and Wyoming light-oil historically had 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.

Q1 2020 realized natural gas price was a $0.91/mcf premium to AECO



- In Canadian dollar terms, market prices for European natural gas (TTF and NBP) decreased by 21.1% and 19.7%, respectively, in Q1 2020 compared to Q4 2019 due to a warmer than normal winter and abundant supply.
- Natural gas prices at AECO in Q1 2020 decreased by 18.1% compared to Q4 2019 due to broad weakness in North American natural gas prices.
- For Q1 2020, average European natural gas prices represented a $2.25/mcf premium to AECO and a $1.66/mcf premium to Henry Hub pricing. Approximately 40% of our natural gas production in Q1 2020 benefited from this premium European pricing. As a result, our consolidated natural gas realized price was a $0.91/mcf premium to AECO.

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



- For the three months ended March 31, 2020, the Canadian dollar weakened 1.5% against the US dollar quarter-over-quarter.
- For the three months ended March 31, 2020, the Canadian dollar weakened 1.4% against the Euro quarter-over-quarter.

Canada Business Unit

Overview

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

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

Operational and financial review

Canada business unit ($M except as indicated)	Q1 2020	Q4 2019	Q1 2019	Q1/20 vs. Q4/19	Q1/20 vs. Q1/19
Production and sales					
Crude oil and condensate (bbls/d)	**27,401**	27,399	29,164	—%	(6.0)%
NGLs (bbls/d)	**6,943**	7,005	6,968	(0.9)%	(0.4)%
Natural gas (mmcf/d)	**151.16**	145.14	151.37	4.1%	(0.1)%
Total (boe/d)	**59,537**	58,593	61,360	1.6%	(3.0)%
Production mix (% of total)					
Crude oil and condensate	**46%**	47%	48%		
NGLs	**12%**	12%	11%		
Natural gas	**42%**	41%	41%		
Activity					
Capital expenditures	**152,577**	66,643	128,055	128.9%	19.1%
Acquisitions	**5,439**	5,003	14,660		
Gross wells drilled	**77.00**	26.00	58.00		
Net wells drilled	**67.40**	16.74	54.94		
Financial results					
Sales	**154,963**	206,897	220,156	(25.1)%	(29.6)%
Royalties	**(16,685)**	(24,127)	(25,331)	(30.8)%	(34.1)%
Transportation	**(11,138)**	(10,384)	(10,692)	7.3%	4.2%
Operating	**(64,185)**	(60,931)	(63,604)	5.3%	0.9%
General and administration	**(2,843)**	(7,424)	(2,719)	(61.7)%	4.6%
Fund flows from operations	**60,112**	104,031	117,810	(42.2)%	(49.0)%
Netbacks ($/boe)					
Sales	**28.60**	38.38	39.87	(25.5)%	(28.3)%
Royalties	**(3.08)**	(4.48)	(4.59)	(31.3)%	(32.9)%
Transportation	**(2.06)**	(1.93)	(1.94)	6.7%	6.2%
Operating	**(11.85)**	(11.30)	(11.52)	4.9%	2.9%
General and administration	**(0.52)**	(1.38)	(0.49)	(62.3)%	6.1%
Fund flows from operations netback	**11.09**	19.29	21.33	(42.5)%	(48.0)%
Realized prices					
Crude oil and condensate ($/bbl)	**50.06**	66.27	65.47	(24.5)%	(23.5)%
NGLs ($/bbl)	**6.98**	13.63	22.12	(48.8)%	(68.4)%
Natural gas ($/mcf)	**1.90**	2.33	2.47	(18.5)%	(23.1)%
Total ($/boe)	**28.60**	38.38	39.87	(25.5)%	(28.3)%
Reference prices					
WTI (US $/bbl)	**46.17**	56.96	54.90	(18.9)%	(15.9)%
Edmonton Sweet index ($/bbl)	**51.87**	68.10	66.53	(23.8)%	(22.0)%
Saskatchewan LSB index ($/bbl)	**51.63**	68.09	67.58	(24.2)%	(23.6)%
Canadian C5+ Condensate index ($/bbl)	**62.21**	69.97	67.20	(11.1)%	(7.4)%
AECO ($/mcf)	**2.03**	2.48	2.62	(18.1)%	(22.5)%

Production

- Q1 2020 production increased 2% from the prior quarter primarily due to production contributions from new well completions partially offset by natural decline. Quarterly production decreased 3% year-over-year primarily due to natural decline and reduced drilling activity in the respective preceding quarters.

Activity

Vermilion drilled 70 (66.9 net) operated wells and participated in the drilling of seven (0.5 net) non-operated wells in Canada during Q1 2020.

Alberta

– In Q1 2020, we drilled 15 (15.0 net) operated wells, completed 17 (17.0 net) operated wells, and brought on production 13 (13.0 net) operated wells in Alberta.

Saskatchewan

– In Q1 2020, we drilled 55 (51.9 net) operated wells and participated in the drilling of seven (0.5 net) non-operated wells, completed 56 (52.9 net) operated wells and five (0.3 net) non-operated wells, and brought 51 (47.8 net) operated wells and four (0.2 net) non-operated wells on production in Saskatchewan.

Sales

- The realized price for our crude oil and condensate production in Canada is linked to WTI and is subject to market conditions in western Canada as reflected by the Saskatchewan LSB, Canadian Condensate C5+, and Edmonton Sweet index prices. The realized price of our natural gas in Canada is based on the AECO index.
- Sales decreased in Q1 2020 compared to Q4 2019 and Q1 2019 by 25.1% and 29.6%, respectively, primarily due to lower realized prices as production remained relatively consistent. Quarter-over-quarter, our crude oil and condensate production mix remained stable at approximately 50% of production.

Royalties

- Q1 2020 royalties as a percentage of sales of 10.8% decreased from 11.7% in Q4 2019 and from 11.5% in Q1 2019. This decrease is primarily due to the effect of lower commodity prices on sliding scale royalties coupled with lower average royalty rates for new wells brought on production.

Transportation

- Q1 2020 transportation expense on a dollar and per unit basis remained consistent with Q4 2019 and Q1 2019.

Operating

- Q1 2020 operating expense on a dollar and per unit basis increased compared to Q4 2019 and Q1 2019 primarily due to weather related increases in electricity and well repair costs.

General and administration

- General and administrative expenses decreased from Q4 2019 to Q1 2020 primarily due to an increase in allocations from our Corporate segment and increased headcount costs in the prior quarter combined with higher recoveries in the current quarter.

France Business Unit

Overview

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

Operational and financial review

France business unit ($M except as indicated)	Q1 2020	Q4 2019	Q1 2019	Q1/20 vs. Q4/19	Q1/20 vs. Q1/19
Production					
Crude oil (bbls/d)	**9,957**	10,264	11,342	(3.0)%	(12.2)%
Natural gas (mmcf/d)	**—**	—	0.77	—%	—%
Total (boe/d)	**9,957**	10,264	11,470	(3.0)%	(13.2)%
Sales					
Crude oil (bbls/d)	**10,217**	10,454	11,256	(2.3)%	(9.2)%
Natural gas (mmcf/d)	**—**	—	0.77	—%	—%
Total (boe/d)	**10,217**	10,454	11,384	(2.3)%	(10.3)%
Inventory (mbbls)					
Opening crude oil inventory	**209**	227	325		
Crude oil production	**906**	944	1,021		
Crude oil sales	**(930)**	(962)	(1,014)		
Closing crude oil inventory	**185**	209	332		
Activity					
Capital expenditures	**11,257**	8,745	22,086	28.7%	(49.0)%
Gross wells drilled	**—**	—	3.00		
Net wells drilled	**—**	—	3.00		
Financial results					
Sales	**56,789**	77,781	82,702	(27.0)%	(31.3)%
Royalties	**(9,040)**	(10,265)	(11,283)	(11.9)%	(19.9)%
Transportation	**(3,725)**	(3,215)	(3,170)	15.9%	17.5%
Operating	**(15,899)**	(16,142)	(15,736)	(1.5)%	1.0%
General and administration	**(3,448)**	(4,821)	(3,655)	(28.5)%	(5.7)%
Current income taxes	**—**	(4,966)	(7,700)	(100.0)%	(100.0)%
Fund flows from operations	**24,677**	38,372	41,158	(35.7)%	(40.0)%
Netbacks ($/boe)					
Sales	**61.08**	80.87	80.72	(24.5)%	(24.3)%
Royalties	**(9.72)**	(10.67)	(11.01)	(8.9)%	(11.7)%
Transportation	**(4.01)**	(3.34)	(3.09)	20.1%	29.8%
Operating	**(17.10)**	(16.78)	(15.36)	1.9%	11.3%
General and administration	**(3.71)**	(5.01)	(3.57)	(25.9)%	3.9%
Current income taxes	**—**	(5.16)	(7.52)	(100.0)%	(100.0)%
Fund flows from operations netback	**26.54**	39.91	40.17	(33.5)%	(33.9)%
Reference prices					
Dated Brent (US $/bbl)	**50.26**	63.25	63.20	(20.5)%	(20.5)%
Dated Brent ($/bbl)	**67.56**	83.49	84.01	(19.1)%	(19.6)%

Production

- Q1 2020 production decreased 3% from the prior quarter primarily due to higher than normal well downtime. The COVID-19 confinement measures put in place by the France government in mid-March restricted our ability to complete well workovers and facility maintenance. In addition, the Total-operated Grandpuits refinery temporarily shut down operations in late March due to low product demand induced by COVID-19. Quarterly production decreased 13% year-over-year due to natural decline.

Activity

- During Q1 2020, we continued our workover and optimization programs in the Aquitaine and Paris Basins.

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Q1 2020 sales decreased versus Q4 2019 primarily due to a decrease in realized prices.
- Q1 2020 sales decreased versus Q1 2019 due to a decrease in realized prices coupled with natural decline.

Royalties

- Royalties in France relate to two components: RCDM (levied on units of production and not subject to changes in commodity prices) and R31 (based on a percentage of sales).
- For the three months ended March 31, 2020, royalties decreased versus the comparable periods due to lower R31 royalties on lower sales combined with lower RCDM royalties on lower production.
- Royalties as a percentage of sales of 15.9% in Q1 2020 increased compared to 13.2% and 13.6% in Q4 2019 and Q1 2019 respectively. This relative increase was due to RCDM royalties which were not impacted by lower Dated Brent reference pricing.

Transportation

- Transportation expense increased in Q1 2020 versus the comparable periods due to the timing of maintenance work performed on our transportation infrastructure as well as increased trucking costs related to pipeline downtime.

Operating

- Operating expense in Q1 2020 remained consistent with Q4 2019 on both a dollar and per unit basis.
- Operating expense in Q1 2020 remained consistent with Q1 2019 on a dollar basis. On a per unit basis, operating expense increased year-over-year due to the timing of project work.

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 28.9%.
- 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 2020, there are no expected current income taxes to be reported. 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 28, 2019, the French Parliament approved the Finance Bill for 2020. The Finance Bill for 2020 provides for a progressive decrease of the French corporate income tax rate for companies with sales below €250 million from 28.9% in 2020 to 25.8% by 2022.

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 ($M except as indicated)	Q1 2020	Q4 2019	Q1 2019	Q1/20 vs. Q4/19	Q1/20 vs. Q1/19
Production and sales					
Condensate (bbls/d)	**87**	90	93	(3.3)%	(6.5)%
Natural gas (mmcf/d)	**48.33**	47.99	51.51	0.7%	(6.2)%
Total (boe/d)	**8,143**	8,088	8,677	0.7%	(6.2)%
Activity					
Capital expenditures	**2,497**	9,651	6,349	(74.1)%	(60.7)%
Acquisitions	**—**	—	908		
Gross wells drilled	**—**	2.00	—		
Net wells drilled	**—**	0.51	—		
Financial results					
Sales	**19,603**	25,215	40,586	(22.3)%	(51.7)%
Royalties	**(143)**	(130)	(614)	10.0%	(76.7)%
Operating	**(8,915)**	(9,758)	(8,285)	(8.6)%	7.6%
General and administration	**(555)**	(763)	(892)	(27.3)%	(37.8)%
Current income taxes	**—**	11,198	(4,200)	(100.0)%	(100.0)%
Fund flows from operations	**9,990**	25,762	26,595	(61.2)%	(62.4)%
Netbacks ($/boe)					
Sales	**26.45**	33.88	51.97	(21.9)%	(49.1)%
Royalties	**(0.19)**	(0.17)	(0.79)	11.8%	(75.9)%
Operating	**(12.03)**	(13.11)	(10.61)	(8.2)%	13.4%
General and administration	**(0.75)**	(1.03)	(1.14)	(27.2)%	(34.2)%
Current income taxes	**—**	15.05	(5.38)	(100.0)%	(100.0)%
Fund flows from operations netback	**13.48**	34.62	34.05	(61.1)%	(60.4)%
Realized prices					
Condensate ($/bbl)	**64.32**	73.51	67.10	(12.5)%	(4.1)%
Natural gas ($/mcf)	**4.34**	5.57	8.63	(22.1)%	(49.7)%
Total ($/boe)	**26.45**	33.88	51.97	(21.9)%	(49.1)%
Reference prices					
TTF ($/mcf)	**4.23**	5.36	8.14	(21.1)%	(48.0)%
TTF (€/mcf)	**2.85**	3.67	5.39	(22.3)%	(47.1)%

Production

- Q1 2020 production increased 1% from the prior quarter due to higher uptime across our asset base, partially offset by natural decline. Quarterly production decreased 6% year-over-year primarily due to natural decline.

Activity

- During Q1 2020, we flowed the Weststellingwerf well (0.5 net) as we await receipt of the final production permit, while also advancing permitting for future planned wells.

Sales

- The price of our natural gas in the Netherlands is based on the TTF index.
- Q1 2020 sales decreased compared to Q4 2019 due to lower realized pricing, partially offset by an increase in production volumes.
- Q1 2020 sales decreased compared to Q1 2019 due to lower realized pricing combined with lower production volumes due to natural decline.

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 Q1 2020 remained consistent compared to Q4 2019.
- Royalties in Q1 2020 represented 0.7% of sales, a decrease from 1.5% in Q1 2019 due to the acquisition of certain royalty rights with an effective date of March 1, 2019 which resulted in lower royalty rates in subsequent periods.

Transportation

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

Operating

- Operating expense on a dollar and per unit basis decreased in Q1 2020 compared to Q4 2019 primarily as a result of reduced maintenance activity.
- Operating expense on a dollar and per unit basis increased in Q1 2020 compared to Q1 2019 primarily as a result of the timing of activity.

General and administration

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

Current income taxes

- In the Netherlands, current income taxes are applied to taxable income, after eligible deductions and a 10% uplift deduction applied to operating expenses, eligible general and administration expenses, and tax deductions for depletion and asset retirement obligations, at a tax rate of 50%.
- Full year effective tax rates are estimated each quarter based on forecasted commodity prices and operational results. The estimated full year effective tax rate is applied on a pro-rata basis to quarterly results. As such, fluctuations between the reporting periods occur due to changes in estimated tax rates.
- For 2020, there are no expected current income taxes to be reported. 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 17, 2019, the Dutch government approved the 2020 Tax Plan. The Bill provides for reduced corporate tax rates from 25.0% in 2020 to 21.7% by 2021. 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 on 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 1.1 million net acres (97% undeveloped).

Operational and financial review

Germany business unit ($M except as indicated)	Q1 2020	Q4 2019	Q1 2019	Q1/20 vs. Q4/19	Q1/20 vs. Q1/19
Production					
Crude oil (bbls/d)	**909**	800	978	13.6%	(7.1)%
Natural gas (mmcf/d)	**14.64**	15.44	16.71	(5.2)%	(12.4)%
Total (boe/d)	**3,349**	3,373	3,763	(0.7)%	(11.0)%
Sales					
Crude oil (bbls/d)	**875**	629	1,052	39.1%	(16.8)%
Natural gas (mmcf/d)	**14.64**	15.44	16.71	(5.2)%	(12.4)%
Total (boe/d)	**3,315**	3,202	3,837	3.5%	(13.6)%
Production mix (% of total)					
Crude oil	**27%**	24%	26%		
Natural gas	**73%**	76%	74%		
Activity					
Capital expenditures	**7,789**	5,177	3,044	50.5%	155.9%
Acquisitions	**19**	1,456	416		
Financial results					
Sales	**10,469**	11,531	19,368	(9.2)%	(45.9)%
Royalties	**(942)**	(587)	(2,223)	60.5%	(57.6)%
Transportation	**(1,322)**	(963)	(1,672)	37.3%	(20.9)%
Operating	**(4,915)**	(7,405)	(5,920)	(33.6)%	(17.0)%
General and administration	**(1,741)**	(1,957)	(1,913)	(11.0)%	(9.0)%
Fund flows from operations	**1,549**	619	7,640	150.2%	(79.7)%
Netbacks ($/boe)					
Sales	**34.70**	39.14	56.09	(11.3)%	(38.1)%
Royalties	**(3.12)**	(1.99)	(6.44)	56.8%	(51.6)%
Transportation	**(4.38)**	(3.27)	(4.84)	33.9%	(9.5)%
Operating	**(16.29)**	(25.14)	(17.14)	(35.2)%	(5.0)%
General and administration	**(5.77)**	(6.64)	(5.54)	(13.1)%	4.2%
Fund flows from operations netback	**5.14**	2.10	22.13	144.8%	(76.8)%
Realized prices					
Crude oil ($/bbl)	**59.72**	77.58	78.50	(23.0)%	(23.9)%
Natural gas ($/mcf)	**4.29**	4.96	7.94	(13.5)%	(46.0)%
Total ($/boe)	**34.70**	39.14	56.09	(11.3)%	(38.1)%
Reference prices					
Dated Brent (US $/bbl)	**50.26**	63.25	63.20	(20.5)%	(20.5)%
Dated Brent ($/bbl)	**67.56**	83.49	84.01	(19.1)%	(19.6)%
TTF ($/mcf)	**4.23**	5.36	8.14	(21.1)%	(48.0)%
TTF (€/mcf)	**2.85**	3.67	5.39	(22.3)%	(47.1)%

Production

- Q1 2020 production decreased 1% from the prior quarter primarily due to planned downtime to perform various workovers and facility maintenance, which was partially offset by improved uptime at one of our operated oil fields following the completion of pipeline maintenance. Quarterly production decreased 11% year-over-year due to planned and unplanned downtime, along with natural decline on our operated and non-operated oil and natural gas assets.

Activity

- During Q1 2020, we performed various workovers on our operated assets. As previously reported, we expect production from the Burgmoor Z5 (46% working interest) well, which was tested early in the third quarter of 2019, to begin early next year.

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.
- Q1 2020 sales decreased compared to Q4 2019 due to lower realized crude oil and natural gas prices, partially offset by an increase in production volumes.
- Q1 2020 sales decreased compared to Q1 2019 due to lower realized crude oil and natural gas prices combined with lower production volumes due to downtime on our assets.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Royalties as a percentage of sales increased quarter-over-quarter due to a favourable prior period adjustment recorded in Q4 2019.
- Royalties as a percentage of sales decreased year-over-year due to an unfavourable prior period adjustment recorded in Q1 2019.

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 increased quarter-over-quarter due to higher production in the current quarter and favourable prior period adjustments recorded in Q4 2019.
- Transportation expense decreased year-over-year primarily due to lower production in the current quarter.

Operating

- Q1 2020 operating expense decreased versus Q4 2019 and Q1 2019 primarily due to the timing of activity on non-operated assets.

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 2020 in the Germany Business Unit. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.

Ireland Business Unit

Overview

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

Operational and financial review

Ireland business unit ($M except as indicated)	Q1 2020	Q4 2019	Q1 2019	Q1/20 vs. Q4/19	Q1/20 vs. Q1/19
Production and sales					
Natural gas (mmcf/d)	**41.38**	42.30	51.71	(2.2)%	(20.0)%
Total (boe/d)	**6,896**	7,049	8,619	(2.2)%	(20.0)%
Activity					
Capital expenditures	**(20)**	923	11	N/A	N/A
Acquisitions	**—**	—	—		
Financial results					
Sales	**17,588**	21,824	39,792	(19.4)%	(55.8)%
Transportation	**(1,145)**	(1,008)	(1,166)	13.6%	(1.8)%
Operating	**(4,212)**	(2,854)	(3,810)	47.6%	10.6%
General and administration	**(390)**	(484)	(329)	(19.4)%	18.5%
Fund flows from operations	**11,841**	17,478	34,487	(32.3)%	(65.7)%
Netbacks ($/boe)					
Sales	**28.03**	33.65	51.30	(16.7)%	(45.4)%
Transportation	**(1.82)**	(1.55)	(1.50)	17.4%	21.3%
Operating	**(6.71)**	(4.40)	(4.91)	52.5%	36.7%
General and administration	**(0.62)**	(0.75)	(0.42)	(17.3)%	47.6%
Fund flows from operations netback	**18.88**	26.95	44.47	(29.9)%	(57.5)%
Reference prices					
NBP ($/mcf)	**4.32**	5.38	8.33	(19.7)%	(48.1)%
NBP (€/mcf)	**2.92**	3.68	5.52	(20.7)%	(47.1)%

Production

- Q1 2020 production decreased 2% from the prior quarter primarily due to natural decline, partially offset by higher uptime at the Corrib natural gas processing facility compared to the prior quarter. Quarterly production decreased 20% year-over-year due to natural decline.

Activity

- Our 2020 capital program is focused on turnarounds and optimization opportunities at the Corrib natural gas processing facility.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Sales for the three months ended March 31, 2020 decreased versus the comparable periods primarily due to decreases in realized prices and natural decline of production volumes.

Royalties

- Our production in Ireland is not subject to royalties.

Transportation

- Transportation expense in Ireland relates to payments under a ship-or-pay agreement.
- Transportation expense for Q1 2020 remained relatively consistent with versus the comparable periods.

Operating

- Operating expense increased quarter-over-quarter and year-over-year primarily due to the timing of expenditures.

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 ($M except as indicated)	Q1 2020	Q4 2019	Q1 2019	Q1/20 vs. Q4/19	Q1/20 vs. Q1/19
Production					
Crude oil (bbls/d)	**4,041**	4,548	5,862	(11.1)%	(31.1)%
Sales					
Crude oil (bbls/d)	**5,911**	2,691	7,762	119.7%	(23.8)%
Inventory (mbbls)					
Opening crude oil inventory	**279**	108	189		
Crude oil production	**368**	418	528		
Crude oil sales	**(538)**	(247)	(699)		
Closing crude oil inventory	**109**	279	18		
Activity					
Capital expenditures	**12,002**	6,452	18,864	86.0%	(36.4)%
Gross wells drilled	**—**	—	2.00		
Net wells drilled	**—**	—	2.00		
Financial results					
Sales	**51,995**	21,872	63,582	137.7%	(18.2)%
Operating	**(17,373)**	(8,438)	(21,404)	105.9%	(18.8)%
General and administration	**(875)**	(1,477)	(1,039)	(40.8)%	(15.8)%
Current income taxes	**(9,597)**	(1,948)	(14,100)	392.7%	(31.9)%
Fund flows from operations	**24,150**	10,009	27,039	141.3%	(10.7)%
Netbacks ($/boe)					
Sales	**96.66**	88.35	91.02	9.4%	6.2%
Operating	**(32.30)**	(34.09)	(30.64)	(5.3)%	5.4%
General and administration	**(1.63)**	(5.97)	(1.49)	(72.7)%	9.4%
PRRT	**(17.21)**	(5.87)	(14.89)	193.2%	15.6%
Corporate income taxes	**(0.63)**	(2.00)	(5.30)	(68.5)%	(88.1)%
Fund flows from operations netback	**44.89**	40.42	38.70	11.1%	16.0%
Reference prices					
Dated Brent (US $/bbl)	**50.26**	63.25	63.20	(20.5)%	(20.5)%
Dated Brent ($/bbl)	**67.56**	83.49	84.01	(19.1)%	(19.6)%

Production

- Q1 2020 production decreased 11% quarter-over-quarter primarily due to planned and unplanned downtime relating to the installation of electric submersible pumps ("ESPs") on two of our wells and cyclone activity during the quarter. Quarterly production decreased 31% year-over-year primarily due to the production contribution from the two (2.0 net) well drilling program completed at the end of January 2019.
- Production volumes are managed to targets while meeting long-term supply requirements of our customers.

Activity

- During Q1 2020, we successfully installed ESPs on two of our wells. For the remainder of the year, we plan to perform various asset optimization projects and proactive maintenance.

Sales

- Crude oil in Australia is priced with reference to Dated Brent. During the quarter, we realized a $29.10 premium to average Dated Brent prices as a result of our premium received on Dated Brent coupled with the timing of sales weighted towards the beginning of the quarter.
- Q1 2020 sales increased compared to Q4 2019 due to higher sales volumes resulting from more liftings in the current quarter, combined with an increase in realized pricing.
- Year-over-year sales decreased due to lower sales volumes resulting from fewer liftings in the current quarter, partially offset by an increase in realized pricing.

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

- Operating expenses are deferred on the balance sheet until oil is sold at which point the related expenses are recognized into income.
- Q1 2020 operating expense increased compared to Q4 2019 primarily due to higher sales volumes in the current quarter. Q1 2020 operating expense decreased compared to Q1 2019 primarily due to lower sales volumes in the current quarter. On a per unit basis, Q1 2020 operating expense remained relatively consistent versus all comparable periods.

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 Petroleum Resource Rent Tax ("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 includes 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 2020, the effective rate on current taxes, inclusive of corporate allocations, is expected to be between 25% to 29% of pre-tax fund flows from operations. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.

United States Business Unit

Overview

- Entered the United States in 2014 and acquired additional producing assets in the Hilight field in 2018.
- Interests include approximately 144,600 net acres of land (69% 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 ($M except as indicated)	Q1 2020	Q4 2019	Q1 2019	Q1/20 vs. Q4/19	Q1/20 vs. Q1/19
Production and sales					
Crude oil (bbls/d)	**2,487**	3,161	1,742	(21.3)%	42.8%
NGLs (bbls/d)	**1,079**	1,156	929	(6.7)%	16.1%
Natural gas (mmcf/d)	**6.72**	8.20	5.89	(18.0)%	14.1%
Total (boe/d)	**4,685**	5,683	3,653	(17.6)%	28.3%
Production mix (% of total)					
Crude oil	**53%**	56%	48%		
NGLs	**23%**	20%	25%		
Natural gas	**24%**	24%	27%		
Activity					
Capital expenditures	**45,349**	3,132	20,036	1,347.9%	126.3%
Acquisitions	**5,858**	575	43		
Gross wells drilled	**9.00**	—	3.00		
Net wells drilled	**8.90**	—	3.00		
Financial results					
Sales	**15,828**	22,885	14,897	(30.8)%	6.2%
Royalties	**(4,016)**	(5,316)	(3,933)	(24.5)%	2.1%
Operating	**(5,549)**	(4,996)	(3,432)	11.1%	61.7%
General and administration	**(1,970)**	(2,099)	(1,891)	(6.1)%	4.2%
Fund flows from operations	**4,293**	10,474	5,641	(59.0)%	(23.9)%
Netbacks ($/boe)					
Sales	**37.12**	43.77	45.31	(15.2)%	(18.1)%
Royalties	**(9.42)**	(10.17)	(11.96)	(7.4)%	(21.2)%
Operating	**(13.01)**	(9.56)	(10.44)	36.1%	24.6%
General and administration	**(4.62)**	(4.01)	(5.75)	15.2%	(19.7)%
Fund flows from operations netback	**10.07**	20.03	17.16	(49.7)%	(41.3)%
Realized prices					
Crude oil ($/bbl)	**53.92**	66.65	68.72	(19.1)%	(21.5)%
NGLs ($/bbl)	**21.45**	20.69	25.21	3.7%	(14.9)%
Natural gas ($/mcf)	**2.49**	1.73	3.80	43.9%	(34.5)%
Total ($/boe)	**37.12**	43.77	45.31	(15.2)%	(18.1)%
Reference prices					
WTI (US $/bbl)	**46.17**	56.96	54.90	(18.9)%	(15.9)%
WTI ($/bbl)	**62.06**	75.19	72.97	(17.5)%	(15.0)%
Henry Hub (US $/mcf)	**1.95**	2.50	3.15	(22.0)%	(38.1)%
Henry Hub ($/mcf)	**2.62**	3.30	4.19	(20.6)%	(37.5)%

Production

- Q1 2020 production decreased 18% from the prior quarter primarily due to natural decline and increased downtime, which was partially offset by production contributions from three (2.9 net) wells brought on production at the end of the quarter. Quarterly production increased 28% year-over-year primarily due to the contributions from our 2019 Hilight drilling program.

Activity

- During Q1 2020, we drilled nine (8.9 net) wells and completed and brought on production three (2.9) wells. The remaining six (6.0 net) wells were completed in April and are undergoing tie-in activities. This constitutes the completion of our planned drilling activities for 2020 in the United States.

Sales

- The price of our crude oil in the United States is directly linked to WTI and subject to local market differentials within the United States. The price of our natural gas in the United States is based on the Henry Hub index.
- Q1 2020 sales decreased compared to Q4 2019 due to lower production volumes combined with a decrease in realized prices.
- Q1 2020 sales increased compared to Q1 2019 due to higher production volumes from the 2019 drilling program, partially offset by a decrease in realized prices.

Royalties

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax. In Hilight, approximately 65% of the current production is subject to Fee royalties, 30% to Federal royalties and the remainder to State royalties. In East Finn, approximately 70% of the current production is subject to Federal royalties with the remainder split between State and Fee royalties.
- For the three months ended March 31, 2020, royalties as a percentage of sales remained relatively consistent versus comparable periods.

Operating

- The increase in operating expense in Q1 2020 versus Q4 2019 and Q1 2019 was due to increased maintenance activity in the current quarter.

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

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

Corporate

Overview

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

Operational and financial review

Corporate ($M)	Q1 2020	Q4 2019	Q1 2019
Production and sales			
Natural gas (mmcf/d)	**3.27**	1.66	—
Total (boe/d)	**546**	276	—
Activity			
Capital expenditures	**2,253**	(98)	3,608
Acquisitions	**21**	2,131	—
Financial results			
Sales	**1,079**	797	—
Royalties	**(299)**	(254)	—
Sales of purchased commodities	**56,108**	74,951	29,539
Purchased commodities	**(56,108)**	(74,951)	(29,539)
Operating	**(90)**	(59)	(231)
General and administration (expense) recovery	**(1,495)**	2,456	(620)
Current income taxes	**(233)**	98	(150)
Interest expense	**(19,982)**	(19,169)	(20,979)
Realized gain on derivatives	**49,419**	22,712	10,348
Realized foreign exchange gain (loss)	**8,523**	2,013	(2,050)
Realized other (expense) income	**(3,309)**	253	6,884
Fund flows from operations	**33,613**	8,847	(6,798)

Production

- Q1 2020 production averaged 546 boe/d as we benefited from a full quarter contribution from the two (1.3 net) Hungarian wells we tied-in midway through the fourth quarter of 2019.

Activity

- During Q1 2020, we received final ratification of the previously announced Kadarkút exploration license in western Hungary. We also received final approvals of the previously announced SA-07 license in Croatia, which is contiguous with our existing land position in the country.

Sales, royalties, and operating expense

- Sales, royalties, and operating expense in the corporate segment relate to natural gas production in Hungary.
- Sales of natural gas in Hungary are priced with reference to the TTF index less adjustments for processing. During the quarter we realized a price of $3.62/mcf versus the $4.23/mcf benchmark price.
- The calculation for royalties on natural gas in Hungary incorporates the Dated Brent benchmark prices and as a result the quarterly realized royalty percentage will fluctuate depending on the relative pricing for TTF as compared to Dated Brent. From Q4 2019 to Q1 2020, TTF and Dated Brent benchmark prices both decreased by similar rates, as such royalties remained relatively consistent for this same period.
- Operating expense relates to contract operating costs, which equated to $1.82/boe during Q1 2020.

Purchased commodities

- Purchased commodities and the associated sales relate to amounts purchased from third parties, primarily to manage positions on pipelines in North America. 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, 2020 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 2020 remained relatively consistent compared to Q4 2019.
- Interest expense decreased in Q1 2020 compared to Q1 2019 due the impact of the USD-to-EUR cross-currency interest rate swaps entered into in Q2 2019.

Realized gain or loss on derivatives

- The realized gain on derivatives for the three months ended March 31, 2020 is related primarily to receipts for European natural gas and crude oil hedges of $33.5 million and a receipt of US $12.7 million in exchange for resetting the Euro principal amount of the CAD-to-EUR cross currency interest rate swap from €265.0 million to €275.8 million.
- A listing of derivative positions as at March 31, 2020 is included in "Supplemental Table 2" of this MD&A.

Realized other (expense) income

- Realized other expense for the three months ended March 31, 2020, relates primarily to amounts uncertain to be received pursuant to a negotiated settlement of a legal matter.

Financial Performance Review

($M except per share)	Q1 2020	Q4 2019	Q3 2019	Q2 2019	Q1 2019	Q4 2018	Q3 2018	Q2 2018
Petroleum and natural gas sales	**328,314**	388,802	391,935	428,043	481,083	456,939	508,411	394,498
Net earnings (loss)	**(1,318,504)**	1,477	(10,229)	2,004	39,547	323,373	(15,099)	(61,364)
Net earnings (loss) per share								
Basic	**(8.42)**	0.01	(0.07)	0.01	0.26	2.12	(0.10)	(0.46)
Diluted	**(8.42)**	0.01	(0.07)	0.01	0.26	2.10	(0.10)	(0.46)

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

	Q1 2020		Q4 2019		Q1 2019	
	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	**328,314**	**36.35**	388,802	44.00	481,083	50.77
Royalties	**(31,125)**	**(3.45)**	(40,679)	(4.60)	(43,384)	(4.58)
Petroleum and natural gas revenues	**297,189**	**32.90**	348,123	39.40	437,699	46.19
Transportation	**(17,330)**	**(1.92)**	(15,570)	(1.76)	(16,700)	(1.76)
Operating	**(121,138)**	**(13.41)**	(110,583)	(12.52)	(122,422)	(12.92)
General and administration	**(13,317)**	**(1.47)**	(16,569)	(1.88)	(13,058)	(1.38)
PRRT	**(9,256)**	**(1.02)**	(1,453)	(0.16)	(10,400)	(1.10)
Corporate income taxes	**(574)**	**(0.06)**	5,835	0.66	(15,750)	(1.66)
Interest expense	**(19,982)**	**(2.21)**	(19,169)	(2.17)	(20,979)	(2.21)
Realized gain on derivative instruments	**49,419**	**5.47**	22,712	2.57	10,348	1.09
Realized foreign exchange gain (loss)	**8,523**	**0.94**	2,013	0.23	(2,050)	(0.22)
Realized other (expense) income	**(3,309)**	**(0.37)**	253	0.03	6,884	0.73
Fund flows from operations	**170,225**	**18.85**	215,592	24.40	253,572	26.76

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

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

($M)	Q1 2020	Q4 2019	Q1 2019
Fund flows from operations	**170,225**	215,592	253,572
Equity based compensation	**(12,997)**	(11,233)	(22,843)
Unrealized gain (loss) on derivative instruments	**9,316**	(30,362)	(14,277)
Unrealized foreign exchange (loss) gain	**(9,982)**	42,848	23,258
Unrealized other expense	**(209)**	(204)	(205)
Accretion	**(9,738)**	(7,833)	(7,986)
Depletion and depreciation	**(157,807)**	(139,940)	(177,029)
Deferred tax	**257,542**	(21,335)	(14,943)
Impairment	**(1,564,854)**	(46,056)	—
Net (loss) earnings	**(1,318,504)**	1,477	39,547

Fluctuations in net income from period-to-period are caused by changes in both cash and non-cash based income and charges. Cash based items are reflected in fund flows from operations. Non-cash items include: equity based compensation expense, unrealized gains and losses on derivative instruments, unrealized foreign exchange gains and losses, accretion, depletion and depreciation expense, and deferred taxes. In addition, non-cash items may also include gains resulting from business combinations or charges resulting from impairment or impairment reversals.

Equity based compensation

Equity based compensation expense relates primarily to non-cash compensation expense attributable to long-term incentives granted to directors, officers, and employees under security-based arrangements, including the Vermilion Incentive Plan ("VIP"), a security-based compensation arrangement ("Five-Year Compensation Arrangement"), and the Deferred Share Unit Plan ("DSU Plan").

Equity based compensation expense in Q1 2020 increased compared to Q4 2019 due to a downward revision in performance factor assumptions recorded in Q4 2019 and decreased compared to Q1 2019 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 forecasts for future prices and rates. As Vermilion uses derivative instruments to manage the commodity price exposure of our future crude oil and natural gas production, we will normally recognize unrealized gains on derivative instruments when future commodity price forecasts decline and vice-versa. As derivative instruments are settled, the unrealized gain or loss previously recognized is reversed, and the settlement results in a realized gain or loss on derivative instruments.

For the three months ended March 31, 2020, we recognized a net unrealized gain on derivative instruments of $9.3 million. Of that we recognized an unrealized gain on derivative instruments consisting of $36.4 million on our crude oil commodity derivative instruments, $40.0 million on our European natural gas derivative instruments and $39.0 million from our USD-to-CAD cross currency interest rate swaps. These USD-to-CAD cross currency interest rate swaps are entered into on a monthly basis to hedge the foreign exchange movements on USD borrowings on our revolving credit facility. As such, unrealized gains and losses on our cross currency interest swaps are offset by unrealized losses and gains on foreign exchange relating to the underlying USD borrowings from our revolving credit facility.

The unrealized gain on derivative instruments is offset by an unrealized loss on derivative instruments consisting of $63.8 million on our equity swaps, $21.6 million of ineffectiveness from hedge accounting due to the change in the CAD-to-EUR cross currency interest rate swap principal from €265.0 million to €275.8 million, and $18.8 million on foreign exchange swaps.

Unrealized foreign exchange gains or losses

As a result of Vermilion's international operations, Vermilion has monetary assets and liabilities denominated in currencies other than the Canadian dollar. These monetary assets and liabilities include cash, receivables, payables, long-term debt, derivative instruments and intercompany loans. Unrealized foreign exchange gains and losses result from translating these monetary assets and liabilities from their underlying currency to the Canadian dollar.

In 2020, unrealized foreign exchange gains and losses primarily resulted from:

- The translation of Euro denominated intercompany loans from Vermilion Energy Inc. to our international subsidiaries. An appreciation in the Euro against the Canadian dollar will result in an unrealized foreign exchange gain (and vice-versa). Under IFRS, the offsetting foreign exchange loss or gain is recorded as a currency translation adjustment within other comprehensive income. As a result, consolidated comprehensive income reflects the offsetting of these translation adjustments while net earnings reflects only the parent company's side of the translation.
- The translation of USD borrowings on our revolving credit facility. The unrealized foreign exchange gains or losses on these borrowings are offset by unrealized derivative gains or losses on associated USD-to-CAD cross currency interest rate swaps (discussed further below).
- The translation of our USD denominated senior unsecured notes for the period from December 31, 2018 to June 12, 2019. Effective June 12, 2019, the USD senior notes were hedged by a USD-to-CAD cross currency interest rate swap.

For the three months ended March 31, 2020, the impact of the Euro strengthening 6.9% against the Canadian dollar resulted in a $18.3 million unrealized gain on our intercompany loans. This was offset with an unrealized loss of $28.7 million on our USD borrowings from our revolving credit facility.

As at March 31, 2020, a $0.01 appreciation of the Euro against the Canadian dollar would result in a $1.2 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 $0.6 million increase to net earnings as a result of an unrealized gain on foreign exchange.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. Accretion expense in Q1 2020 increased compared to Q4 2019 and Q1 2019 primarily attributable to a weakening Canadian dollar versus the Euro and new obligations recognized.

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 Q1 2020 of $17.47 increased from $15.84 in Q4 2019 primarily due to an increase in proved plus probable reserves recognized in the fourth quarter of 2019. For the three months ended March 31, 2020, depletion and depreciation on a per boe basis of $17.47 decreased from $18.68 in the respective comparable period in 2019 primarily due to the increase in proved plus probable reserves recognized in the fourth quarter of 2019.

Deferred tax

Deferred tax assets arise when the tax basis of an asset exceeds its accounting basis (known as a deductible temporary difference). Conversely, deferred tax liabilities arise when the tax basis of an asset is less than its accounting basis (known as a taxable temporary difference). Deferred tax assets are recognized only to the extent that it is probable that there are future taxable profits against which the deductible temporary difference can be utilized. Deferred tax assets and liabilities are measured at the enacted or substantively enacted tax rate that is expected to apply when the asset is realized, or the liability is settled.

As such, fluctuations in deferred tax expenses and recoveries primarily arise as a result of: changes in the accounting basis of an asset or liability without a corresponding tax basis change (e.g. when derivative assets and liabilities are marked-to-market or when accounting depletion differs from tax depletion), changes in available tax losses (e.g. if they are utilized to offset taxable income), changes in estimated future taxable profits resulting in a derecognition or recognition of deferred tax assets, and changes in enacted or substantively enacted tax rates.

For the three months ended March 31, 2020, a deferred tax recovery of $257.5 million was recognized and is primarily related to the impairment losses recognized in Q1 2020, partially offset by derecognition of a portion of non-expiring tax loss pools in Canada ($18.9 million), Ireland ($78.1 million), and Australia ($36.8 million) as there is uncertainty as to Vermilion's ability to fully utilize such losses based on commodity price forecasts as at March 31, 2020.

Impairment

Impairment losses are recognized when indicators of impairment arise and the carrying amount of a cash generating unit ("CGU") exceeds its recoverable amount, determined as the higher of fair value less costs of disposal or value-in-use. In the first quarter of 2020, indicators of impairment were present due to global commodity price forecasts deteriorating from a decrease in demand and an increase of supply around the world. As a result of the indicators of impairment, the Company performed an impairment test on all CGUs whereby the recoverable amount of each CGU was compared against its carrying amount. The recoverable amounts were determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 11.5%. Based on the results of the impairment tests completed, the Company recognized non-cash impairment charges of $1.2 billion (net of $0.4 billion income tax recovery).

In the fourth quarter of 2019, an indicator of impairment was present in the Ireland CGU due to declining natural gas price forecasts. As a result of the indicator of impairment, the Company performed an impairment test on its Ireland CGU whereby the recoverable amount was compared against its carrying amount. The recoverable amount was determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 9.0%. Based on the results of the impairment test completed, the Company recognized a non-cash impairment charge of $34.6 million (net of $11.5 million income tax recovery).

Financial Position Review

Balance sheet strategy

We believe that our balance sheet supports our defined growth initiatives and our focus is on managing and maintaining a conservative balance sheet. To ensure that our balance sheet continues to support our defined growth initiatives, we regularly review whether our forecast of fund flows from operations is sufficient to finance planned capital expenditures, dividends, and abandonment and reclamation expenditures. To the extent that fund flows from operations forecasts are not expected to be sufficient to fulfill such expenditures, we will evaluate our ability to finance any shortfall with debt (including borrowing using the unutilized capacity of our existing revolving credit facility), issuances of 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 dividend policy and exploration and development capital plans.

In the current economic and commodity outlook following the outbreak of COVID-19, there is uncertainty regarding our ability to achieve a 100% payout ratio at a reasonable level of capital expenditures. Therefore, in the first quarter of 2020, we reduced our 2020 capital budget by $80 to $100 million and reduced our March dividend to $0.115. Subsequent to the first quarter of 2020, the board of directors suspended the monthly dividend as a further measure to strengthen the financial position of the Company during this period of weak commodity prices.

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, 2020	Dec 31, 2019
Long-term debt	**1,994,044**	1,924,665
Current liabilities	**506,315**	416,210
Current assets	**(344,736)**	(347,681)
Net debt	**2,155,623**	1,993,194
Ratio of net debt to four quarter trailing fund flows from operations	**2.61**	2.20

As at March 31, 2020, net debt increased to $2.2 billion (December 31, 2019 - $2.0 billion) primarily due to the impact of increased accounts payable and accrued liabilities. The ratio of net debt to four quarter trailing fund flows from operations increased to 2.61 (December 31, 2019 - 2.20) due to the increase to net debt combined with lower four quarter trailing fund flows from operations.

Long-term debt

The balances recognized on our balance sheet are as follows:

	As at	
($M)	Mar 31, 2020	Dec 31, 2019
Revolving credit facility	**1,572,802**	1,539,225
Senior unsecured notes	**421,242**	385,440
Long-term debt	**1,994,044**	1,924,665

Revolving Credit Facility

In Q1 2020, we negotiated an extension to our $2.1 billion revolving credit facility to extend the maturity to May 31, 2024. All other terms within the facility remained the same.

As at March 31, 2020, Vermilion had in place a bank revolving credit facility maturing May 31, 2024 with terms and outstanding positions as follows:

($M)	As at Mar 31, 2020	Dec 31, 2019
Total facility amount	**2,100,000**	2,100,000
Amount drawn	**(1,572,802)**	(1,539,225)
Letters of credit outstanding	**(11,671)**	(10,230)
Unutilized capacity	**515,527**	550,545

As at March 31, 2020, the revolving credit facility was subject to the following financial covenants:

Financial covenant	Limit	As at Mar 31, 2020	Dec 31, 2019
Consolidated total debt to consolidated EBITDA	Less than 4.0	**2.19**	1.94
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	**1.73**	1.56
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	**12.21**	13.46

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

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

In addition, our revolving credit facility has provisions relating to our liability management ratings in Alberta and Saskatchewan whereby if our security adjusted liability management ratings fall below specified limits in a province, a portion of the asset retirement obligations are included in the definitions of consolidated total debt and consolidated total senior debt. An event of default occurs if our security adjusted liability management ratings breach additional lower limits for a period greater than 90 days. As of March 31, 2020, Vermilion's liability management ratings were higher than the specified levels, and as such, no amounts relating to asset retirement obligations were included in the calculation of consolidated total debt and consolidated total senior debt.

Senior Unsecured Notes

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

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

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

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

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

Cross currency interest rate swaps

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

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

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

In Q1 2020, Vermilion reset the Euro principal amount of the CAD-to-EUR cross currency interest rate swap from €265.0 million to €275.8 million and in exchange received US $12.7 million. All other terms of the instrument remained the same and hedge accounting continues to be applied to this transaction; however, as a result of the transaction the change in the Euro principal amount is recognized as hedge ineffectiveness with changes in value recognized in the consolidated statement of net earnings. As at March 31, 2020, ineffectiveness of $21.6 million was recognized within (gain) loss on derivative instruments in the consolidated statement of net earnings.

Shareholders' capital

In total, dividends declared for the three months ended March 31, 2020 were $90.1 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 to February 2020	$0.230
March 2020	$0.115
April 2020 onwards	$0.000

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.

In the current economic and commodity outlook following the outbreak COVID-19, there was uncertainty regarding our ability to achieve a 100% payout ratio at a reasonable level of capital expenditures. Therefore, in the first quarter of 2020, we reduced our 2020 capital budget by $80 to $100 million and reduced our March dividend to $0.115. Subsequent to the first quarter of 2020, the board of directors suspended the monthly dividend as a further measure to strengthen the financial position of the Company during this period of weak commodity prices. 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, 2019	**156,290**	**4,119,031**
Shares issued for the Dividend Reinvestment Plan	**504**	**7,645**
Equity based compensation	**226**	**2,117**
Balance as at March 31, 2020	**157,020**	**4,128,793**

As at March 31, 2020, there were approximately 2.3 million equity based compensation awards outstanding. As at April 28, 2020, there were approximately 157.0 million common shares issued and outstanding.

We have a normal course issuer bid ("NCIB") approved by the Toronto Stock Exchange ("TSX") that allows us to purchase up to 7,750,000 common shares (representing approximately 5% of shares outstanding common shares) beginning August 9, 2019 and ending August 8, 2020. Any common shares that are purchased under the NCIB will be canceled upon their purchase. As at March 31, 2020, no shares have been purchased pursuant to the NCIB.

Asset Retirement Obligations

As at March 31, 2020, asset retirement obligations were $207.2 million compared to $618.2 million as at December 31, 2019. The decrease in asset retirement obligations is primarily attributable to an increase in the credit spread from December 31, 2019 to March 31, 2020.

The present value of the obligation is calculated using a credit-adjusted risk-free rate, calculated using a credit spread added to risk-free rates based on long-term, risk-free government bonds. Vermilion's credit spread is determined as the yield to maturity on its senior unsecured notes as at the reporting period.

The risk-free rates and credit spread used as inputs to discount the obligations were as follows:

	Mar 31, 2020	Dec 31, 2019	Change
Canada	**1.3 %**	1.7 %	(0.4)%
France	**0.7 %**	0.9 %	(0.2)%
Netherlands	**(0.3)%**	(0.1)%	(0.2)%
Germany	**— %**	0.3 %	(0.3)%
Ireland	**0.5 %**	0.6 %	(0.1)%
Australia	**1.2 %**	1.6 %	(0.4)%
United States	**1.3 %**	2.4 %	(1.1)%
Credit spread	**14.7 %**	5.3 %	9.4 %

Risks and Uncertainties

Vermilion is exposed to various market and operational risks. For a discussion of these risks, please see Vermilion's MD&A and Annual Information Form, each for the year ended December 31, 2019 available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

COVID-19

The emergence of COVID-19 has resulted in emergency actions by governments worldwide which has had an effect in all of our operating jurisdictions. The actions taken by these governments have typically included, but is not limited to travel bans, mandatory and self-imposed quarantines and isolations, social distancing, and the closing of non-essential businesses which has had significant negative effects on economies, including a substantial decline in crude oil and natural gas demand.

The full extent of the risks surrounding the severity and timing of the COVID-19 pandemic is continually evolving and is not fully known at this time; therefore, there is significant risk and uncertainty which may have a material and adverse effect on our operations. The following risks disclosed in our Annual Information Form for the year ended December 31, 2019 may be exacerbated as a result of the COVID-19 pandemic: market risks related to the volatility of oil and gas prices, volatility of foreign exchange rates, volatility of the market price of common shares, and hedging arrangements; operational risks related to increasing operating costs or declines in production levels, operator performance and payment delays, and government regulations; financing risks related to declaration and payment of dividends, ability to obtain additional financing, ability to service debt, and variations in interest rates and foreign exchanges rates; and other risks related to cyber-security as our workforce moves to remote connections, accounting adjustments, effectiveness of internal controls, and reliance on key personnel, management, and labour.

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.

Critical Accounting Estimates

The preparation of financial statements in accordance with IFRS requires us to make estimates. Critical accounting estimates are those accounting estimates that require us to make assumptions about matters that are highly uncertain at the time the estimate is made and a different estimate could have been made in the current period or the estimate could change period-to-period.

The carrying amount of asset retirement obligations

The carrying amount of asset retirement obligations ($207.2 million as at March 31, 2020) is the present value of estimated future costs, discounted from the estimated abandonment date using a credit-adjusted risk-free rate. Estimated future costs are based on our assessment of regulatory requirements and the present condition of our assets. The estimated abandonment date is based on the reserve life of the associated assets. The credit-adjusted risk-free rate is based on prevailing interest rates for the appropriate term, risk-free government bonds adjusted for our estimated credit spread (determined by reference to the trading prices for debt issued by similarly rated independent oil and gas producers, including our own senior unsecured notes). Changes in these estimates would result in a change in the carrying amount of asset retirement obligations and capital assets and, to a significantly lesser degree, future accretion and depletion expense.

The estimated credit-adjusted risk-free rate may change from period to period in response to market conditions in Canada and the international jurisdictions that we operate in. A 0.5% increase or decrease in the credit-adjusted risk-free rate would decrease or increase asset retirement obligations by approximately $9.8 million.

The recognition of deferred tax assets

In Ireland, we have $1.0 billion of non-expiring tax loss pools where $241.3 million of deferred tax assets has not been recognized as there is uncertainty on our ability to fully use these losses based on estimated future taxable profits. Estimated future taxable profits are calculated using proved and probable reserves and forecast pricing for European natural gas.

In Canada, we have $75.7 million of tax pools where $18.9 million of deferred tax assets has not been recognized as there is uncertainty on our ability to fully use these losses based on estimated future taxable profits. Estimated future taxable profits are calculated using proved and probable reserves and forecast pricing applicable to our Canadian operations.

As a result, the carrying value of deferred tax assets may change from period-to-period due to changes in forecast pricing. A 5% increase or decrease in proved and probable reserves in our Ireland segment would increase or decrease deferred tax assets (with a corresponding deferred tax recovery or expense) by approximately $16.5 million. A 5% increase or decrease in proved and probable reserves in our Canada segment would increase or decrease deferred tax assets (with a corresponding deferred tax recovery or expense) by approximately $77.0 million.

The estimated recoverable amount of cash generating units

Each reporting period, we assess our cash generating units for indicators of impairment or impairment reversal. If an indicator of impairment or impairment reversal is identified, we estimate the recoverable amount of the cash generating unit. In the first quarter of 2020, indicators of impairment were present due to global commodity price forecasts deteriorating from a decrease in demand and an increase of supply around the world. As a result of the indicators of impairment, the Company performed an impairment test on all CGUs whereby the recoverable amount of each CGU was compared against its carrying amount. The recoverable amounts were determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 11.5%. Based on the results of the impairment tests completed, the Company recognized non-cash impairment charges of $1.2 billion (net of $0.4 billion income tax recovery).

Changes in any of the key judgments, such as a revision in reserves, changes in forecast commodity prices, foreign exchange rates, capital or operating costs would impact the estimated recoverable amount. As at March 31, 2020, a 1% increase in the assumed after-tax discount rate would reduce the estimated recoverable amount by $147.5 million (resulting in a $1.7 billion impairment) while a 5% decrease in revenues (due to a decrease in commodity price forecasts or reserve estimates) would reduce the estimated recoverable amount by $310.4 million (resulting in a $1.9 billion impairment).

Internal Control Over Financial Reporting

Other than Vermilion's response to COVID-19, there has been no change in Vermilion's internal control over financial reporting ("ICFR") during the period covered by this MD&A that materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Due to the COVID-19 pandemic, Vermilion has implemented social distancing measures which require deemed non-critical employees to work remotely and has encouraged critical staff to do the same. These measures may have an effect on the design and performance of internal controls throughout the Company and will be continually monitored to mitigate any risks associated with changes in its control environment.

Recently Adopted Accounting Pronouncements

Vermilion did not adopt any new accounting pronouncements as at March 31, 2020.

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, 2020, 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 2020			Q1 2019		
	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Liquids $/bbl	Natural Gas $/mcf	Total $/boe
Canada						
Sales	41.24	1.90	**28.60**	57.36	2.47	39.87
Royalties	(5.12)	(0.05)	**(3.08)**	(7.24)	(0.13)	(4.59)
Transportation	(2.64)	(0.21)	**(2.06)**	(2.52)	(0.18)	(1.94)
Operating	(14.58)	(1.35)	**(11.85)**	(13.30)	(1.49)	(11.52)
Operating netback	18.90	0.29	**11.61**	34.30	0.67	21.82
General and administration			**(0.52)**			(0.49)
Fund flows from operations netback			**11.09**			21.33
France						
Sales	61.08	—	**61.08**	81.52	1.76	80.72
Royalties	(9.72)	—	**(9.72)**	(11.14)	(0.01)	(11.01)
Transportation	(4.01)	—	**(4.01)**	(3.13)	—	(3.09)
Operating	(17.10)	—	**(17.10)**	(15.53)	—	(15.36)
Operating netback	30.25	—	**30.25**	51.72	1.75	51.26
General and administration			**(3.71)**			(3.57)
Current income taxes			**—**			(7.52)
Fund flows from operations netback			**26.54**			40.17
Netherlands						
Sales	64.32	4.34	**26.45**	67.10	8.63	51.97
Royalties	—	(0.03)	**(0.19)**	—	(0.13)	(0.79)
Operating	—	(2.03)	**(12.03)**	—	(1.79)	(10.61)
Operating netback	64.32	2.28	**14.23**	67.10	6.71	40.57
General and administration			**(0.75)**			(1.14)
Current income taxes			**—**			(5.38)
Fund flows from operations netback			**13.48**			34.05
Germany						
Sales	59.72	4.29	**34.70**	78.50	7.94	56.09
Royalties	(2.80)	(0.54)	**(3.12)**	(5.83)	(1.11)	(6.44)
Transportation	(11.93)	(0.28)	**(4.38)**	(10.86)	(0.43)	(4.84)
Operating	(22.84)	(2.32)	**(16.29)**	(27.52)	(2.20)	(17.14)
Operating netback	22.15	1.15	**10.91**	34.29	4.20	27.67
General and administration			**(5.77)**			(5.54)
Fund flows from operations netback			**5.14**			22.13
Ireland						
Sales	—	4.66	**28.03**	—	8.55	51.30
Transportation	—	(0.30)	**(1.82)**	—	(0.25)	(1.50)
Operating	—	(1.12)	**(6.71)**	—	(0.82)	(4.91)
Operating netback	—	3.24	**19.50**	—	7.48	44.89
General and administration			**(0.62)**			(0.42)
Fund flows from operations netback			**18.88**			44.47

	Q1 2020 Liquids $/bbl	Q1 2020 Natural Gas $/mcf	Q1 2020 Total $/boe	Q1 2019 Liquids $/bbl	Q1 2019 Natural Gas $/mcf	Q1 2019 Total $/boe
Australia						
Sales	96.66	—	**96.66**	91.02	—	91.02
Operating	(32.30)	—	**(32.30)**	(30.64)	—	(30.64)
PRRT [1]	(17.21)	—	**(17.21)**	(14.89)	—	(14.89)
Operating netback	47.15	—	**47.15**	45.49	—	45.49
General and administration			**(1.63)**			(1.49)
Current income taxes			**(0.63)**			(5.30)
Fund flows from operations netback			**44.89**			38.70
United States						
Sales	44.09	2.49	**37.12**	53.58	3.80	45.31
Royalties	(11.12)	(0.67)	**(9.42)**	(13.95)	(1.09)	(11.96)
Operating	(13.17)	(2.09)	**(13.01)**	(10.85)	(1.55)	(10.44)
Operating netback	19.80	(0.27)	**14.69**	28.78	1.16	22.91
General and administration			**(4.62)**			(5.75)
Fund flows from operations netback			**10.07**			17.16
Total Company						
Sales	51.40	2.94	**36.35**	66.62	5.10	50.77
Realized hedging gain (loss)	7.77	0.44	**5.47**	1.69	0.06	1.09
Royalties	(5.77)	(0.09)	**(3.45)**	(7.30)	(0.19)	(4.58)
Transportation	(2.58)	(0.18)	**(1.92)**	(2.33)	(0.17)	(1.76)
Operating	(16.97)	(1.50)	**(13.41)**	(16.13)	(1.47)	(12.92)
PRRT [1]	(1.85)	—	**(1.02)**	(1.96)	—	(1.10)
Operating netback	32.00	1.61	**22.02**	40.59	3.33	31.50
General and administration			**(1.47)**			(1.38)
Interest expense			**(2.21)**			(2.21)
Realized foreign exchange loss			**0.94**			(0.22)
Other income			**(0.37)**			0.73
Corporate income taxes			**(0.06)**			(1.66)
Fund flows from operations netback			**18.85**			26.76

(1) Vermilion considers Australian PRRT to be an operating item and, accordingly, has included PRRT in the calculation of operating netbacks. Current income taxes presented above excludes PRRT.

Supplemental Table 2: Hedges

The prices in these tables may represent the weighted averages for several contracts with foreign currency amounts translated to the disclosure currency using forward rates as at the month-end date. The weighted average price for the portfolio of options listed below may not have the same payoff profile as the individual contracts. As such, the presentation of the weighted average prices is purely for indicative purposes.

The following tables outline Vermilion's outstanding risk management positions as at March 31, 2020:

	Unit	Currency	Bought Put Volume	Weighted Average Bought Put Price	Sold Call Volume	Weighted Average Sold Call Price	Sold Put Volume	Weighted Average Sold Put Price	Sold Swap Volume	Weighted Average Sold Swap Price	Bought Swap Volume	Weighted Average Bought Swap Price
Dated Brent												
Q1 2020	bbl	USD	3,000	62.25	3,000	67.39	3,000	55.58	—	—	—	—
Q2 2020	bbl	USD	5,000	50.18	5,000	54.94	5,000	42.95	—	—	—	—
Q3 2020	bbl	USD	1,000	28.00	1,000	32.50	1,000	18.00	—	—	—	—
Q4 2020	bbl	USD	1,000	28.00	1,000	32.50	1,000	18.00	—	—	—	—
Q1 2021	bbl	USD	1,000	28.00	1,000	32.50	1,000	18.00	—	—	—	—
Q2 2021	bbl	USD	1,000	28.00	1,000	32.50	1,000	18.00	—	—	—	—
Q3 2021	bbl	USD	1,000	28.00	1,000	32.50	1,000	18.00	—	—	—	—
Q4 2021	bbl	USD	1,000	28.00	1,000	32.50	1,000	18.00	—	—	—	—
Q1 2022	bbl	USD	1,000	28.00	1,000	32.50	1,000	18.00	—	—	—	—
Q2 2022	bbl	USD	1,000	28.00	1,000	32.50	1,000	18.00	—	—	—	—
WTI												
Q1 2020	bbl	USD	9,250	54.24	6,000	60.82	9,250	46.41	—	—	—	—
Q2 2020	bbl	USD	18,250	43.13	15,000	46.86	18,250	36.52	—	—	—	—
Q3 2020	bbl	USD	4,500	44.44	4,500	49.47	4,500	37.78	—	—	—	—
Q4 2020	bbl	USD	2,500	58.20	2,500	61.85	2,500	52.00	—	—	—	—
1-month WTI Calendar Spread												
Q2 2020	bbl	USD	7,500	(1.30)	—	—	—	—	—	—	—	—
Q3 2020	bbl	USD	7,500	(1.30)	—	—	—	—	—	—	—	—
AECO												
Q2 2020	mcf	CAD	—	—	—	—	—	—	19,904	1.60	—	—
Q3 2020	mcf	CAD	—	—	—	—	—	—	19,904	1.60	—	—
Q4 2020	mcf	CAD	—	—	—	—	—	—	6,707	1.60	—	—
AECO Basis (AECO less NYMEX Henry Hub)												
Q1 2020	mcf	USD	—	—	—	—	—	—	2,500	(0.93)	—	—
Q2 2020	mcf	USD	—	—	—	—	—	—	52,500	(1.12)	—	—
Q3 2020	mcf	USD	—	—	—	—	—	—	50,000	(1.12)	—	—
Q4 2020	mcf	USD	—	—	—	—	—	—	36,739	(1.11)	—	—
Q1 2021	mcf	USD	—	—	—	—	—	—	30,000	(1.11)	—	—
Q2 2021	mcf	USD	—	—	—	—	—	—	45,000	(1.08)	—	—
Q3 2021	mcf	USD	—	—	—	—	—	—	45,000	(1.08)	—	—
Q4 2021	mcf	USD	—	—	—	—	—	—	35,054	(1.09)	—	—
Q1 2022	mcf	USD	—	—	—	—	—	—	30,000	(1.10)	—	—
Q2 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)	—	—
Q3 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)	—	—
Q4 2022	mcf	USD	—	—	—	—	—	—	11,793	(1.09)	—	—
NYMEX Henry Hub												
Q1 2020	mcf	USD	27,253	1.60	—	—	—	—	—	—	—	—
Q2 2020	mcf	USD	125,000	1.73	20,000	2.15	14,835	1.87	10,000	2.01	—	—
Q3 2020	mcf	USD	125,000	1.73	20,000	2.15	—	—	10,000	2.01	—	—
Q4 2020	mcf	USD	42,120	1.73	6,739	2.15	—	—	3,370	2.01	—	—

	Unit	Currency	Bought Put Volume	Weighted Average Bought Put Price	Sold Call Volume	Weighted Average Sold Call Price	Sold Put Volume	Weighted Average Sold Put Price	Sold Swap Volume	Weighted Average Sold Swap Price	Bought Swap Volume	Weighted Average Bought Swap Price
NBP												
Q1 2020	mcf	EUR	41,765	5.21	41,765	5.76	41,765	3.95	—	—	—	—
Q2 2020	mcf	EUR	41,765	5.21	41,765	5.58	41,765	3.83	—	—	—	—
Q3 2020	mcf	EUR	41,765	5.21	41,765	5.57	41,765	3.83	—	—	—	—
Q4 2020	mcf	EUR	61,419	5.28	63,875	5.84	61,419	3.90	—	—	—	—
Q1 2021	mcf	EUR	58,962	5.37	61,419	5.93	58,962	3.88	—	—	—	—
Q2 2021	mcf	EUR	49,135	5.37	49,135	5.92	49,135	3.87	—	—	—	—
Q3 2021	mcf	EUR	49,135	5.37	49,135	5.91	49,135	3.87	—	—	—	—
Q4 2021	mcf	EUR	58,962	5.37	58,962	5.85	58,962	3.88	—	—	—	—
Q1 2022	mcf	EUR	29,481	5.21	29,481	6.05	29,481	3.65	4,913	5.86	—	—
Q2 2022	mcf	EUR	22,111	5.09	22,111	5.82	22,111	3.50	4,913	5.86	—	—
Q3 2022	mcf	EUR	9,827	4.80	9,827	5.43	9,827	3.37	4,913	5.86	—	—
Q4 2022	mcf	EUR	9,827	4.80	9,827	5.42	9,827	3.37	4,913	5.86	—	—
Q1 2023	mcf	EUR	7,370	4.74	7,370	5.25	7,370	3.32	—	—	—	—
NBP Basis (NBP less NYMEX Henry Hub)												
Q1 2020	mcf	USD	15,000	2.61	15,000	3.98	—	—	—	—	—	—
Q2 2020	mcf	USD	15,000	2.61	15,000	3.98	—	—	—	—	15,000	2.02
Q3 2020	mcf	USD	15,000	2.61	15,000	3.98	—	—	—	—	15,000	2.02
Q4 2020	mcf	USD	10,000	3.24	10,000	3.98	—	—	—	—	—	—
TTF												
Q1 2020	mcf	EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—	—	—
Q2 2020	mcf	EUR	13,512	5.36	9,827	6.15	13,512	3.73	4,913	5.54	—	—
Q3 2020	mcf	EUR	13,512	5.36	9,827	6.15	13,512	3.73	3,258	5.45	—	—
Q4 2020	mcf	EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—	—	—
Q2 2021	mcf	EUR	2,457	4.25	2,457	4.32	2,457	2.93	—	—	—	—
Q3 2021	mcf	EUR	2,457	4.25	2,457	4.31	2,457	2.93	—	—	—	—
Q1 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q2 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q3 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q4 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q1 2023	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
TTF Basis (TTF less NYMEX Henry Hub)												
Q2 2020	mcf	USD	2,500	3.50	2,500	4.00	—	—	5,000	3.21	7,500	2.02
Q3 2020	mcf	USD	2,500	3.50	2,500	4.00	—	—	5,000	3.21	7,500	2.02

Cross Currency Interest Rate		Receive Notional Amount		Receive Rate	Pay Notional Amount		Pay Rate
Swap	Jan 2020 - Mar 2025	300,000,000	USD	5.625%	275,757,832	EUR	3.275%
Swap	April 2020	55,000,000	USD	LIBOR + 1.70%	77,275,000	CAD	CDOR + 1.15%

Foreign Currency Swaps						Average Rate
Swap	April 2020	1,109,685,189	USD	1,579,900,000	CAD	1.4237

VET Equity Swaps		Initial Share Price		Share Volume
Swap	Jan 2020 - Sep 2021	20.9788	CAD	2,250,000
Swap	Jan 2020 - Oct 2021	22.4587	CAD	1,500,000

The following sold option instruments allow the counterparties, at the specified date, to enter into a derivative instrument contract with Vermilion at the detailed terms:

Period if Option Exercised	Unit	Currency	Option Expiration Date	Bought Put Volume	Weighted Average Bought Put Price	Sold Call Volume	Weighted Average Sold Call Price	Sold Put Volume	Weighted Average Sold Put Price	Swap Volume	Weighted Average Swap Price
Dated Brent											
May 2020 - Apr 2021	bbl	USD	30-Apr-20	—	—	—	—	—	—	4,000	62.63
May 2020 - Apr 2022	bbl	USD	30-Apr-20	—	—	—	—	—	—	1,000	48.00
Jun 2020 - May 2021	bbl	USD	29-May-20	—	—	—	—	—	—	500	60.00
Jun 2020 - May 2021	bbl	USD	29-May-20	500	60.00	500	63.00	500	55.00	—	—
Jun 2020 - May 2022	bbl	USD	29-May-20	—	—	—	—	—	—	2,250	61.67
Jul 2020 - Jun 2022	bbl	USD	30-Jun-20	—	—	—	—	—	—	1,000	60.00
NBP											
Jan 2021 - Sep 2022	mcf	USD	30-Jun-20	—	—	—	—	—	—	2,457	6.45
Jan 2022 - Dec 2022	mcf	USD	30-Jun-20	—	—	—	—	—	—	9,827	6.45
Jan 2022 - Mar 2023	mcf	EUR	30-Jun-20	—	—	—	—	—	—	6,824	5.86
Oct 2020 - Jun 2022	mcf	EUR	30-Sep-20	—	—	—	—	—	—	2,457	6.15
WTI											
May 2020 - Apr 2022	bbl	USD	30-Apr-20							5,250	46.05

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Q1 2020	Q4 2019	Q1 2019
Drilling and development	**227,433**	97,114	197,291
Exploration and evaluation	**6,271**	3,511	4,762
Capital expenditures	**233,704**	100,625	202,053
Acquisitions	**11,337**	9,165	16,027
Acquisitions	**11,337**	9,165	16,027

By category ($M)	Q1 2020	Q4 2019	Q1 2019
Drilling, completion, new well equip and tie-in, workovers and recompletions	**208,164**	72,515	174,558
Production equipment and facilities	**17,627**	29,221	17,445
Seismic, studies, land and other	**7,913**	(1,111)	10,050
Capital expenditures	**233,704**	100,625	202,053
Acquisitions	**11,337**	9,165	16,027
Total capital expenditures and acquisitions	**245,041**	109,790	218,080

Capital expenditures by country ($M)	Q1 2020	Q4 2019	Q1 2019
Canada	**152,577**	66,643	128,055
France	**11,257**	8,745	22,086
Netherlands	**2,497**	9,651	6,349
Germany	**7,789**	5,177	3,044
Ireland	**(20)**	923	11
Australia	**12,002**	6,452	18,864
United States	**45,349**	3,132	20,036
Corporate	**2,253**	(98)	3,608
Total capital expenditures	**233,704**	100,625	202,053

Acquisitions by country ($M)	Q1 2020	Q4 2019	Q1 2019
Canada	**5,439**	5,003	14,660
Netherlands	**—**	—	908
Germany	**19**	1,456	416
United States	**5,858**	575	43
Corporate	**21**	2,131	—
Total acquisitions	**11,337**	9,165	16,027

In 2020, included in cash expenditures on acquisitions of $11.3 million is: $0.9 million net received to vendors in relation to the purchase of assets from other oil and gas producers; $0.4 million in asset improvements incurred subsequent to acquisitions for compliance with safety, environmental, and Vermilion's operating standards; $6.6 million paid to acquire land; and $5.2 million relating to the carry component of farm-in arrangements.

Supplemental Table 4: Production

	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18	Q2/18	Q1/18	Q4/17	Q3/17	Q2/17
Canada												
Crude oil & condensate (bbls/d)	**27,401**	27,399	27,682	28,844	29,164	29,557	28,477	17,009	9,272	9,703	9,288	9,205
NGLs (bbls/d)	**6,943**	7,005	6,632	7,352	6,968	6,816	6,126	5,589	5,106	5,235	4,891	3,745
Natural gas (mmcf/d)	**151.16**	145.14	145.14	151.87	151.37	146.65	136.77	127.32	106.21	107.91	103.92	93.68
Total (boe/d)	**59,537**	58,593	58,504	61,507	61,360	60,814	57,397	43,817	32,078	32,923	31,499	28,563
% of consolidated	**63%**	61%	60%	60%	59%	60%	59%	55%	46%	45%	46%	43%
France												
Crude oil (bbls/d)	**9,957**	10,264	10,347	9,800	11,342	11,317	11,407	11,683	11,037	11,215	10,918	11,368
Natural gas (mmcf/d)	**—**	—	—	—	0.77	0.82	—	—	—	—	—	—
Total (boe/d)	**9,957**	10,264	10,347	9,800	11,470	11,454	11,407	11,683	11,037	11,215	10,918	11,368
% of consolidated	**10%**	10%	11%	10%	11%	11%	12%	14%	16%	15%	16%	17%
Netherlands												
Condensate (bbls/d)	**87**	90	82	100	93	112	84	87	77	105	74	104
Natural gas (mmcf/d)	**48.33**	47.99	44.08	52.90	51.51	51.82	44.37	43.49	44.79	55.66	34.90	31.58
Total (boe/d)	**8,143**	8,088	7,429	8,917	8,677	8,749	7,479	7,335	7,541	9,381	5,890	5,368
% of consolidated	**8%**	8%	8%	9%	8%	9%	8%	9%	11%	13%	9%	8%
Germany												
Crude oil (bbls/d)	**909**	800	845	1,047	978	913	1,019	1,008	1,078	1,148	1,054	1,047
Natural gas (mmcf/d)	**14.64**	15.44	14.54	14.56	16.71	16.94	14.88	14.63	16.19	18.19	20.12	19.86
Total (boe/d)	**3,349**	3,373	3,269	3,474	3,763	3,736	3,498	3,447	3,777	4,180	4,407	4,357
% of consolidated	**3%**	3%	3%	3%	4%	4%	4%	4%	5%	6%	7%	6%
Ireland												
Natural gas (mmcf/d)	**41.38**	42.30	43.21	49.21	51.71	52.03	51.38	56.56	60.87	56.23	49.04	63.81
Total (boe/d)	**6,896**	7,049	7,202	8,201	8,619	8,672	8,563	9,426	10,144	9,372	8,173	10,634
% of consolidated	**7%**	7%	7%	8%	8%	9%	9%	12%	14%	13%	12%	16%
Australia												
Crude oil (bbls/d)	**4,041**	4,548	5,564	6,689	5,862	4,174	4,704	4,132	4,971	4,993	5,473	6,054
% of consolidated	**4%**	5%	6%	6%	6%	4%	5%	5%	7%	7%	8%	9%
United States												
Crude oil (bbls/d)	**2,487**	3,161	2,722	2,483	1,742	1,605	1,461	655	574	667	880	747
NGLs (bbls/d)	**1,079**	1,156	1,140	754	929	998	714	62	20	43	56	76
Natural gas (mmcf/d)	**6.72**	8.20	6.38	7.06	5.89	5.65	4.82	0.40	0.15	0.29	0.64	0.44
Total (boe/d)	**4,685**	5,683	4,925	4,414	3,653	3,545	2,979	784	618	758	1,043	896
% of consolidated	**5%**	6%	5%	4%	4%	3%	3%	1%	1%	1%	2%	1%
Corporate												
Natural gas (mmcf/d)	**3.27**	1.66	—	—	—	2.86	1.17	—	—	—	—	—
Total (boe/d)	**546**	276	—	—	—	477	195	—	—	—	—	—
% of consolidated	**—**	—	—	—	—	—	—	—	—	—	—	—
Consolidated												
Liquids (bbls/d)	**52,903**	54,421	55,014	57,071	57,078	55,493	53,991	40,225	32,134	33,109	32,634	32,346
% of consolidated	**54%**	56%	57%	55%	55%	55%	56%	50%	46%	45%	48%	48%
Natural gas (mmcf/d)	**265.51**	260.72	253.36	275.60	277.96	276.77	253.38	242.40	228.20	238.28	208.62	209.36
% of consolidated	**46%**	44%	43%	45%	45%	45%	44%	50%	54%	55%	52%	52%
Total (boe/d)	**97,154**	97,875	97,239	103,003	103,404	101,621	96,222	80,625	70,167	72,821	67,403	67,240

	2020	2019	2018	2017	2016	2015
Canada						
Crude oil & condensate (bbls/d)	**27,401**	28,266	21,154	9,051	9,171	11,357
NGLs (bbls/d)	**6,943**	6,988	5,914	4,144	2,552	2,301
Natural gas (mmcf/d)	**151.16**	148.35	129.37	97.89	84.29	71.65
Total (boe/d)	**59,537**	59,979	48,630	29,510	25,771	25,598
% of consolidated	**63%**	60%	56%	45%	40%	46%
France						
Crude oil (bbls/d)	**9,957**	10,435	11,362	11,084	11,896	12,267
Natural gas (mmcf/d)	**—**	0.19	0.21	—	0.44	0.97
Total (boe/d)	**9,957**	10,467	11,396	11,085	11,970	12,429
% of consolidated	**10%**	10%	13%	16%	19%	23%
Netherlands						
Condensate (bbls/d)	**87**	91	90	90	88	99
Natural gas (mmcf/d)	**48.33**	49.10	46.13	40.54	47.82	44.76
Total (boe/d)	**8,143**	8,274	7,779	6,847	8,058	7,559
% of consolidated	**8%**	8%	9%	10%	13%	14%
Germany						
Crude oil (bbls/d)	**909**	917	1,004	1,060	—	—
Natural gas (mmcf/d)	**14.64**	15.31	15.66	19.39	14.90	15.78
Total (boe/d)	**3,349**	3,468	3,614	4,291	2,483	2,630
% of consolidated	**3%**	3%	4%	6%	4%	5%
Ireland						
Natural gas (mmcf/d)	**41.38**	46.57	55.17	58.43	50.89	0.03
Total (boe/d)	**6,896**	7,762	9,195	9,737	8,482	5
% of consolidated	**7%**	8%	11%	14%	13%	—
Australia						
Crude oil (bbls/d)	**4,041**	5,662	4,494	5,770	6,304	6,454
% of consolidated	**4%**	6%	5%	8%	10%	12%
United States						
Crude oil (bbls/d)	**2,487**	2,531	1,078	666	393	231
NGLs (bbls/d)	**1,079**	996	452	50	29	7
Natural gas (mmcf/d)	**6.72**	6.89	2.78	0.39	0.21	0.05
Total (boe/d)	**4,685**	4,675	1,992	781	457	247
% of consolidated	**5%**	5%	2%	1%	1%	—
Corporate						
Natural gas (mmcf/d)	**3.27**	0.42	1.02	—	—	—
Total (boe/d)	**546**	70	169	—	—	—
% of consolidated	**—**	—	—	—	—	—
Consolidated						
Liquids (bbls/d)	**52,903**	55,886	45,548	31,915	30,433	32,716
% of consolidated	**54%**	56%	52%	47%	48%	60%
Natural gas (mmcf/d)	**265.51**	266.82	250.33	216.64	198.55	133.24
% of consolidated	**46%**	44%	48%	53%	52%	40%
Total (boe/d)	**97,154**	100,357	87,270	68,021	63,526	54,922

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 Consolidated Interim Financial Statements) and net debt, a measure of capital in accordance with IAS 1 “Presentation of Financial Statements” (please see Capital Disclosures in the Notes to the Consolidated Interim Financial Statements).

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

Acquisitions: The sum of acquisitions from the Consolidated Statements of Cash Flows, Vermilion common shares issued as consideration, the estimated value of contingent consideration, the amount of acquiree's outstanding long-term debt assumed plus or net of acquired working capital deficit or surplus. We believe that including these components provides a useful measure of the economic investment associated with our acquisition activity.

Capital expenditures: The sum of drilling and development and exploration and evaluation from the Consolidated Statements of Cash Flows. We consider capital expenditures to be a useful measure of our investment in our existing asset base. Capital expenditures are also referred to as E&D capital.

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

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

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

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

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

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

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

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

Return on capital employed (ROCE): ROCE is a measure that we use to analyze our profitability and the efficiency of our capital allocation process. ROCE is calculated by dividing net earnings before interest and taxes ("EBIT") by average capital employed over the preceding twelve months. Capital employed is calculated as total assets less current liabilities while average capital employed is calculated using the balance sheets at the beginning and end of the twelve-month period.

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

($M)	Q1 2020	Q4 2019	Q1 2019
Dividends declared	**90,067**	107,702	105,549
Shares issued for the Dividend Reinvestment Plan	**(7,645)**	(10,200)	(7,104)
Net dividends	**82,422**	97,502	98,445
Drilling and development	**227,433**	97,114	197,291
Exploration and evaluation	**6,271**	3,511	4,762
Asset retirement obligations settled	**3,732**	7,352	3,597
Payout	**319,858**	205,479	304,095
% of fund flows from operations	**188%**	95%	120%

('000s of shares)	Q1 2020	Q4 2019	Q1 2019
Shares outstanding	**157,020**	156,290	153,213
Potential shares issuable pursuant to the VIP	**3,405**	3,622	3,437
Diluted shares outstanding	**160,425**	159,912	156,650

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

	Twelve Months Ended	
($M)	Mar 31, 2020	Mar 31, 2019
Net (loss) earnings	**(1,325,252)**	286,457
Taxes	**(180,479)**	100,928
Interest expense	**80,380**	78,150
EBIT	**(1,425,351)**	465,535
Average capital employed	**4,816,006**	4,824,945
Return on capital employed	**(30)%**	10%

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

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Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

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

Stephen P. Larke [4, 6, 12]
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Loren M. Leiker [10]
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Anthony Marino
Calgary, Alberta

Robert Michaleski [4, 5]
Calgary, Alberta

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

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

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

OFFICERS AND KEY PERSONNEL
CANADA

Anthony Marino
President & Chief Executive Officer

Lars Glemser
Vice President & Chief Financial Officer

Mona Jasinski
Executive Vice President, People and Culture

Michael Kaluza
Executive Vice President & Chief Operating Officer

Dion Hatcher
Vice President Canada Business Unit

Terry Hergott
Vice President Marketing

Kyle Preston
Vice President Investor Relations

Jenson Tan
Vice President Business Development

Daniel Goulet
Director Corporate HSE

Jeremy Kalanuk
Director Operations Accounting

Bryce Kremnica
Director Field Operations - Canada Business Unit

Steve Reece
Director Information Technology & Information Systems

Tom Rafter
Director Land - Canada Business Unit

Adam Iwanicki
Director Marketing

Robert (Bob) J. Engbloom
Corporate Secretary

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

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

EUROPE
Gerard Schut
Vice President European Operations

Sylvain Nothhelfer
Managing Director - France Business Unit

Sven Tummers
Managing Director - Netherlands Business Unit

Bill Liutkus
Managing Director - Germany Business Unit

Darcy Kerwin
Managing Director - Ireland Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUSTRALIA
Bruce D. Lake
Managing Director - Australia Business Unit

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Export Development Canada

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

Wells Fargo Bank N.A., Canadian Branch

HSBC Bank Canada

Bank of America N.A., Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Alberta Treasury Branches

Canadian Western Bank

Goldman Sachs Lending Partners LLC

Barclays Bank PLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
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TRANSFER AGENT

Computershare Trust Company of Canada

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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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