Q3 2018

MANAGEMENT'S DISCUSSION AND ANALYSIS

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.

INTERNATIONALLY DIVERSIFIED | SUSTAINABLE GROWTH AND INCOME

VERMILION ENERGY

Front Cover Theme

Sustainability is integrated into every facet of Vermilion's business. This 15-hectare greenhouse is an example of how Vermilion reduces greenhouse emissions with geothermal energy. At Vermilion's production facility in Parentis-en-Born, France, heat from our produced water is transferred to the heating system of the adjacent greenhouse. The result is an economically and ecologically viable greenhouse operation growing tomatoes with heat generated without carbon emissions.

Across the company, Vermilion has decreased our emissions intensity on a per unit of production basis. This is due to our energy efficiency programs, emission reduction initiatives and an operational structure that maximizes production while reducing our footprint and energy consumption intensity.

Read more about Vermilion's renewable energy projects in our Sustainability Report online at www.vermilionenergy.com.

Disclaimer

Certain statements included or incorporated by reference in this document may constitute forward looking statements or financial outlooks under applicable securities legislation. Such forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this document may include, but are not limited to: cash flows and capital expenditures including, without limitation, statements regarding our 2019 budget; business strategies and objectives; future production and production levels (including the timing thereof); permitting, workover and maintenance, exploration and development plans; drilling plans and schedules; the timing of the anticipated closing of the transition of ownership and operatorship of assets from Shell E&P Ireland Limited and the expected impact of that closing; expected benefits of Vermilion's acquisition of assets in the Powder River Basin in Wyoming; acquisition and disposition plans (including the costs, timing and completion thereof); statements regarding our hedging activities and plans; the ability of Vermilion to maintain its current dividend; the incurrence and rate of income taxes; tax pools and future income taxes; statements regarding our ability to finance planned capital expenditures, dividends, and abandonment and reclamation expenditures; and the timing of regulatory proceedings and approvals.

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

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

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

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

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

Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated October 24, 2018, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three and nine months ended September 30, 2018 compared with the corresponding periods in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three and nine months ended September 30, 2018 and the audited consolidated financial statements for the year ended December 31, 2017 and 2016, together with the accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

The unaudited condensed consolidated interim financial statements for the three and nine months ended September 30, 2018 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with IAS 31, "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB").

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

- Fund flows from operations: Fund flows from operations is a measure of profit or loss in accordance with IFRS 8 "Operating Segments". Please see "Segmented information" in the "Notes to the condensed consolidated 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.
- 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).

IFRS 16 Application

In Q3 2018, Vermilion began applying IFRS 16 "Leases" effective January 1, 2018. Q1 2018 and Q2 2018 results have been revised to reflect the impact of this new accounting pronouncement. Please refer to Recently Adopted Accounting Pronouncements for further information.

Guidance

On October 30, 2017, we released our 2018 capital expenditure guidance of $315 million and associated production guidance of between 74,500 to 76,500 boe/d. On January 15, 2018, we increased our capital expenditure guidance to $325 million and production guidance to between 75,000 to 77,500 boe/d to reflect the post-closing impact of the acquisition of a private southeast Saskatchewan and southwest Manitoba light oil producer. On April 16, 2018, we increased our capital expenditure guidance to $430 million and production guidance to between 86,000 to 90,000 boe/d to reflect the post-closing impact of the acquisition of Spartan Energy Corp. On July 30, 2018, we increased our capital expenditure guidance to $500 million to reflect the acceleration of our Australia drilling campaign into Q4 2018, and to a lesser extent to account for the impact of foreign exchange fluctuations on our Canadian dollar capital levels. As of October 25, 2018, we are increasing our capital expenditure guidance to $510 million to reflect additional capital activity associated with the assets acquired in the Powder River Basin in August of 2018.

We released our 2019 capital budget and related guidance concurrent with the release of our Q3 2018 results.

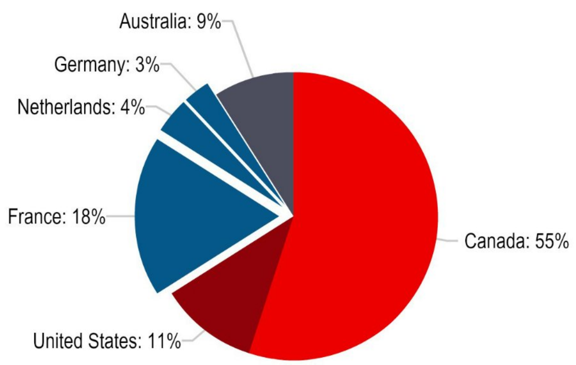
The following table summarizes our guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2018 Guidance			
2018 Guidance	October 30, 2017	315	74,500 to 76,500
2018 Guidance	January 15, 2018	325	75,000 to 77,500
2018 Guidance	April 16, 2018	430	86,000 to 90,000
2018 Guidance	July 30, 2018	500	86,000 to 90,000
2018 Guidance	October 25, 2018	510	86,000 to 90,000
2019 Guidance			
2019 Guidance	October 25, 2018	530	101,000 to 106,000

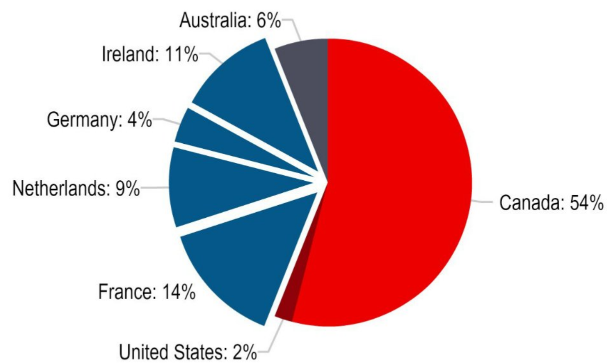
Vermilion's Business

Vermilion is a Calgary, Alberta based international oil and gas producer focused on the acquisition, exploration, development and optimization of producing properties in North America, Europe, and Australia. We manage our business through our Calgary head office and our international business unit offices. This MD&A separately discusses each of our business units in addition to our corporate segment.

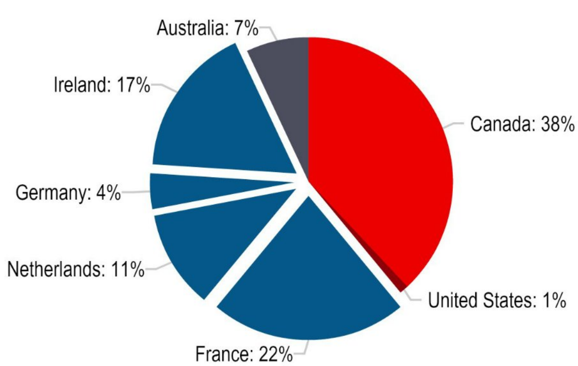
2018 YTD capital expenditures of $355MM by business unit



2018 YTD production of 82,433 boe/d by business unit



2018 YTD fund flows from operations of $616MM by business unit



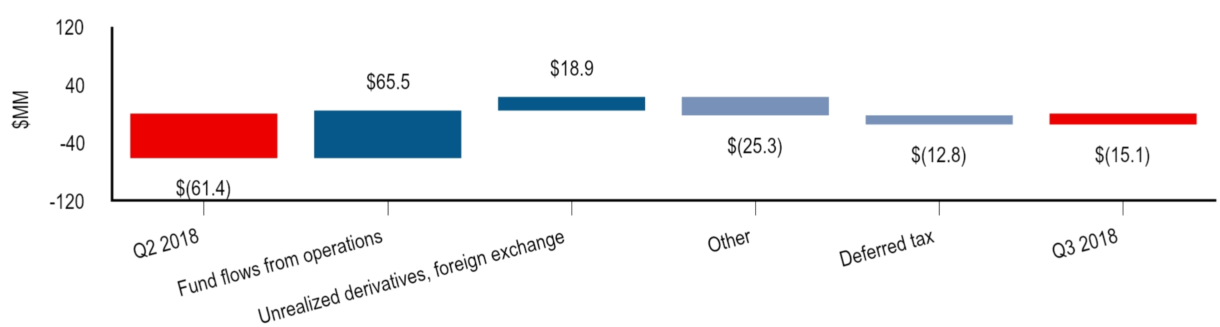
Consolidated Results Overview

	Q3 2018	Q2 2018	Q3 2017	Q3/18 vs. Q2/18	Q3/18 vs. Q3/17	YTD 2018	YTD 2017	2018 vs. 2017
Production								
Crude oil and condensate (bbls/d)	**47,152**	34,574	27,687	36%	70%	**36,318**	27,684	31%
NGLs (bbls/d)	**6,839**	5,651	4,947	21%	38%	**5,878**	3,828	54%
Natural gas (mmcf/d)	**253.38**	242.40	208.63	5%	21%	**241.42**	209.35	15%
Total (boe/d)	**96,222**	80,625	67,403	19%	43%	**82,433**	66,404	24%
Sales								
Crude oil and condensate (bbls/d)	**46,368**	34,655	28,391	34%	63%	**35,749**	27,431	30%
NGLs (bbls/d)	**6,839**	5,651	4,947	21%	38%	**5,878**	3,828	54%
Natural gas (mmcf/d)	**253.38**	242.40	208.63	5%	21%	**241.42**	209.35	15%
Total (boe/d)	**95,437**	80,706	68,107	18%	40%	**81,864**	66,151	24%
Build (draw) in inventory (mbbls)	**73**	(7)	(64)			**155**	69	
Financial metrics								
Fund flows from operations ($M)	**260,705**	195,190	130,755	34%	99%	**616,310**	421,312	46%
Per share ($/basic share)	**1.71**	1.45	1.08	18%	58%	**4.51**	3.51	28%
Net (loss) earnings	**(15,099)**	(61,364)	(39,191)	(75)%	(61)%	**(51,723)**	53,613	N/A
Per share ($/basic share)	**(0.10)**	(0.46)	(0.32)	(78)%	(69)%	**(0.38)**	0.45	N/A
Net debt ($M)	**2,034,086**	1,796,807	1,370,995	13%	48%	**2,034,086**	1,370,995	48%
Cash dividends ($/share)	**0.690**	0.690	0.645	—%	7%	**2.025**	1.935	5%
Activity								
Capital expenditures ($M)	**146,185**	79,984	91,382	83%	60%	**354,634**	246,146	44%
Acquisitions ($M)	**198,173**	1,465,485	20,976			**1,756,736**	24,589	
Gross wells drilled	**65.00**	18.00	17.00			**112.00**	48.00	
Net wells drilled	**58.97**	16.19	13.77			**102.85**	40.58	

Financial performance review

Q3 2018 vs. Q2 2018

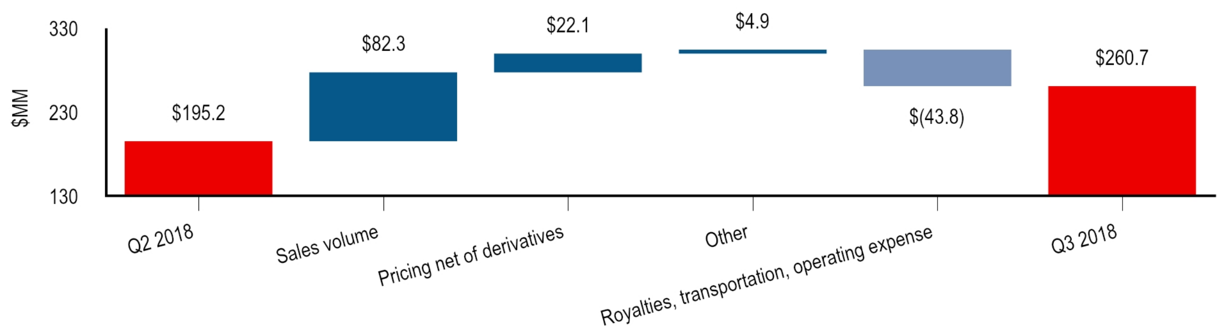
Net loss of $15.1MM in Q3 2018 compared to a net loss of $61.4MM in Q2 2018



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

- We recorded a net loss for Q3 2018 of $15.1 million ($0.10/basic share) compared to a net loss of $61.4 million ($0.46/basic share) in Q2 2018. The net loss in Q3 2018 primarily resulted from a $75.8 million unrealized loss on derivative instruments and a $23.0 million unrealized loss on foreign exchange. The decrease in the net loss in Q3 2018 compared to Q2 2018 was primarily attributable to a $65.5 million increase in fund flows from operations and a $29.5 million decrease in the unrealized loss on derivative instruments.

34% increase in fund flows from operations from Q2 2018 to Q3 2018

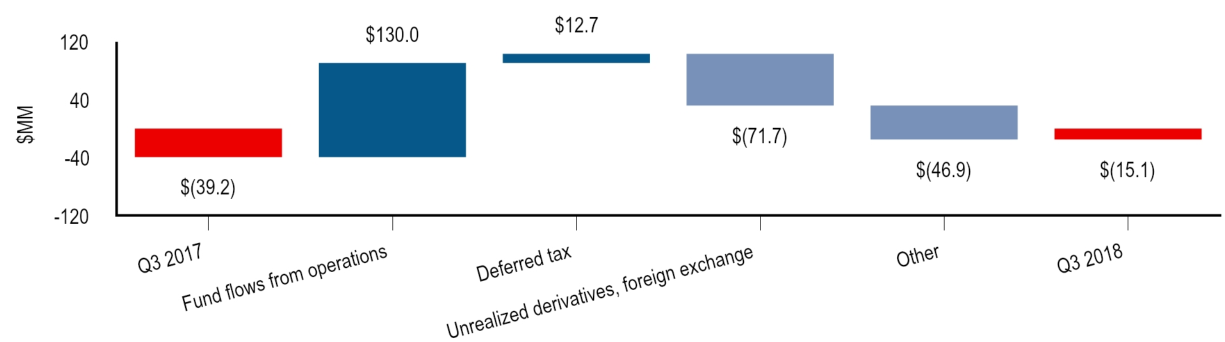


"Other" contains general and administration, corporate income taxes, interest, realized foreign exchange, and realized other

- Generated fund flows from operations of $260.7 million during Q3 2018, an increase of 34% from Q2 2018. This quarter-over-quarter increase was due to a full quarter of contribution from Spartan Energy Corp. ("Spartan") following the Q2 2018 acquisition and stronger European natural gas and North American crude oil pricing.

Q3 2018 vs. Q3 2017

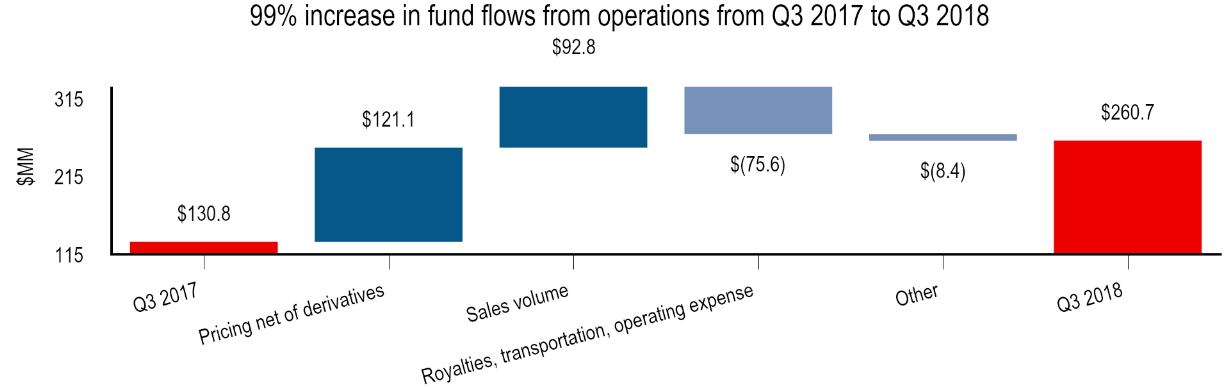
Net loss of $15.1MM in Q3 2018 compared to a net loss of $39.2 million in Q3 2017



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

- We recorded a net loss for Q3 2018 of $15.1 million ($0.10/basic share) compared to a net loss of $39.2 million ($0.32/basic share) in Q3 2017 . This net loss occurred despite a doubling in fund flows from operations due to unrealized losses on derivatives and foreign exchange (approximately $68.8 million after-tax impact).

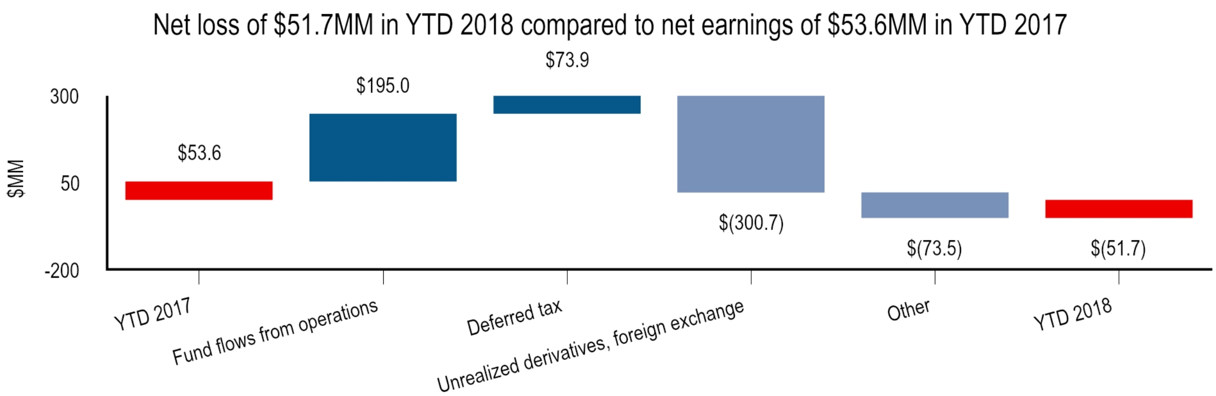
99% increase in fund flows from operations from Q3 2017 to Q3 2018



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

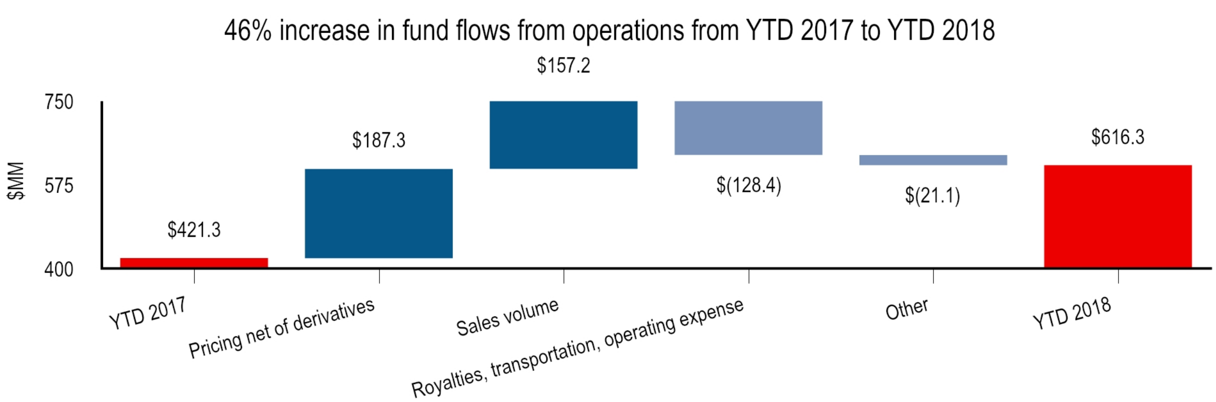
- Fund flows from operations doubled in Q3 2018 versus Q3 2017 and increased by nearly 60% on a per share basis. This increase was due to an increase in our realized pricing and higher sales volumes. Our consolidated realized price increased by 46% from $39.66/boe to $57.90/boe due to an increase in our relative oil production and significantly stronger crude oil and European gas pricing while our sales volumes increased by 40% due to the Spartan acquisition and organic production growth.

YTD 2018 vs. YTD 2017



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

- For the nine months ended September 30, 2018, the net loss of $51.7 million compared to net earnings of $53.6 million for the comparative year-to-date period in the prior year. The net loss primarily resulted from an unrealized loss on derivative instruments of $163.8 million (compared to an unrealized gain of $79.0 million in the prior year) and an unrealized loss on foreign exchange of $26.9 million (compared to an unrealized gain of $31.1 million in the prior year). These unrealized losses were partially offset by a year-over-year increase in fund flows from operations of $195.0 million.



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

- Fund flows from operations increased 46% for the nine months ended September 30, 2018 versus the comparable period in the prior year due to higher realized pricing and increased sales volumes. Our consolidated realized price increased by 26% from $43.27/boe to $54.64/boe due to an increase in our relative oil production and significantly stronger crude oil and European gas pricing while our sales volumes increased by nearly 25% due to production increases in Canada, the Netherlands, and the United States.
- On a per unit basis, fund flows from operations increased by 18% from $23.34/boe in the nine months ended September 30, 2017 to $27.59/boe in 2018. This increase reflects a significant improvement in our realized price per boe and includes an 18% decrease in per boe general and administration expenses as our overall expense increased by only 2% despite significant production growth. These decreases were partially offset by higher per unit costs for royalties (resulting from the stronger commodity price environment and higher royalty rates on the Spartan assets) and operating expenses. Per boe operating expenses increased by $1.14/boe from $9.80/boe in 2017 to $10.94/boe in 2018 due in part to a stronger Euro in the current year (approximately $0.22/boe increase) and increased expenses associated with higher value oil production in Canada.

Production review

Q3 2018 vs. Q2 2018

- Consolidated average production of 96,222 boe/d during Q3 2018 increased 19% versus Q2 2018. The increase in production was primarily attributable to a full quarter of contribution from the Spartan assets acquired in May of 2018, growth in the United States, and well workovers in Australia. These production increases were partially offset by a 9% decrease in Ireland, including a 450 boe/d decrease due to planned downtime.

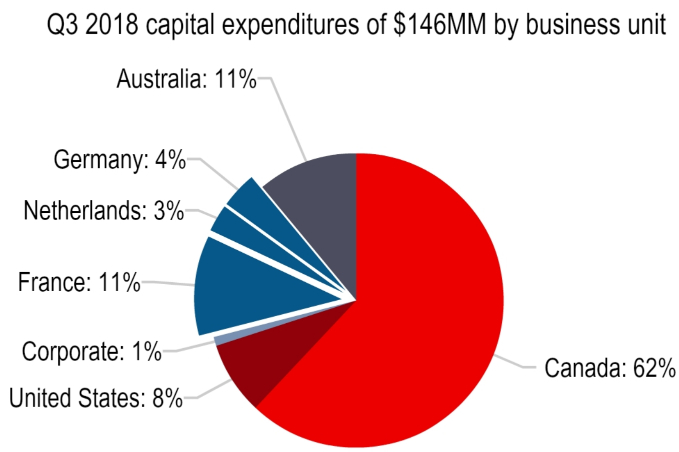
Q3 2018 vs. Q3 2017

- Consolidated average production of 96,222 boe/d in Q3 2018 represented an increase of 43% from Q3 2017. Year-over-year production was higher due to growth in Canada, the United States, and the Netherlands. In Canada, year-over-year growth was the result of both acquisitions and continued development of our Mannville condensate-rich resource play. In the United States, production growth resulted from an acquisition in the current quarter and organic drilling activity. In the Netherlands, year-over-year growth occurred following the receipt of production permits (the absence of which restricted production from certain wells in the prior year).

YTD 2018 vs. YTD 2017

- For the nine months ended September 30, 2018, consolidated average production of 82,433 boe/d represented an increase of 24% from the comparable period in 2017 due to production growth in Canada and the Netherlands. In Canada, production increased by 16,164 boe/d, largely due to contributions from acquisitions and continued development of our Mannville condensate-rich resource play. In the Netherlands, year-over-year production growth occurred following the receipt of production permits (the absence of which restricted production from certain wells in the comparable period in 2017).

Activity review



- For the three months ended September 30, 2018, capital expenditures of $146.2 million primarily related to activity in Canada, Australia, and France. In Canada, capital expenditures of $89.8 million included the drilling of 65.0 (59.0 net) wells, primarily in southeast Saskatchewan. In Australia, capital expenditures of $16.1 million primarily related to well workover activity and expenditures incurred in preparation for the Q4 2018 drilling program. In France, capital expenditures of $15.8 million primarily related to subsurface and workover programs.

Sustainability review

Dividends

- Declared dividends of $0.23 per common share per month for Q3 2018, resulting in total dividends declared of $2.025 per common share for the nine months ended September 30, 2018.
- In Q2 2018, we increased our monthly dividend by 7% resulting in a year-over-year increase in cash dividends. The Q2 2018 increase was our fourth dividend increase (previously Vermilion's distribution in the income trust era) since we began paying a distribution in 2003.

Net debt

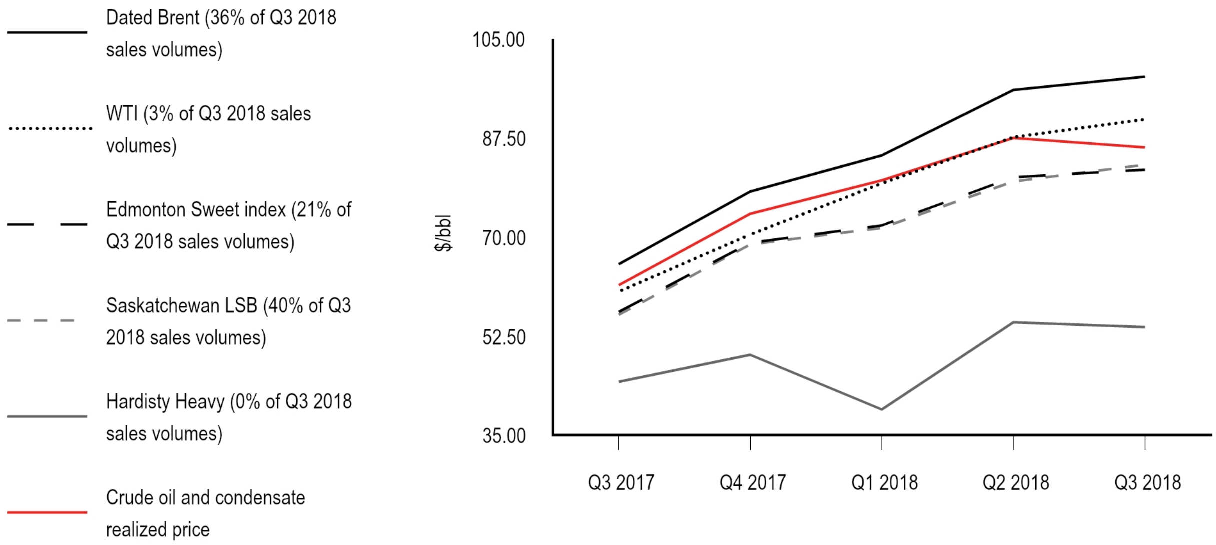
- Net debt increased to $2.03 billion as at September 30, 2018 from $1.37 billion at December 31, 2017, and was primarily due to acquisition activity in 2018 and an increase in net current derivative liability to $161.1 million as at September 30, 2018 (compared to $60.9 million as at December 31, 2017).

Commodity Prices

	Q3 2018	Q2 2018	Q3 2017	Q3/18 vs. Q2/18	Q3/18 vs. Q3/17	YTD 2018	YTD 2017	2018 vs. 2017
Crude oil								
WTI ($/bbl)	**90.83**	87.63	60.37	4%	50%	**85.95**	64.64	33%
WTI (US $/bbl)	**69.50**	67.88	48.20	2%	44%	**66.75**	49.47	35%
Edmonton Sweet index ($/bbl)	**81.92**	80.60	56.76	2%	44%	**78.14**	60.85	28%
Edmonton Sweet index (US $/bbl)	**62.68**	62.43	45.32	—%	38%	**60.69**	46.57	30%
Saskatchewan LSB index ($/bbl)	**82.79**	79.84	56.25	4%	47%	**78.04**	59.82	30%
Saskatchewan LSB index (US $/bbl)	**63.35**	61.84	44.91	2%	41%	**60.61**	45.78	32%
Dated Brent ($/bbl)	**98.37**	95.99	65.22	2%	51%	**92.87**	67.82	37%
Dated Brent (US $/bbl)	**75.27**	74.35	52.08	1%	45%	**72.13**	51.90	39%
Hardisty Heavy ($/bbl)	**54.11**	54.92	44.41	(1)%	22%	**49.44**	44.47	11%
Hardisty Heavy (US $/bbl)	**41.40**	42.54	35.46	(3)%	17%	**38.40**	34.03	13%
Natural gas								
AECO ($/mmbtu)	**1.19**	1.18	1.45	1%	(18)%	**1.48**	2.31	(36)%
NBP ($/mmbtu)	**10.95**	9.42	6.78	16%	62%	**10.12**	7.10	43%
NBP (€/mmbtu)	**7.20**	6.12	4.61	18%	56%	**6.58**	4.88	35%
TTF ($/mmbtu)	**10.92**	9.50	6.93	15%	58%	**10.00**	7.12	40%
TTF (€/mmbtu)	**7.18**	6.17	4.71	16%	52%	**6.50**	4.90	33%
Henry Hub ($/mmbtu)	**3.80**	3.61	3.76	5%	1%	**3.74**	4.14	(10)%
Henry Hub (US $/mmbtu)	**2.90**	2.80	3.00	4%	(3)%	**2.90**	3.17	(9)%
Average exchange rates								
CDN $/US $	**1.31**	1.29	1.25	2%	5%	**1.29**	1.31	(2)%
CDN $/Euro	**1.52**	1.54	1.47	(1)%	3%	**1.54**	1.45	6%
Realized Prices								
Crude oil and condensate ($/bbl)	**85.84**	87.50	61.47	(2)%	40%	**84.98**	64.58	32%
NGLs ($/bbl)	**27.97**	26.06	23.96	7%	17%	**26.61**	23.01	16%
Natural gas ($/mmbtu)	**5.35**	4.77	4.01	12%	33%	**5.30**	4.79	11%
Total ($/boe)	**57.90**	53.72	39.66	8%	46%	**54.64**	43.27	26%

Crude oil

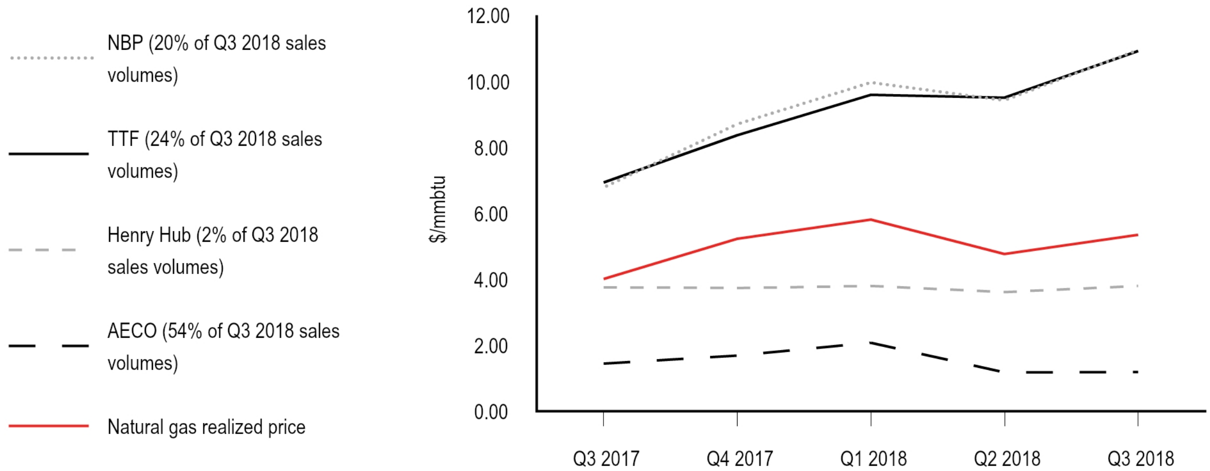
Realized crude oil and condensate price was a 5% premium to the Edmonton Sweet index during Q3 2018



- Although largely unchanged for the three months ending September 30, 2018 compared to the second quarter of 2018, crude oil prices were volatile during Q3 2018, with prices falling throughout the first half of the quarter before rallying higher into the second half of the quarter. The primary drivers of the price volatility were global macro concerns stemming from trade conflict and global supply uncertainty.
- For the three months ending September 30, 2018, WTI in Canadian dollar terms increased 4% quarter-over-quarter and 50% year-over-year. Similarly, in Q3 2018, Dated Brent prices in Canadian dollar terms increased 2% quarter-over-quarter and 51% year-over year.
- Western Canadian takeaway capacity constraints impacted heavy crude prices much more than Edmonton Sweet and Saskatchewan LSB prices, with Hardisty prices averaging 1% lower quarter-over-quarter versus the 2% and 4% quarter-over-quarter gains for Edmonton Sweet and Saskatchewan LSB, respectively.
- Vermilion's crude oil production benefits from light oil pricing and no exposure to significantly discounted heavy crude oil. Approximately 36% of our Q3 2018 crude oil and condensate production was priced at the Dated Brent index (which averaged a premium to WTI of US$5.77) while the remainder of our crude oil and condensate production was priced at the Edmonton Sweet, Saskatchewan LSB, and WTI indices. As a result, our Q3 2018 crude oil and condensate realized price of $85.84 was a 59% premium to Hardisty Heavy.

Natural gas

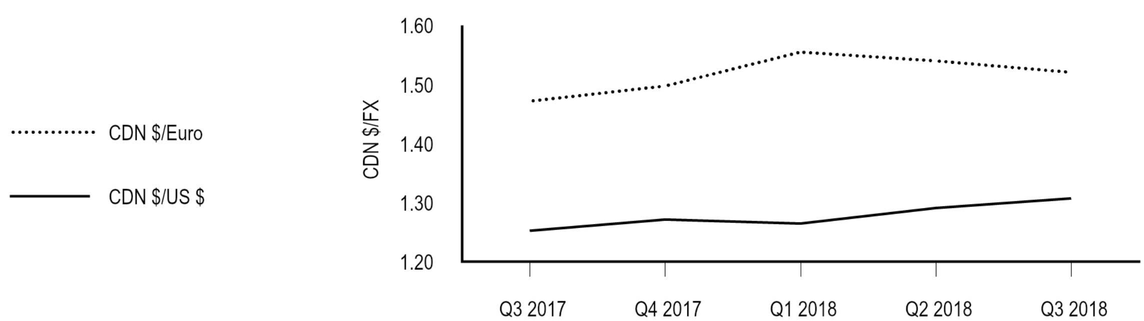
Realized natural gas price was a $4.16/mmbtu premium to AECO during Q3 2018



- European natural gas prices increased significantly in Q3 2018 versus all comparable periods, rising to multi-year highs as increasingly favourable supply and demand conditions were driven by growing competition from Asia for LNG supply, strong demand from storage, surging carbon prices in the European Union, and maintenance impacting Norwegian and Russian supplies.
- As a result of favourable market conditions, TTF and NBP in Canadian dollar terms increased 15% and 16% quarter-over-quarter. Year-over-year, TTF and NBP increased 58% and 62% in Canadian dollar terms versus Q3 2017.
- Natural gas prices at AECO increased 1% in Q3 2018 as compared to Q2 2018. While the AECO gas market continues to face egress challenges, access to storage and stronger domestic gas demand were able to mitigate some of the impact.
- For Q3 2018, average European gas prices represented a $9.75/mmbtu premium to AECO and a $7.14/mmbtu premium to Henry Hub pricing. Approximately 44% of our natural gas production in Q3 2018 benefited from this premium European pricin

Foreign exchange

Euro weakened 1% versus the Canadian dollar quarter-over-quarter



- In the three months ended September 30, 2018, the Canadian dollar weakened slightly against the US dollar quarter-over-quarter.
- Despite the Canadian dollar weakening against the US dollar in Q3 2018, the Canadian dollar strengthened slightly against the Euro as compared to Q2 2018.

Canada Business Unit

Overview

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

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

Operational and financial review

Canada business unit ($M except as indicated)	Q3 2018	Q2 2018	Q3 2017	Q3/18 vs. Q2/18	Q3/18 vs. Q3/17	YTD 2018	YTD 2017	2018 vs. 2017
Production and sales								
Crude oil and condensate (bbls/d)	**28,477**	17,009	9,288	67%	207%	**18,323**	8,831	107%
NGLs (bbls/d)	**6,126**	5,589	4,891	10%	25%	**5,611**	3,776	49%
Natural gas (mmcf/d)	**136.77**	127.32	103.92	7%	32%	**123.54**	94.52	31%
Total (boe/d)	**57,397**	43,817	31,499	31%	82%	**44,524**	28,360	57%
Production mix (% of total)								
Crude oil and condensate	**50%**	39%	29%			**41%**	31%	
NGLs	**10%**	13%	16%			**13%**	13%	
Natural gas	**40%**	48%	55%			**46%**	56%	
Activity								
Capital expenditures	**89,837**	28,694	43,746	213%	105%	**187,646**	121,802	54%
Acquisitions	**6,146**	1,465,335	19,712			**1,561,731**	21,223	
Gross wells drilled	**65.00**	18.00	15.00			**101.00**	38.00	
Net wells drilled	**58.97**	16.19	12.75			**91.85**	31.56	
Financial results								
Sales	**243,016**	148,915	77,238	63%	215%	**484,864**	236,381	105%
Royalties	**(33,801)**	(15,463)	(6,653)	119%	408%	**(59,112)**	(23,957)	147%
Transportation	**(9,057)**	(5,186)	(4,485)	75%	102%	**(18,783)**	(12,532)	50%
Operating	**(55,577)**	(35,762)	(22,071)	55%	152%	**(115,435)**	(58,088)	99%
General and administration	**(1,316)**	(1,891)	(2,239)	(30)%	(41)%	**(3,907)**	(7,064)	(45)%
Fund flows from operations	**143,265**	90,613	41,790	58%	243%	**287,627**	134,740	113%
Netbacks ($/boe)								
Sales	**46.02**	37.35	26.65	23%	73%	**39.89**	30.53	31%
Royalties	**(6.40)**	(3.88)	(2.30)	65%	178%	**(4.86)**	(3.09)	57%
Transportation	**(1.72)**	(1.30)	(1.55)	32%	11%	**(1.55)**	(1.62)	(4)%
Operating	**(10.52)**	(8.97)	(7.62)	17%	38%	**(9.50)**	(7.50)	27%
General and administration	**(0.25)**	(0.47)	(0.77)	(47)%	(68)%	**(0.32)**	(0.91)	(65)%
Fund flows from operations netback	**27.13**	22.73	14.41	19%	88%	**23.66**	17.41	36%
Realized prices								
Crude oil and condensate ($/bbl)	**79.86**	79.43	57.15	1%	40%	**78.92**	61.26	29%
NGLs ($/bbl)	**27.82**	26.00	23.93	7%	16%	**26.47**	23.04	15%
Natural gas ($/mmbtu)	**1.44**	1.09	1.84	32%	(22)%	**1.47**	2.51	(41)%
Total ($/boe)	**46.02**	37.35	26.65	23%	73%	**39.89**	30.53	31%
Reference prices								
WTI (US $/bbl)	**69.50**	67.88	48.20	2%	44%	**66.75**	49.47	35%
Edmonton Sweet index ($/bbl)	**81.92**	80.60	56.76	2%	44%	**78.14**	60.85	28%
Saskatchewan LSB index ($/bbl)	**82.79**	79.84	56.25	4%	47%	**78.04**	59.82	30%
AECO ($/mmbtu)	**1.19**	1.18	1.45	1%	(18)%	**1.48**	2.31	(36)%

Production

- Q3 2018 average production increased 31% from the prior quarter and 82% year-over-year primarily due to a full quarter of production contribution from the assets acquired with Spartan. Production was partially offset by downtime due to third party gas plant maintenance, delayed regulatory approvals to produce certain wells at full capacity, and weather-related project delays.
- Mannville production averaged approximately 21,000 boe/d in Q3 2018, a decrease of 3% quarter-over-quarter.
- Cardium production averaged approximately 4,700 boe/d in Q3 2018, a decrease of 4% quarter-over-quarter.
- Our southeast Saskatchewan assets produced an average of approximately 24,700 boe/d in Q3 2018 as compared to 11,000 boe/d in Q2 2018 primarily due to the Spartan acquisition.

Activity review

- Vermilion drilled 60 (57.1 net) operated wells and participated in the drilling of five (1.9 net) non-operated wells in Canada during Q3 2018.

  Alberta
  - In Q3 2018, we drilled or participated in four (4.0 net) operated and one (0.4 net) non-operated wells, completed three (3.0 net) operated and one (0.3 net) non-operated wells and brought on production five (5.0 net) operated Mannville wells.
  - In 2018, we plan to drill or participate in 18 (17.3 net) Mannville wells.

  Saskatchewan
  - In Q3 2018, we drilled or participated in 56 (53.1 net) operated wells and four (1.5 net) non-operated wells, 46 (43.2 net) operated and four (1.5 net) non-operated of which were drilled from inventory acquired with Spartan. We also completed 58 (55.0 net) wells and brought 48 (44.8 net) wells on production.
  - In 2018, we plan to drill or participate in 117 (105.7 net) wells in Saskatchewan.

- On May 28, 2018, Vermilion acquired 100% of the issued and outstanding common shares of Spartan, a publicly traded southeast Saskatchewan oil and gas producer. Consideration consisted of the issuance of 27.9 million Vermilion common shares valued at approximately $1.2 billion (based on the closing price per Vermilion common share of $44.30 on the Toronto Stock Exchange on May 28, 2018). Vermilion also assumed approximately $172 million of Spartan's outstanding debt at the time the transaction closed.

Sales

- The realized price for our crude oil and condensate production in Canada is linked to WTI subject to market conditions in western Canada (as reflected by the Saskatchewan LSB index price in Saskatchewan and the Edmonton Sweet index price in Alberta). The realized price of our natural gas in Canada is based on the AECO index in Canada.
- Q3 2018 sales per boe increased 23% compared to Q2 2018 despite relatively flat North American gas and crude oil prices due to an increase in our production weighting towards higher-priced crude oil and condensate production. Quarter-over-quarter, our crude oil and condensate production mix increased from 39% of Canadian production to 50% of Canadian production.
- For the three and nine months ended September 30, 2018, sales per boe increased versus the comparable periods in the prior year due to increased Edmonton Sweet index and Saskatchewan LSB pricing coupled with an increased weighting towards higher-priced crude oil and condensate production.

Royalties

- Royalties as a percentage of sales for the three and nine months ended September 30, 2018 of 13.9% and 12.2%, respectively, increased from the comparable periods in 2017 due to the impact of the Spartan assets, which have higher associated royalty rates, and also due to higher commodity prices on the sliding scale used to determine royalty rates.

Transportation

- Q3 2018 transportation expense on a per unit basis increased versus Q2 2018 and Q3 2017 due to an increase in production that incurs higher transportation expense.
- For the nine months ended September 30, 2018, transportation expense on a per unit basis was relatively consistent with the comparable period in 2017.

Operating

- For the three and nine months ended September 30, 2018, operating expense increased on both a dollar and per unit basis versus all comparable periods. On a dollar basis, the increase in operating expense was driven by higher production volumes, but was partially offset by the impact of higher volumes on fixed costs. On a per unit basis, the increase in operating expense was primarily attributable to the impact of a full quarter of production from the Spartan assets, which have higher associated per unit operating expense than our legacy assets.

France Business Unit

Overview

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

Operational and financial review

France business unit ($M except as indicated)	Q3 2018	Q2 2018	Q3 2017	Q3/18 vs. Q2/18	Q3/18 vs. Q3/17	YTD 2018	YTD 2017	2018 vs. 2017
Production								
Crude oil (bbls/d)	**11,407**	11,683	10,918	(2)%	4%	**11,377**	11,040	3%
Sales								
Crude oil (bbls/d)	**11,482**	11,682	11,360	(2)%	1%	**11,025**	10,799	2%
Inventory (mbbls)								
Opening crude oil inventory	**300**	300	254			**197**	148	
Crude oil production	**1,049**	1,063	1,004			**3,106**	3,014	
Crude oil sales	**(1,056)**	(1,063)	(1,044)			**(3,010)**	(2,948)	
Closing crude oil inventory	**293**	300	214			**293**	214	
Activity								
Capital expenditures	**15,779**	17,044	15,756	(7)%	—%	**62,750**	53,354	18%
Gross wells drilled	**—**	—	—			**5.00**	5.00	
Net wells drilled	**—**	—	—			**5.00**	5.00	
Financial results								
Sales	**100,840**	101,128	66,100	—%	53%	**274,713**	189,325	45%
Royalties	**(12,765)**	(12,602)	(6,399)	1%	99%	**(34,805)**	(17,966)	94%
Transportation	**(2,013)**	(2,813)	(3,434)	(28)%	(41)%	**(7,184)**	(10,152)	(29)%
Operating	**(13,733)**	(13,893)	(13,148)	(1)%	4%	**(40,675)**	(36,670)	11%
General and administration	**(3,365)**	(3,500)	(2,543)	(4)%	32%	**(10,378)**	(9,326)	11%
Current income taxes	**(6,913)**	(5,234)	(1,396)	32%	395%	**(14,200)**	(8,208)	73%
Fund flows from operations	**62,051**	63,086	39,180	(2)%	58%	**167,471**	107,003	57%
Netbacks ($/boe)								
Sales	**95.46**	95.13	63.24	—%	51%	**91.27**	64.22	42%
Royalties	**(12.08)**	(11.85)	(6.12)	2%	97%	**(11.56)**	(6.09)	90%
Transportation	**(1.91)**	(2.65)	(3.29)	(28)%	(42)%	**(2.39)**	(3.44)	(31)%
Operating	**(13.00)**	(13.07)	(12.58)	(1)%	3%	**(13.51)**	(12.44)	9%
General and administration	**(3.19)**	(3.29)	(2.43)	(3)%	31%	**(3.45)**	(3.16)	9%
Current income taxes	**(6.54)**	(4.92)	(1.34)	33%	388%	**(4.72)**	(2.78)	70%
Fund flows from operations netback	**58.74**	59.35	37.48	(1)%	57%	**55.64**	36.31	53%
Reference prices								
Dated Brent (US $/bbl)	**75.27**	74.35	52.08	1%	45%	**72.13**	51.90	39%
Dated Brent ($/bbl)	**98.37**	95.99	65.22	2%	51%	**92.87**	67.82	37%

Production

- Q3 2018 production decreased 2% from the prior quarter due to natural declines and higher than anticipated well downtime. Production increased 4% year-over-year primarily due to production additions from our Q1 2018 drilling program.

Activity review

- We have completed our 2018 drilling program, which included the drilling and completion of two (2.0 net) Neocomian wells and three (3.0 net) Champotran wells.
- In addition to the drilling and completion activity, we plan to continue our workover and optimization programs in the Aquitaine and Paris Basins throughout 2018.

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Q3 2018 sales per boe was relatively consistent with Q2 2018.
- For the three and nine months ended September 30, 2018, the increase in sales per boe was consistent with increases in the Dated Brent benchmark price.

Royalties

- Royalties in France relate to two components: RCDM (levied on units of production and not subject to changes in commodity prices) and R31 (based on a percentage of sales).
- Royalties as a percentage of sales of 12.7% was relatively consistent with Q2 2018 (12.5%).
- For the three and nine months ended September 30, 2018, royalties as a percentage of sales of 12.7% increased from 9.7% and 9.5% in the respective comparable periods in the prior year due to the impact of a royalty rate increase enacted in 2017.

Transportation

- Transportation expense decreased in Q3 2018 compared to Q2 2018 due to the impact of a prior period adjustment recorded in the current quarter.
- Transportation expense for the three and nine months ended September 30, 2018 decreased versus the comparable periods in the prior year, primarily due to the impact of IFRS 16 adoption in the current year. Please refer to "Recently Adopted Accounting Pronouncements" for additional information.

Operating

- Operating expense in Q3 2018 was relatively consistent with Q2 2018 and Q3 2017 on both a dollar and per unit basis.
- For the nine months ended September 30, 2018, the increase in operating expense on both a dollar and per unit basis was primarily due to the impact of a stronger Euro versus the Canadian dollar and the timing of field activities.

General and administration

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

Current income taxes

- In France, current income taxes are applied to taxable income, after eligible deductions, at a statutory rate of 34.4%.
- 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 2018, the effective rate on current taxes, inclusive of corporate allocations, is expected to be between 10% to 14% of pre-tax fund flows from operations. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- On December 21, 2017, the French Parliament approved the Finance Bill for 2018. The Finance Bill for 2018 provides for a progressive decrease of the French corporate income tax rate from 34.4% to 25.8% by 2022, with the first reduction planned for 2019 to 32.0%.

Netherlands Business Unit

Overview

- Entered the Netherlands in 2004.
- Second largest onshore operator.
- Interests include 25 onshore licenses (all operated) and one offshore license (non-operated).
- Licenses include more than 800,000 net acres of land, 95% of which is undeveloped.

Operational and financial review

Netherlands business unit ($M except as indicated)	Q3 2018	Q2 2018	Q3 2017	Q3/18 vs. Q2/18	Q3/18 vs. Q3/17	YTD 2018	YTD 2017	2018 vs. 2017
Production and sales								
Condensate (bbls/d)	**84**	87	74	(3)%	14%	**83**	85	(2)%
Natural gas (mmcf/d)	**44.37**	43.49	34.90	2%	27%	**44.21**	35.45	25%
Total (boe/d)	**7,479**	7,335	5,890	2%	27%	**7,452**	5,992	24%
Activity								
Capital expenditures	**5,056**	6,695	11,590	(24)%	(56)%	**15,029**	19,275	(22)%
Acquisitions	**2,874**	139	14			**5,773**	14	
Gross wells drilled	**—**	—	2.00			**—**	2.00	
Net wells drilled	**—**	—	1.02			**—**	1.02	
Financial results								
Sales	**41,793**	35,000	21,258	19%	97%	**112,979**	67,146	68%
Royalties	**(1,049)**	(745)	(360)	41%	191%	**(2,644)**	(1,075)	146%
Operating	**(5,812)**	(6,419)	(4,498)	(9)%	29%	**(19,916)**	(14,231)	40%
General and administration	**(320)**	(145)	(510)	121%	(37)%	**(1,238)**	(1,666)	(26)%
Current income taxes	**1,729**	(4,993)	(1,983)	N/A	N/A	**(9,069)**	(3,644)	149%
Fund flows from operations	**36,341**	22,698	13,907	60%	161%	**80,112**	46,530	72%
Netbacks ($/boe)								
Sales	**60.74**	52.43	39.23	16%	55%	**55.54**	41.04	35%
Royalties	**(1.52)**	(1.12)	(0.66)	36%	130%	**(1.30)**	(0.66)	97%
Operating	**(8.45)**	(9.62)	(8.30)	(12)%	2%	**(9.79)**	(8.70)	13%
General and administration	**(0.47)**	(0.22)	(0.94)	114%	(50)%	**(0.61)**	(1.02)	(40)%
Current income taxes	**2.51**	(7.48)	(3.66)	N/A	N/A	**(4.46)**	(2.23)	100%
Fund flows from operations netback	**52.81**	33.99	25.67	55%	106%	**39.38**	28.43	39%
Realized prices								
Condensate ($/bbl)	**82.32**	79.40	52.10	4%	58%	**77.08**	52.92	46%
Natural gas ($/mmbtu)	**10.08**	8.68	6.51	16%	55%	**9.22**	6.81	35%
Total ($/boe)	**60.74**	52.43	39.23	16%	55%	**55.54**	41.04	35%
Reference prices								
TTF ($/mmbtu)	**10.92**	9.50	6.93	15%	58%	**10.00**	7.12	40%
TTF (€/mmbtu)	**7.18**	6.17	4.71	16%	52%	**6.50**	4.90	33%

Production

- Q3 2018 production was relatively consistent with the prior quarter. During the quarter, we brought the Eesveen-02 well (60% working interest) on production and the well is currently flowing at a restricted rate of 10 mmcf/d net. Production increased 27% year-over-year as various permitting delays restricted production through the first nine months of 2017.

Activity review

- Our Q3 2018 capital activity was primarily focused on bringing the Eesveen-02 well on production in addition to planned workovers and facilities maintenance.

Sales

- The price of our natural gas in the Netherlands is based on the TTF index.
- For the three and nine months ended September 30, 2018, sales per boe increased versus all comparable periods, consistent with increases in the TTF reference price.

Royalties

- In the Netherlands, certain wells are subject to overriding royalties as well as royalties that take effect only when specified production levels are exceeded. As such, fluctuations in royalty expense in the periods presented result from the amount of production from those wells. Royalties in Q3 2018 represented less than 3% of sales.

Transportation

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

Operating

- Q3 2018 operating expense decreased in both a dollar and per unit basis versus Q2 2018 due to due to lower activity levels in the current quarter and the implementation of various cost efficiencies.
- For the three and nine months ended September 30, 2018, operating expense increased in a dollar basis versus the comparable periods in the prior year, consistent with higher production volumes. For the nine months ended September 30, 2018, the increase in operating expense on a per unit basis is due primarily to higher electricity costs in the current year.

General and administration

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

Current income taxes

- In the Netherlands, current income taxes are applied to taxable income, after eligible deductions and a 10% uplift deduction applied to operating expenses, eligible G&A 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 2018, the effective rate on current taxes, inclusive of corporate allocations, is expected to be between 10% to 14% of pre-tax fund flows from operations. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.

Germany Business Unit

Overview

- Entered Germany in 2014 through the acquisition of a non-operated natural gas producing property.
- Executed a significant exploration license farm-in agreement in 2015 and acquired operated producing properties in 2016.
- Producing assets consist of seven gas and five oil producing fields with extensive infrastructure in place.
- Significant land position of approximately 1.3 million net acres (97% undeveloped).

Operational and financial review

Germany business unit ($M except as indicated)	Q3 2018	Q2 2018	Q3 2017	Q3/18 vs. Q2/18	Q3/18 vs. Q3/17	YTD 2018	YTD 2017	2018 vs. 2017
Production								
Crude oil (bbls/d)	**1,019**	1,008	1,054	1%	(3)%	**1,035**	1,030	—%
Natural gas (mmcf/d)	**14.88**	14.63	20.12	2%	(26)%	**15.23**	19.79	(23)%
Total (boe/d)	**3,498**	3,447	4,407	1%	(21)%	**3,573**	4,329	(17)%
Sales								
Crude oil (bbls/d)	**929**	1,058	1,067	(12)%	(13)%	**1,097**	993	10%
Natural gas (mmcf/d)	**14.88**	14.63	20.12	2%	(26)%	**15.23**	19.79	(23)%
Total (boe/d)	**3,408**	3,497	4,420	(3)%	(23)%	**3,635**	4,292	(15)%
Production mix (% of total)								
Crude oil	**29%**	29%	24%			**29%**	24%	
Natural gas	**71%**	71%	76%			**71%**	76%	
Activity								
Capital expenditures	**6,497**	2,314	3,020	181%	115%	**11,226**	4,252	164%
Acquisitions	**959**	—	—			**959**	—	
Financial results								
Sales	**21,052**	18,999	15,663	11%	34%	**60,552**	49,798	22%
Royalties	**(2,448)**	(1,251)	(2,261)	96%	8%	**(5,436)**	(4,857)	12%
Transportation	**(1,191)**	(1,779)	(1,603)	(33)%	(26)%	**(4,968)**	(5,043)	(1)%
Operating	**(4,863)**	(5,384)	(3,477)	(10)%	40%	**(16,433)**	(14,151)	16%
General and administration	**(2,073)**	(1,462)	(1,708)	42%	21%	**(5,093)**	(5,687)	(10)%
Fund flows from operations	**10,477**	9,123	6,614	15%	58%	**28,622**	20,060	43%
Netbacks ($/boe)								
Sales	**67.15**	59.69	38.52	12%	74%	**61.02**	42.50	44%
Royalties	**(7.81)**	(3.93)	(5.56)	99%	40%	**(5.48)**	(4.15)	32%
Transportation	**(3.80)**	(5.59)	(3.94)	(32)%	(4)%	**(5.01)**	(4.30)	17%
Operating	**(15.51)**	(16.92)	(8.55)	(8)%	81%	**(16.56)**	(12.08)	37%
General and administration	**(6.61)**	(4.59)	(4.20)	44%	57%	**(5.13)**	(4.85)	6%
Fund flows from operations netback	**33.42**	28.66	16.27	17%	105%	**28.84**	17.12	68%
Realized prices								
Crude oil ($/bbl)	**92.45**	91.00	55.95	2%	65%	**86.71**	60.79	43%
Natural gas ($/mmbtu)	**9.61**	7.68	5.50	25%	75%	**8.32**	6.17	35%
Total ($/boe)	**67.15**	59.69	38.52	12%	74%	**61.02**	42.50	44%
Reference prices								
Dated Brent (US $/bbl)	**75.27**	74.35	52.08	1%	45%	**72.13**	51.90	39%
Dated Brent ($/bbl)	**98.37**	95.99	65.22	2%	51%	**92.87**	67.82	37%
TTF ($/mmbtu)	**10.92**	9.50	6.93	15%	58%	**10.00**	7.12	40%
TTF (€/mmbtu)	**7.18**	6.17	4.71	16%	52%	**6.50**	4.90	33%

Production

- Q3 2018 production was relatively consistent quarter-over-quarter as less downtime at a non-operated gas processing facility was offset by other minor unplanned downtime events. Production decreased 21% year-over-year due to downtime at a non-operated gas processing plant that began in the middle of Q2 2018 and continued through the middle of Q3 2018.

Activity review

- Q3 2018 activity focused on permitting and other pre-drill activities associated with our first operated well in Germany, Burgmoor Z5 (46% working interest) in the Dümmersee-Uchte area, which we expect to drill in early 2019, in addition to performing workover opportunities and optimization reviews across our operated asset base.
- During the remainder of 2018, we plan to continue preparations for the drilling of the Burgmoor Z5 well (46% working interest).

Sales

- The price of our natural gas in Germany is based on the NCG and GPL indexes, which are both highly correlated to the TTF benchmark. Crude oil in Germany is priced with reference to Dated Brent.
- Sales per boe for the three and nine months ended September 30, 2018 increased versus all comparable periods, consistent with increases in both crude oil and natural gas benchmark prices.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Royalties as a percentage of sales of 11.6% in Q3 2018 was higher than 6.6% in Q2 2018 and lower than 14.4% in Q3 2017 due to the impact of a prior period adjustment booked in the current quarter.
- Royalties as a percentage of sales was relatively consistent for the nine months ended September 30, 2018 versus the comparable period in the prior year.

Transportation

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer and deliver crude oil to the refinery.
- Transportation expense in Q3 2018 was lower than both Q2 2018 and Q3 2017 due to the timing of transportation cost adjustments.
- Transportation expense for the nine months ended September 30, 2018 was consistent with the comparable period in the prior year.

Operating

- Operating expense on a per unit basis in Q3 2018 was lower versus Q2 2018 due to lower activity levels at non-operated properties.
- Operating expense on a per unit basis increased for the three and nine months ended September 30, 2018, versus the comparable periods in the prior year. The increase was primarily due to increased gas processing tariffs, the impact of a stronger Euro versus the Canadian dollar and the impact of fixed costs on lower volumes.

General and administration

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

Current income taxes

- As a result of our tax pools in Germany, we do not expect to incur current income taxes for 2018 in the German Business Unit.
- For 2019, we are not expecting significant cash taxes. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.

Ireland Business Unit

Overview

- Entered Ireland in 2009 with an investment in the offshore Corrib gas field.
- The Corrib gas field is located offshore northwest Ireland and comprises six offshore wells, offshore and onshore sales and transportation pipeline segments, as well as a natural gas processing facility.
- Vermilion currently holds an 18.5% non-operated interest.
- Vermilion has a strategic partnership with Canada Pension Plan Investment Board ("CPPIB") that is expected to result in Vermilion increasing ownership in Corrib to 20% and assuming operatorship. This is expected to occur before the end of 2018.

Operational and financial review

Ireland business unit ($M except as indicated)	Q3 2018	Q2 2018	Q3 2017	Q3/18 vs. Q2/18	Q3/18 vs. Q3/17	YTD 2018	YTD 2017	2018 vs. 2017
Production and sales								
Natural gas (mmcf/d)	**51.38**	56.56	49.04	(9)%	5%	**56.23**	59.16	(5)%
Total (boe/d)	**8,563**	9,426	8,173	(9)%	5%	**9,372**	9,861	(5)%
Activity								
Capital expenditures	**(50)**	87	1,101	N/A	N/A	**84**	224	(63)%
Financial results								
Sales	**50,228**	47,862	28,218	5%	78%	**151,765**	109,537	39%
Transportation	**(1,460)**	(1,268)	(1,252)	15%	17%	**(4,014)**	(3,709)	8%
Operating	**(3,354)**	(4,306)	(5,717)	(22)%	(41)%	**(10,869)**	(14,619)	(26)%
General and administration	**(3,597)**	(1,443)	(670)	149%	437%	**(6,349)**	(1,803)	252%
Fund flows from operations	**41,817**	40,845	20,579	2%	103%	**130,533**	89,406	46%
Netbacks ($/boe)								
Sales	**63.76**	55.80	37.53	14%	70%	**59.32**	40.69	46%
Transportation	**(1.85)**	(1.48)	(1.66)	25%	11%	**(1.57)**	(1.38)	14%
Operating	**(4.26)**	(5.02)	(7.60)	(15)%	(44)%	**(4.25)**	(5.43)	(22)%
General and administration	**(4.57)**	(1.68)	(0.89)	172%	413%	**(2.48)**	(0.67)	270%
Fund flows from operations netback	**53.08**	47.62	27.38	11%	94%	**51.02**	33.21	54%
Reference prices								
NBP ($/mmbtu)	**10.95**	9.42	6.78	16%	62%	**10.12**	7.10	43%
NBP (€/mmbtu)	**7.20**	6.12	4.61	18%	56%	**6.58**	4.88	35%

Production

- Q3 2018 production decreased 9% quarter-over-quarter due to the impact of planned downtime in September to perform maintenance activities and natural declines. Production increased 5% year-over-year due to unplanned downtime following a plant turnaround in Q3 2017.

Activity review

- On July 12, 2017 Vermilion and CPPIB announced a strategic partnership in Corrib, whereby CPPIB will acquire Shell E&P Ireland Limited's 45% interest in Corrib for total cash consideration of €830 million, subject to customary closing adjustments and future contingent value payments based on performance and realized pricing. At closing, Vermilion expects to assume operatorship of Corrib. In addition to operatorship, CPPIB plans to transfer a 1.5% working interest to Vermilion for €19.4 million ($28.4 million), before closing adjustments. Vermilion's incremental 1.5% ownership of Corrib would represent approximately 700 boe/d (100% gas) based on current production expectations for Corrib. The acquisition has an effective date of January 1, 2017 and is anticipated to close before the end of 2018.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Sales per boe for the three and nine months ended September 30, 2018 increased versus all comparable periods consistent with increases in the NBP reference price.

Royalties

- Our production in Ireland is not subject to royalties.

Transportation

- Transportation expense in Ireland relates to payments under a ship-or-pay agreement related to the Corrib project.
- Transportation expense for the three and nine months ended September 30, 2018 increased versus all comparable periods due to the impact of a prior period adjustment recorded in the current quarter. For the nine months ended September 30, 2018, this increase was partially offset by a decrease in tariff charges and reduced production volumes.

Operating

- Q3 2018 operating expense was lower versus Q2 2018 and Q3 2017 due to a decrease in overhead allocations during the period, partially offset by an increase in maintenance activity as a result of pipeline inspections completed during the current quarter.
- For the nine months ended September 30, 2018, operating expense was lower versus the comparable period in the prior year due to higher maintenance activities in the prior year.

General and administration

- The increase in general and administration expense versus all comparable periods is primarily due to transition costs associated with the aforementioned strategic partnership in Corrib.

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 18 well bores and five lateral sidetrack wells.
- Wells that utilize horizontal legs (ranging in length from 500 to 3,000 plus metres) are located 600 metres below the seabed in approximately 55 metres of water depth.

Operational and financial review

Australia business unit ($M except as indicated)	Q3 2018	Q2 2018	Q3 2017	Q3/18 vs. Q2/18	Q3/18 vs. Q3/17	YTD 2018	YTD 2017	2018 vs. 2017
Production								
Crude oil (bbls/d)	**4,704**	4,132	5,473	14%	(14)%	**4,601**	6,032	(24)%
Sales								
Crude oil (bbls/d)	**3,935**	4,164	5,722	(5)%	(31)%	**4,322**	6,057	(29)%
Inventory (mbbls)								
Opening crude oil inventory	**139**	142	131			**134**	115	
Crude oil production	**433**	376	503			**1,256**	1,647	
Crude oil sales	**(362)**	(379)	(526)			**(1,180)**	(1,654)	
Closing crude oil inventory	**210**	139	108			**210**	108	
Activity								
Capital expenditures	**16,061**	11,368	10,154	41%	58%	**31,878**	22,750	40%
Financial results								
Sales	**35,848**	37,364	35,257	(4)%	2%	**111,382**	118,305	(6)%
Operating	**(11,585)**	(12,809)	(12,292)	(10)%	(6)%	**(37,442)**	(37,967)	(1)%
General and administration	**(1,020)**	(982)	(1,675)	4%	(39)%	**(3,527)**	(5,001)	(29)%
Current income taxes	**(3,101)**	(5,006)	(4,538)	(38)%	(32)%	**(13,625)**	(19,028)	(28)%
Fund flows from operations	**20,142**	18,567	16,752	8%	20%	**56,788**	56,309	1%
Netbacks ($/boe)								
Sales	**99.01**	98.61	66.97	—%	48%	**94.39**	71.55	32%
Operating	**(32.00)**	(33.81)	(23.35)	(5)%	37%	**(31.73)**	(22.96)	38%
General and administration	**(2.82)**	(2.59)	(3.18)	9%	(11)%	**(2.99)**	(3.02)	(1)%
PRRT	**0.70**	(7.00)	(8.25)	N/A	N/A	**(6.14)**	(9.83)	(38)%
Corporate income taxes	**(9.27)**	(6.21)	(0.37)	49%	2,405%	**(5.41)**	(1.68)	222%
Fund flows from operations netback	**55.62**	49.00	31.82	14%	75%	**48.12**	34.06	41%
Reference prices								
Dated Brent (US $/bbl)	**75.27**	74.35	52.08	1%	45%	**72.13**	51.90	39%
Dated Brent ($/bbl)	**98.37**	95.99	65.22	2%	51%	**92.87**	67.82	37%

Production

- Q3 2018 production increased 14% quarter-over-quarter due to the reinstatement of production from well workover activity that was successfully completed in Q2 2018. Production decreased 14% year-over-year due to natural declines.
- Production volumes are managed within corporate targets while meeting customer demands and the requirements of long-term supply agreements.
- We continue to plan for long-term annual production levels of approximately 6,000 bbls/d.

Activity review

- We continued to prepare for our Q4 2018 two (2.0 net) well drilling campaign during the quarter. This entailed securing all necessary third party agreements and regulatory permits to drill, along with a significant portion of the materials.
- During the remainder of 2018, activity will be focused on our planned two (2.0 net) well drilling campaign.

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Q3 2018 sales per boe were consistent with Q2 2018, but lower sales volumes resulted in a slight decrease in sales quarter-over-quarter.
- Sales per boe for the three and nine months ended September 30, 2018 increased versus the comparable periods in the prior year, consistent with increases in the Dated Brent reference price.

Royalties and transportation

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

Operating

- Q3 2018 operating expense decreased versus Q2 2018 due to lower chemical usage and lower maintenance activity in the current quarter related to a planned shutdown to clean out vessels.
- For the three and nine months ended September 30, 2018, per unit operating expense increased versus the comparable periods in the prior year due to the impact of fixed costs on lower volumes, as well as higher diesel usage and helicopter costs.

General and administration

- Fluctuations in general and administration expense for all comparable periods are primarily due to the timing of expenditures and allocations from our corporate segment. In addition, the decrease in general and administration expense for the three and nine months ended September 30, 2018 versus the comparable periods in 2017 is primarily due to the impact of IFRS 16 adoption in the current year. As a result of this new accounting pronouncement, certain payments associated with office space in Australia have been accounted for as leases. Please refer to "Recently Adopted Accounting Pronouncements" for additional information.

Current income taxes

- In Australia, current income taxes include both PRRT and corporate income taxes. PRRT is a profit based tax applied at a rate of 40% on sales less eligible expenditures, including operating expenses and capital expenditures. Corporate income taxes are applied at a rate of 30% on taxable income after eligible deductions, which include PRRT paid.
- Full year effective tax rates are estimated each quarter based on forecasted commodity prices and operational results. The estimated full year effective tax rate is applied on a pro-rata basis to quarterly results. As such, fluctuations between the reporting periods occur due to changes in estimated tax rates.
- For 2018, the effective rate on current taxes, inclusive of corporate allocations, is expected to be between 14% to 18% of pre-tax fund flows from operations. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.

United States Business Unit

Overview

- Entered the United States in September 2014.
- Interests include approximately 149,700 net acres of land (72% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Tight oil development targeting the Turner Sands at depths of approximately 1,500 metres (East Finn) and 2,600 metres (Hilight).

Operational and financial review

United States business unit ($M except as indicated)	Q3 2018	Q2 2018	Q3 2017	Q3/18 vs. Q2/18	Q3/18 vs. Q3/17	YTD 2018	YTD 2017	2018 vs. 2017
Production and sales								
Crude oil (bbls/d)	**1,461**	655	880	123%	66%	**900**	666	35%
NGLs (bbls/d)	**714**	62	56	1,052%	1,175%	**268**	52	415%
Natural gas (mmcf/d)	**4.82**	0.40	0.64	1,105%	653%	**1.81**	0.43	321%
Total (boe/d)	**2,979**	784	1,043	280%	186%	**1,469**	789	86%
Production mix (% of total)								
Crude oil	**49%**	84%	84%			**61%**	84%	
NGLs	**24%**	8%	5%			**18%**	7%	
Natural gas	**27%**	8%	11%			**21%**	9%	
Activity								
Capital expenditures	**11,386**	10,702	1,362	6%	736%	**37,956**	18,056	110%
Acquisitions	**187,987**	11	1,250			**188,066**	3,312	
Gross wells drilled	**—**	—	—			**5.00**	3.00	
Net wells drilled	**—**	—	—			**5.00**	3.00	
Financial results								
Sales	**14,551**	5,230	4,771	178%	205%	**23,840**	11,005	117%
Royalties	**(3,444)**	(1,451)	(1,321)	137%	161%	**(6,017)**	(3,080)	95%
Transportation	**—**	—	(26)	—%	(100)%	**—**	(26)	(100)%
Operating	**(2,633)**	(374)	(629)	604%	319%	**(3,573)**	(1,301)	175%
General and administration	**(2,397)**	(1,337)	(935)	79%	156%	**(4,910)**	(3,067)	60%
Fund flows from operations	**6,077**	2,068	1,860	194%	227%	**9,340**	3,531	165%
Netbacks ($/boe)								
Sales	**53.10**	73.30	49.72	(28)%	7%	**59.45**	51.07	16%
Royalties	**(12.57)**	(20.35)	(13.77)	(38)%	(9)%	**(15.00)**	(14.29)	5%
Transportation	**—**	—	(0.27)	—%	(100)%	**—**	(0.12)	(100)%
Operating	**(9.61)**	(5.24)	(6.56)	83%	46%	**(8.91)**	(6.04)	48%
General and administration	**(8.75)**	(18.74)	(9.74)	(53)%	(10)%	**(12.24)**	(14.23)	(14)%
Fund flows from operations netback	**22.17**	28.97	19.38	(23)%	14%	**23.30**	16.39	42%
Realized prices								
Crude oil ($/bbl)	**87.34**	83.85	55.74	4%	57%	**84.23**	57.68	46%
NGLs ($/bbl)	**29.22**	30.93	26.35	(6)%	11%	**29.53**	20.58	43%
Natural gas ($/mmbtu)	**2.01**	1.59	2.07	26%	(3)%	**2.01**	1.95	3%
Total ($/boe)	**53.10**	73.30	49.72	(28)%	7%	**59.45**	51.07	16%
Reference prices								
WTI (US $/bbl)	**69.50**	67.88	48.20	2%	44%	**66.75**	49.47	35%
WTI ($/bbl)	**90.83**	87.63	60.37	4%	50%	**85.95**	64.64	33%
Henry Hub (US $/mmbtu)	**2.90**	2.80	3.00	4%	(3)%	**2.90**	3.17	(9)%
Henry Hub ($/mmbtu)	**3.80**	3.61	3.76	5%	1%	**3.74**	4.14	(10)%

Production

- Q3 2018 production increased 280% from the prior quarter and 186% year-over-year due to the production associated with an acquisition we completed in August 2018, and the completion of our 2018 East Finn drilling campaign as we brought the final two (2.0 net) wells on production in the quarter.

Activity

- In August 2018, we acquired all the assets of a private oil company in the Powder River Basin for total cash consideration of approximately $186 million. The assets are located in Campbell County, Wyoming, approximately 40 miles (65 kilometres) northwest of Vermilion's existing operations. The assets include approximately 55,700 net acres of land (approximately 96% working interest) and approximately 2,500 boe/d (63% oil and NGLs) of production with an estimated annual base decline rate of 13%.
- We also completed and brought on production the final two (2.0 net) wells of our five (5.0 net) well 2018 East Finn drilling program.

Sales

- The price of crude oil in the United States is directly linked to WTI, subject to local market differentials within the United States.
- Q3 2018 sales per boe decreased versus Q2 2018 due to increased relative gas production from the recently acquired assets.
- For the three and nine months ended September 30, 2018, sales per boe increased versus the comparable periods in 2017. This was due to the significant increase in the WTI reference price in both of these periods.

Royalties

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax.
- Royalties as a percentage of sales were lower versus all comparable periods due to the impact of a prior period adjustment recorded in the current period and lower royalty rate associated with the recently acquired assets.

Operating

- Fluctuations in operating expense versus all comparable periods were due to the timing of maintenance activity and incremental costs from the recently acquired assets.

General and administration

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

Current income taxes

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

Corporate

Overview

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

Operational and financial review

Corporate ($M)	Q3 2018	Q2 2018	Q3 2017	YTD 2018	YTD 2017
Production and sales					
Natural gas (mmcf/d)	**1.17**	—	—	**0.39**	—
Total (boe/d)	**195**	—	—	**66**	—
Activity					
Capital expenditures	**1,619**	3,080	4,653	**8,065**	6,433
Acquisitions	**207**	—	—	**207**	40
Gross wells drilled	**—**	—	—	**1.00**	—
Net wells drilled	**—**	—	—	**1.00**	—
Financial results					
Sales	**1,083**	—	—	**1,083**	—
Royalties	**(279)**	—	—	**(279)**	—
Operating	**(201)**	—	—	**(201)**	—
General and administration recovery (expense)	**854**	(3,393)	(1,834)	**(3,713)**	(4,818)
Current income taxes	**(862)**	(111)	480	**(1,159)**	15
Interest expense	**(19,772)**	(16,572)	(13,400)	**(51,932)**	(43,603)
Realized (loss) gain on derivatives	**(37,365)**	(27,859)	8,723	**(82,939)**	12,214
Realized foreign exchange loss	**(3,100)**	(4,105)	(4,110)	**(5,651)**	(583)
Realized other income	**177**	230	214	**608**	508
Fund flows from operations	**(59,465)**	(51,810)	(9,927)	**(144,183)**	(36,267)

Production review

- Production in our Central and Eastern Europe business unit averaged 195 boe/d in Q3 2018, marking the first gas production for the business unit from our South Battonya concession in Hungary. The well was brought on production in mid-August and is producing in-line with our expectations at 5.3 mmcf/d (880 boe/d).

Activity review

- In Q3 2018, we brought on production our first exploratory well (100% working interest) in the South Battonya concession, which we drilled and tested in the first quarter of this year. We have identified a new Pannonian gas prospect in our Ebes license in Hungary following further interpretation of 3D seismic data in the quarter.
- During the remainder of 2018, activity will be focused on preparation for our 2019 drilling campaigns in Hungary, Slovakia and Croatia. A new 2D seismic acquisition campaign in Croatia is also expected to be carried out in Q4 2018.

General and administration

- Fluctuations in general and administration expense for the three and nine months ended September 30, 2018 versus all comparable periods were due to allocations to the various business unit segments.
- On a consolidated basis, general and administration expense decreased 19% quarter-over-quarter to $13.2 million in Q3 2018 (compared to $16.2 million in Q2 2018), primarily due to the absence of transaction costs incurred on our Spartan acquisition in the prior quarter. Acquisition-related costs of $1.3 million were incurred in the nine months ended September 30, 2018.

Current income taxes

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

Interest expense

- The increase in interest expense in Q3 2018 versus Q2 2018 was due to higher drawings on the revolving credit facility.
- For the three and nine months ended September 30, 2018, interest expense increased versus the comparative periods in the prior year due to the impact of higher drawings on the revolving credit facility, as well as the impact of IFRS 16 adoption in the current year. Please refer to "Recently Adopted Accounting Pronouncements" for additional information regarding the adoption of IFRS 16.

Realized gain or loss on derivatives

- The realized loss on derivatives for the three and nine months ended September 30, 2018 is related primarily to amounts paid on crude oil and European natural gas hedges.
- A listing of derivative positions as at September 30, 2018 is included in “Supplemental Table 2” of this MD&A.

Financial Performance Review

($M except per share)	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016
Petroleum and natural gas sales	**508,411**	394,498	318,269	317,341	248,505	271,391	261,601	259,891
Net (loss) earnings	**(15,099)**	(61,364)	24,740	8,645	(39,191)	48,264	44,540	(4,032)
Net earnings (loss) per share								
Basic	**(0.10)**	(0.46)	0.20	0.07	(0.32)	0.40	0.38	(0.03)
Diluted	**(0.10)**	(0.46)	0.20	0.07	(0.32)	0.39	0.37	(0.03)

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

	Q3 2018		Q2 2018		Q3 2017		YTD 2018		YTD 2017	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	**508,411**	**57.90**	394,498	53.72	248,505	39.66	**1,221,178**	**54.64**	781,497	43.27
Royalties	**(53,786)**	**(6.13)**	(31,512)	(4.29)	(16,994)	(2.71)	**(108,293)**	**(4.85)**	(50,935)	(2.82)
Petroleum and natural gas revenues	**454,625**	**51.77**	362,986	49.43	231,511	36.95	**1,112,885**	**49.79**	730,562	40.45
Transportation	**(13,721)**	**(1.56)**	(11,046)	(1.50)	(10,800)	(1.72)	**(34,949)**	**(1.56)**	(31,462)	(1.74)
Operating	**(97,758)**	**(11.13)**	(78,947)	(10.75)	(61,832)	(9.87)	**(244,544)**	**(10.94)**	(177,027)	(9.80)
General and administration	**(13,234)**	**(1.51)**	(14,153)	(1.93)	(12,114)	(1.93)	**(39,115)**	**(1.75)**	(38,432)	(2.13)
PRRT	**254**	**0.03**	(2,652)	(0.36)	(4,345)	(0.69)	**(7,246)**	**(0.32)**	(16,247)	(0.90)
Corporate income taxes	**(9,401)**	**(1.07)**	(12,692)	(1.73)	(3,092)	(0.49)	**(30,807)**	**(1.38)**	(14,618)	(0.81)
Interest expense	**(19,772)**	**(2.25)**	(16,572)	(2.26)	(13,400)	(2.14)	**(51,932)**	**(2.32)**	(43,603)	(2.41)
Realized (loss) gain on derivative instruments	**(37,365)**	**(4.26)**	(27,859)	(3.79)	8,723	1.39	**(82,939)**	**(3.71)**	12,214	0.68
Realized foreign exchange loss	**(3,100)**	**(0.35)**	(4,105)	(0.56)	(4,110)	(0.66)	**(5,651)**	**(0.25)**	(583)	(0.03)
Realized other income	**177**	**0.02**	230	0.03	214	0.03	**608**	**0.03**	508	0.03
Fund flows from operations	**260,705**	**29.69**	195,190	26.58	130,755	20.87	**616,310**	**27.59**	421,312	23.34

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

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

	Q3 2018	Q2 2018	Q3 2017	YTD 2018	YTD 2017
Fund flows from operations	**260,705**	195,190	130,755	**616,310**	421,312
Equity based compensation	**(13,056)**	(10,961)	(12,858)	**(43,767)**	(45,492)
Unrealized (loss) gain on derivative instruments	**(75,829)**	(105,284)	(24,198)	**(163,770)**	78,950
Unrealized foreign exchange (loss) gain	**(23,044)**	(12,458)	(3,016)	**(26,877)**	31,082
Unrealized other expense	**(203)**	(199)	(200)	**(597)**	(440)
Accretion	**(8,041)**	(7,819)	(6,850)	**(23,014)**	(19,980)
Depletion and depreciation	**(166,343)**	(143,385)	(120,826)	**(434,621)**	(362,504)
Deferred tax	**10,712**	23,552	(1,998)	**24,613**	(49,315)
Net (loss) earnings	**(15,099)**	(61,364)	(39,191)	**(51,723)**	53,613

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 the Vermilion Incentive Plan ("VIP").

Equity based compensation expense increased in Q3 2018 compared to Q2 2018 and Q3 2017 due to a higher number of outstanding units in the current quarter.

Unrealized gain or loss on derivative instruments

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

For the three and nine months ended September 30, 2018, we recognized unrealized losses on derivative instruments of $75.8 million and $163.8 million, respectively. The unrealized loss primarily related to European natural gas and crude oil derivative instruments for 2018 through 2020.

Unrealized foreign exchange gain or loss

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

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

For the three months ended September 30, 2018, the impact of the Canadian dollar strengthening against the Euro was more significant than the impact of the Canadian dollar weakening against the US dollar, resulting in an unrealized loss on foreign exchange of $23.0 million. For the nine months ended September 30, 2018, the unrealized loss on foreign exchange of $26.9 million was primarily driven by the impact of the Canadian dollar weakening against the US dollar.

As at September 30, 2018, a $0.01 appreciation of the Euro against the Canadian dollar would result in a $3.4 million increase to net earnings as a result of an unrealized gain on foreign exchange. In contrast, a $0.01 appreciation of the US dollar against the Canadian dollar would result in a $3.3 million decrease to net earnings as a result of an unrealized loss on foreign exchange.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. The increase in accretion expense was primarily attributable to new obligations recognized following acquisitions in 2018.

Depletion and depreciation

Depletion and depreciation expense is recognized to allocate the cost of capital assets over the useful life of the respective assets. Depletion and depreciation expense per unit of production is determined for each depletion unit (which are groups of assets within a specific production area that have similar economic lives) by dividing the sum of the net book value of capital assets and future development costs by total proved plus probable reserves.

Fluctuations in depletion and depreciation expense are primarily the result of changes in produced crude oil and natural gas volumes and changes in depletion and depreciation per unit. Fluctuations in depletion and depreciation per unit are the result of changes in reserves, future development costs, and relative production mix.

Depletion and depreciation on a per boe basis for Q3 2018 of $18.95 was consistent with $19.52 in Q2 2018. For the three and nine months ended September 30, 2018, depletion and depreciation on a per boe basis of $18.95 and $19.45, respectively, were lower than $19.28 and $20.07 for the respective comparable periods in the prior year due to reduced depletion and depreciation rates as a result of increased reserves and lower estimated future development costs.

Deferred tax

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

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

For the three and nine months ended September 30, 2018, deferred tax recoveries of $10.7 million and $24.6 million resulted from unrealized losses on derivative instruments.

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 forecasted fund flows from operations is sufficient to finance planned capital expenditures, dividends, and abandonment and reclamation expenditures. To the extent that forecasted fund flows from operations is not expected to be sufficient to fulfill such expenditures, we will evaluate our ability to finance any shortfall with debt (including borrowing using the unutilized capacity of our existing revolving credit facility), issue equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

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

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

Net debt

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

	As at	
($M)	Sep 30, 2018	Dec 31, 2017
Long-term debt	**1,728,889**	1,270,330
Current liabilities	**629,893**	363,306
Current assets	**(324,696)**	(261,846)
Net debt	**2,034,086**	1,371,790
Ratio of net debt to quarterly annualized fund flows from operations	**1.95**	1.89

As at September 30, 2018, net debt increased to $2.03 billion (December 31, 2017 - $1.37 billion) due to the impact of the acquisitions closed in the first nine months of 2018 and a $100.1 million increase in net current derivative liability. This increase in net debt was partially offset by an increase in fund flows from operations and resulted in a slight increase in the ratio of net debt to quarterly annualized fund flows from operations from 1.89 for 2017 to 1.95 for the current period.

Long-term debt

The balances recognized on our balance sheet are as follows:

	As at	
($M)	Sep 30, 2018	Dec 31, 2017
Revolving credit facility	**1,345,730**	899,595
Senior unsecured notes	**383,159**	370,735
Long-term debt	**1,728,889**	1,270,330

Revolving Credit Facility

In Q2 2018, we negotiated an increase in our revolving credit facility from $1.4 billion to $1.6 billion and an extension of the maturity from May 31, 2021 to May 31, 2022. In Q3 2018, we negotiated a further increase in our revolving credit from $1.6 billion to $1.8 billion.

As at September 30, 2018, Vermilion had in place a bank revolving credit facility maturing May 31, 2022 with the below terms, outstanding positions, and covenants.

	As at	
($M)	Sep 30, 2018	Dec 31, 2017
Total facility amount	**1,800,000**	1,400,000
Amount drawn	**(1,345,730)**	(899,595)
Letters of credit outstanding	**(8,800)**	(7,400)
Unutilized capacity	**445,470**	493,005

As at September 30, 2018, the revolving credit facility was subject to the following covenants:

		As at	
Financial covenant	Limit	Sep 30, 2018	Dec 31, 2017
Consolidated total debt to consolidated EBITDA	4.0	**1.67**	1.87
Consolidated total senior debt to consolidated EBITDA	3.5	**1.30**	1.30
Consolidated total senior debt to total capitalization	55%	**32%**	32%

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

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

Senior Unsecured Notes

On March 13, 2017, Vermilion issued US$300 million of senior unsecured notes at par. The notes bear interest at a rate of 5.625% per annum, paid semi-annually on March 15 and September 15, and mature on March 15, 2025. As direct senior unsecured obligations of Vermilion, the notes rank equally in right of payment with existing and future senior indebtedness of the Company.

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

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

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

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

Shareholders' capital

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

In total, dividends declared in 2018 were $282.8 million.

The following table outlines our dividend payment history:

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

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

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

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount ($M)
Balance at December 31, 2017	**122,119**	**2,650,706**
Shares issued for corporate acquisition	**27,883**	**1,234,676**
Shares issued for the Dividend Reinvestment Plan	**1,030**	**43,936**
Vesting of equity based awards	**1,025**	**54,057**
Equity based compensation	**256**	**10,626**
Share-settled dividends on vested equity based awards	**184**	**7,773**
Balance as at September 30, 2018	**152,497**	**4,001,774**

As at September 30, 2018, there were approximately 1.9 million VIP awards outstanding. As at October 24, 2018, there were approximately 152.5 million common shares issued and outstanding.

Asset Retirement Obligations

As at September 30, 2018, asset retirement obligations were $598.1 million compared to $517.2 million as at December 31, 2017.

The increase in asset retirement obligations is largely attributable to additional obligations recognized as a result of acquisitions completed in 2018.

Off Balance Sheet Arrangements

We have not entered into any guarantee or off balance sheet arrangements that would materially impact our financial position or results of operations.

Risk Management

Vermilion is exposed to various market and operational risks. For a discussion of these risks, please see Vermilion's MD&A and Annual Information Form, each for the year ended December 31, 2017 available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

Critical Accounting Estimates

The preparation of financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of any possible contingencies. These estimates and assumptions are developed based on the best available information which management believed to be reasonable at the time such estimates and assumptions were made. As such, these assumptions are uncertain at the time estimates are made and could change, resulting in a material impact on Vermilion's consolidated financial statements. Estimates are reviewed by management on an ongoing basis and as a result may change from period to period due to the availability of new information or changes in circumstances. Additionally, as a result of the unique circumstances of each jurisdiction that Vermilion operates in, the critical accounting estimates may affect one or more jurisdictions. With the exception of additional judgments, estimates, and assumptions related to the application of IFRS 16 (see notes to the Condensed Consolidated Financial Statements), there have been no material changes to our critical accounting estimates used in applying accounting policies for the three and nine months ended September 30, 2018. Further information, including a discussion of critical accounting estimates, can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2017, available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

Internal Control Over Financial Reporting

There was no change in Vermilion's internal control over financial reporting ("ICFR") during the period covered by this MD&A that materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Vermilion has limited the scope of design controls and procedures ("DC&P") and internal controls over financial reporting to exclude controls, policies and procedures of Spartan Energy Corp, which was acquired on May 28, 2018. The scope limitation is in accordance with section 3.3(1)(b) of NI 52-109 which allows an issuer to limit the design of DC&P and ICFR to exclude controls, policies, and procedures of a business that the issuer acquired not more than 365 days before the end of the fiscal period.

The table below presents the summary financial information of Spartan included in Vermilion's financial statements as at and for the nine months ended September 30, 2018:

($MM)	As at September 30, 2018
Non-current assets	1,540
Non-current liabilities	111
Net assets	1,394

($MM)	Nine months ended September 30, 2018
Revenue	157
Net earnings	40

Recently Adopted Accounting Pronouncements

IFRS 9 "Financial instruments"

On January 1, 2018, Vermilion adopted IFRS 9 *"Financial Instruments"* as issued by the IASB. IFRS 9 includes a new classification and measurement approach for financial assets and a forward-looking 'expected credit loss' model. The adoption of IFRS 9 did not have a material impact on Vermilion's consolidated financial statements.

IFRS 15 "Revenue from contracts with customers"

On January 1, 2018, Vermilion adopted IFRS 15 "Revenue from Contracts with Customers" IFRS 15 establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. Vermilion's revenue relates to the sale of petroleum and natural gas to customers at specified delivery points at benchmark prices.

Vermilion adopted IFRS 15 using the modified retrospective approach. Under this transitional provision, the cumulative effect of initially applying IFRS 15 is recognized on the date of initial application as an adjustment to retained earnings. No adjustment to retained earnings was required upon adoption of IFRS 15.

IFRS 16 "Leases"

In Q3 2018, Vermilion began applying IFRS 16 "Leases" effective January 1, 2018. The stated objective of IFRS 16 is to provide information that faithfully represents lease transactions and provides a basis for users of financial statements to assess the amount, timing and uncertainty of cash flows arising from leases. IFRS 16 accomplishes this by introducing a single lessee accounting model that requires lessees to recognize a lease obligation and right-of-use asset for the majority of leases. As the Company completed the assessment of the standard and applicable contracts during Q3 2018, Vermilion elected for earlier application of IFRS 16 to achieve the stated objectives of the standard and to increase comparability of results in future periods. Vermilion began applying the standard beginning effective January 1, 2018.

Effective January 1, 2018, Vermilion applied IFRS 16 retrospectively with the cumulative effect of initially applying the standard recognized as a $97.1 million increase to right-of-use assets (included in "Capital assets") and lease obligations ($86.1 million recorded in "Lease obligations" and $11.0 million recorded in "Accounts payable and accrued liabilities"). The right-of-use assets and lease obligations recognized largely relate to the Company's head office lease in Calgary and long-term leases for oil storage facilities in France.

Q1 and Q2 2018 results, which were previously released as prepared under IAS 17, have been revised to reflect the impact of this new accounting pronouncement.

The impact of applying IFRS 16 to Q1 and Q2 2018 on the statement of net earnings is summarized in the table below:

($M)	Notes	Q1 2018 as previously reported	Impact of IFRS 16	Q1 2018 revised	Q2 2018 as previously reported	Impact of IFRS 16	Q2 2018 revised
Operating	A	68,375	(536)	**67,839**	79,493	(546)	**78,947**
Transportation	B	11,019	(837)	**10,182**	11,851	(805)	**11,046**
Interest expense		14,334	1,254	**15,588**	15,333	1,239	**16,572**
General and administration	C	14,544	(2,816)	**11,728**	16,241	(2,088)	**14,153**
Depletion and depreciation		121,559	3,334	**124,893**	140,045	3,340	**143,385**
Net earnings		25,139	(399)	**24,740**	(60,224)	(1,140)	**(61,364)**

A. The application of IFRS 16 reduced operating expenses in the following business units: Canada (Q1 2018 - $0.3MM; Q2 2018 - $0.3MM), France (Q1 2018 - $0.1MM; Q2 2018 - $0.1MM), Netherlands (Q1 2018 - $0.1MM; Q2 2018 - $0.1MM), and Australia (Q1 2018 - $0.1MM; Q2 2018 - $0.1MM).
B. The application of IFRS 16 reduced transportation expense in the France business unit.
C. The application of IFRS 16 primarily reduced general and administration expenses in the following business units: Canada (Q1 2018 - $1.2MM; Q2 2018 - $0.8MM), Netherlands (Q1 2018 - $0.2MM; Q2 2018 - $0.2MM), United States (Q1 2018 - $0.1MM; Q2 2018 - $0.1MM), and Corporate ($Q1 2018 - $1.3MM; Q2 2018 - $0.9MM).

The impact of applying IFRS 16 to Q1 and Q2 2018 on the statement of cash flows is summarized in the table below:

($M)	Q1 2018 as previously reported	Impact of IFRS 16	Q1 2018 revised	Q2 2018 as previously reported	Impact of IFRS 16	Q2 2018 revised
Drilling and development	124,811	(153)	**124,658**	76,854	(145)	**76,709**
Payments on lease obligations	1,264	3,086	**4,350**	1,541	2,347	**3,888**

Please refer to Supplemental Table 5 for Q1 and Q2 2018 netbacks after adjusting for the impact of IFRS 16.

Supplemental Table 1: Netbacks

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

	Q3 2018			YTD 2018			Q3 2017	YTD 2017
	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	70.65	1.44	**46.02**	66.64	1.47	**39.89**	26.65	30.53
Royalties	(10.52)	(0.02)	**(6.40)**	(9.37)	0.06	**(4.86)**	(2.30)	(3.09)
Transportation	(1.04)	(0.46)	**(1.72)**	(1.30)	(0.31)	**(1.55)**	(1.55)	(1.62)
Operating	(11.76)	(1.44)	**(10.52)**	(10.95)	(1.30)	**(9.50)**	(7.62)	(7.50)
Operating netback	47.33	(0.48)	**27.38**	45.02	(0.08)	**23.98**	15.18	18.32
General and administration			**(0.25)**			**(0.32)**	(0.77)	(0.91)
Fund flows from operations netback			**27.13**			**23.66**	14.41	17.41
France								
Sales	95.46	—	**95.46**	91.27	—	**91.27**	63.24	64.22
Royalties	(12.08)	—	**(12.08)**	(11.56)	—	**(11.56)**	(6.12)	(6.09)
Transportation	(1.91)	—	**(1.91)**	(2.39)	—	**(2.39)**	(3.29)	(3.44)
Operating	(13.00)	—	**(13.00)**	(13.51)	—	**(13.51)**	(12.58)	(12.44)
Operating netback	68.47	—	**68.47**	63.81	—	**63.81**	41.25	42.25
General and administration			**(3.19)**			**(3.45)**	(2.43)	(3.16)
Current income taxes			**(6.54)**			**(4.72)**	(1.34)	(2.78)
Fund flows from operations netback			**58.74**			**55.64**	37.48	36.31
Netherlands								
Sales	82.32	10.08	**60.74**	77.08	9.22	**55.54**	39.23	41.04
Royalties	—	(0.26)	**(1.52)**	—	(0.22)	**(1.30)**	(0.66)	(0.66)
Operating	—	(1.42)	**(8.45)**	—	(1.65)	**(9.79)**	(8.30)	(8.70)
Operating netback	82.32	8.40	**50.77**	77.08	7.35	**44.45**	30.27	31.68
General and administration			**(0.47)**			**(0.61)**	(0.94)	(1.02)
Current income taxes			**2.51**			**(4.46)**	(3.66)	(2.23)
Fund flows from operations netback			**52.81**			**39.38**	25.67	28.43
Germany								
Sales	92.45	9.61	**67.15**	86.71	8.32	**61.02**	38.52	42.50
Royalties	(2.14)	(1.66)	**(7.81)**	(2.32)	(1.14)	**(5.48)**	(5.56)	(4.15)
Transportation	(8.83)	(0.32)	**(3.80)**	(9.64)	(0.50)	**(5.01)**	(3.94)	(4.30)
Operating	(21.41)	(2.22)	**(15.51)**	(21.95)	(2.37)	**(16.56)**	(8.55)	(12.08)
Operating netback	60.07	5.41	**40.03**	52.80	4.31	**33.97**	20.47	21.97
General and administration			**(6.61)**			**(5.13)**	(4.20)	(4.85)
Fund flows from operations netback			**33.42**			**28.84**	16.27	17.12
Ireland								
Sales	—	10.63	**63.76**	—	9.89	**59.32**	37.53	40.69
Transportation	—	(0.31)	**(1.85)**	—	(0.26)	**(1.57)**	(1.66)	(1.38)
Operating	—	(0.71)	**(4.26)**	—	(0.71)	**(4.25)**	(7.60)	(5.43)
Operating netback	—	9.61	**57.65**	—	8.92	**53.50**	28.27	33.88
General and administration			**(4.57)**			**(2.48)**	(0.89)	(0.67)
Fund flows from operations netback			**53.08**			**51.02**	27.38	33.21

	Q3 2018 Liquids $/bbl	Q3 2018 Natural Gas $/mcf	Q3 2018 Total $/boe	YTD 2018 Liquids $/bbl	YTD 2018 Natural Gas $/mcf	YTD 2018 Total $/boe	Q3 2017 Total $/boe	YTD 2017 Total $/boe
Australia								
Sales	99.01	—	**99.01**	94.39	—	**94.39**	66.97	71.55
Operating	(32.00)	—	**(32.00)**	(31.73)	—	**(31.73)**	(23.35)	(22.96)
PRRT (1)	0.70	—	**0.70**	(6.14)	—	**(6.14)**	(8.25)	(9.83)
Operating netback	67.71	—	**67.71**	56.52	—	**56.52**	35.37	38.76
General and administration			**(2.82)**			**(2.99)**	(3.18)	(3.02)
Corporate income taxes			**(9.27)**			**(5.41)**	(0.37)	(1.68)
Fund flows from operations netback			**55.62**			**48.12**	31.82	34.06
United States								
Sales	68.27	2.01	**53.10**	71.68	2.01	**59.45**	49.72	51.07
Royalties	(16.03)	(0.53)	**(12.57)**	(18.03)	(0.55)	**(15.00)**	(13.77)	(14.29)
Transportation	—	—	**—**	—	—	**—**	(0.27)	(0.12)
Operating	(9.95)	(1.45)	**(9.61)**	(9.19)	(1.30)	**(8.91)**	(6.56)	(6.04)
Operating netback	42.29	0.03	**30.92**	44.46	0.16	**35.54**	29.12	30.62
General and administration			**(8.75)**			**(12.24)**	(9.74)	(14.23)
Fund flows from operations netback			**22.17**			**23.30**	19.38	16.39
Total Company								
Sales	78.40	5.35	**57.90**	76.74	5.30	**54.64**	39.66	43.27
Realized hedging (loss) gain	(4.17)	(0.73)	**(4.26)**	(4.56)	(0.47)	**(3.71)**	1.39	0.68
Royalties	(10.14)	(0.18)	**(6.13)**	(9.02)	(0.09)	**(4.85)**	(2.71)	(2.82)
Transportation	(1.24)	(0.33)	**(1.56)**	(1.63)	(0.25)	**(1.56)**	(1.72)	(1.74)
Operating	(13.60)	(1.34)	**(11.13)**	(14.01)	(1.30)	**(10.94)**	(9.87)	(9.80)
PRRT (1)	0.05	—	**0.03**	(0.64)	—	**(0.32)**	(0.69)	(0.90)
Operating netback	49.30	2.77	**34.85**	46.88	3.19	**33.26**	26.06	28.69
General and administration			**(1.51)**			**(1.75)**	(1.93)	(2.13)
Interest expense			**(2.25)**			**(2.32)**	(2.14)	(2.41)
Realized foreign exchange loss			**(0.35)**			**(0.25)**	(0.66)	(0.03)
Other income			**0.02**			**0.03**	0.03	0.03
Corporate income taxes			**(1.07)**			**(1.38)**	(0.49)	(0.81)
Fund flows from operations netback			**29.69**			**27.59**	20.87	23.34

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

Supplemental Table 2: Hedges

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

The following tables outline Vermilion's outstanding risk management positions as at September 30, 2018:

Crude Oil	Period	Exercise date (1)	Currency	Bought Put Volume (bbl/d)	Weighted Average Bought Put Price / bbl	Sold Call Volume (bbl/d)	Weighted Average Sold Call Price / bbl	Sold Put Volume (bbl/d)	Weighted Average Sold Put Price / bbl	Swap Volume (bbl/d)	Weighted Average Swap Price / bbl	Additional Swap Volume (bbl/d) (2)
Dated Brent												
3-Way Collar	Sep 2018 - Jun 2019		CAD	2,500	91.20	2,500	98.63	2,500	76.00	—	—	—
Swap	Jan 2018 - Dec 2018		CAD	—	—	—	—	—	—	500	76.25	—
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	—	1,350	91.76	—
3-Way Collar	Jul 2017 - Dec 2018		USD	2,000	48.89	2,000	55.00	2,000	42.50	—	—	—
3-Way Collar	Oct 2017 - Dec 2018		USD	2,000	50.50	2,000	55.75	2,000	43.00	—	—	—
3-Way Collar	Aug 2018 - Jun 2019		USD	500	66.92	500	80.00	500	55.00	—	—	—
3-Way Collar	Jan 2019 - Dec 2019		USD	500	70.00	500	80.00	500	60.00	—	—	—
Collar	Jan 2018 - Dec 2018		USD	1,000	50.00	1,000	57.50	—	—	—	—	—
Swap	Jan 2018 - Dec 2018		USD	—	—	—	—	—	—	1,000	55.00	—
Swap	Apr 2018 - Mar 2019		USD	—	—	—	—	—	—	750	61.33	—
Swap	Jul 2018 - Jun 2019		USD	—	—	—	—	—	—	1,500	68.52	—
Swap	Jan 2019 - Dec 2019		USD	—	—	—	—	—	—	2,250	73.17	—
Swaption	Jan 2019 - Dec 2019	Oct 31, 2018	USD	—	—	—	—	—	—	500	79.10	—
WTI												
Swap	Jul 2018 - Dec 2018		CAD	—	—	—	—	—	—	500	83.45	—
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	—	1,050	81.41	—
Collar	Jan 2018 - Dec 2018		USD	500	50.00	500	55.00	—	—	—	—	—
Swap	Jan 2018 - Dec 2018		USD	—	—	—	—	—	—	1,000	54.00	—
Swap	Apr 2018 - Mar 2019		USD	—	—	—	—	—	—	250	54.00	—
Swaption	Jan 2019 - Dec 2019	Oct 31, 2018	USD	—	—	—	—	—	—	750	69.50	—

North American Gas	Period	Exercise date (1)	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Sold Put Volume (mmbtu/d)	Weighted Average Sold Put Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap Price / mmbtu	Additional Swap Volume (mmbtu/d) (2)
AECO												
Swap	Jan 2018 - Dec 2018		CAD	—	—	—	—	—	—	9,478	2.80	—
AECO Basis (AECO less NYMEX HH)												
Swap	Oct 2017 - Dec 2018		USD	—	—	—	—	—	—	10,000	(1.03)	—
Swap	Jan 2018 - Dec 2018		USD	—	—	—	—	—	—	20,000	(0.95)	—
Swap	Jan 2019 - Jun 2020		USD	—	—	—	—	—	—	2,500	(0.93)	—
AECO Basis (AECO less Chicago NGI)												
Swap	Nov 2018 - Mar 2019		USD	—	—	—	—	—	—	5,000	(1.46)	—
NYMEX HH												
3-Way Collar	Oct 2017 - Dec 2018		USD	10,000	3.11	10,000	3.40	10,000	2.40	—	—	—
3-Way Collar	Jan 2018 - Dec 2018		USD	10,000	3.06	10,000	3.40	10,000	2.40	—	—	—
Swap	Apr 2018 - Dec 2018		USD	—	—	—	—	—	—	10,000	3.10	—

(1) The sold swaption instrument allows the counterparty, at the specified date, to enter into a derivative instrument contract with Vermilion at the above detailed
(2) On the last business day of each month, the counterparty has the option to increase the contracted volumes for the following month.

European Gas	Period	Exercise date [1]	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Sold Put Volume (mmbtu/d)	Weighted Average Sold Put Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap Price / mmbtu	Additional Swap Volume (mmbtu/d) [2]
NBP												
3-Way Collar	Jan 2019 - Dec 2019		EUR	17,197	4.97	17,197	5.65	17,197	3.79	—	—	—
3-Way Collar	Jan 2019 - Dec 2020		EUR	7,370	4.96	7,370	5.76	7,370	3.74	—	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	17,197	4.91	17,197	5.70	17,197	3.87	—	—	—
Collar	Oct 2018 - Mar 2019		EUR	3,685	6.40	2,457	7.62	—	—	—	—	—
Call	Oct 2018 - Mar 2019		EUR	—	—	12,327	6.28	—	—	—	—	—
Swap	Oct 2018 - Mar 2019		EUR	—	—	—	—	—	—	4,913	7.92	—
Swaption	Jul 2019 - Jun 2021	Jun 28, 2019	EUR	—	—	—	—	—	—	9,827	5.64	—
Swaption	Oct 2019 - Mar 2020	Jun 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86	—
Swaption	Oct 2020 - Mar 2021	Jun 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86	—
Swaption	Oct 2021 - Mar 2022	Jun 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86	—
Collar	Jan 2018 - Dec 2018		GBP	2,500	3.15	2,500	3.82	—	—	—	—	—
Swap	Jan 2018 - Dec 2018		GBP	—	—	—	—	—	—	2,500	4.04	5,000
NBP Basis (NBP less NYMEX HH)												
Collar	Jan 2018 - Dec 2018		USD	2,500	1.85	2,500	4.00	—	—	—	—	—
Collar	Jan 2019 - Sep 2020		USD	7,500	2.07	7,500	4.00	—	—	—	—	—
TTF												
3-Way Collar	Oct 2017 - Dec 2019		EUR	7,370	4.59	7,370	5.42	7,370	2.93	—	—	—
3-Way Collar	Jan 2018 - Dec 2018		EUR	12,284	4.75	12,284	5.48	12,284	3.25	—	—	—
3-Way Collar	Jan 2018 - Dec 2019		EUR	3,685	4.74	3,685	5.52	3,685	3.13	—	—	—
3-Way Collar	Jan 2019 - Dec 2019		EUR	12,284	5.05	12,284	5.72	12,284	3.69	—	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—	—
Collar	Jan 2018 - Dec 2018		EUR	4,913	4.40	4,913	5.31	—	—	—	—	—
Swap	Oct 2017 - Dec 2018		EUR	—	—	—	—	—	—	17,197	4.80	—
Swap	Oct 2017 - Dec 2019		EUR	—	—	—	—	—	—	7,370	4.87	—
Swap	Jan 2018 - Dec 2019		EUR	—	—	—	—	—	—	1,228	5.00	—
Swap	Jul 2018 - Dec 2019		EUR	—	—	—	—	—	—	4,913	4.98	—
Swap	Jan 2019 - Dec 2019		EUR	—	—	—	—	—	—	2,457	4.92	—

Cross Currency Interest Rate		Receive Notional Amount (USD)	Rate (LIBOR +)	Pay Notional Amount (CAD)	Rate (CDOR +)
Swap	Oct 2018	994,814,456	1.70%	1,284,900,000	1.33%

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

(2) On the last business day of each month, the counterparty has the option to increase the contracted volumes for the following month.

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Q3 2018	Q2 2018	Q3 2017	YTD 2018	YTD 2017
Drilling and development	**142,116**	76,709	75,837	**343,483**	228,682
Exploration and evaluation	**4,069**	3,275	15,545	**11,151**	17,464
Capital expenditures	**146,185**	79,984	91,382	**354,634**	246,146

Acquisitions	**193,677**	57,590	20,976	**307,622**	24,589
Shares issued for acquisition	**—**	1,235,221	—	**1,235,221**	—
Long-term debt net of working capital assumed	**4,496**	172,674	—	**213,893**	—
Acquisitions	**198,173**	1,465,485	20,976	**1,756,736**	24,589

By category ($M)	Q3 2018	Q2 2018	Q3 2017	YTD 2018	YTD 2017
Drilling, completion, new well equip and tie-in, workovers and recompletions	**118,317**	56,154	62,451	**283,364**	180,135
Production equipment and facilities	**26,964**	10,224	16,982	**53,330**	41,520
Seismic, studies, land and other	**904**	13,606	11,949	**17,940**	24,491
Capital expenditures	**146,185**	79,984	91,382	**354,634**	246,146
Acquisitions	**198,173**	1,465,485	20,976	**1,756,736**	24,589
Total capital expenditures and acquisitions	**344,358**	1,545,469	112,358	**2,111,370**	270,735

Capital expenditures by country ($M)	Q3 2018	Q2 2018	Q3 2017	YTD 2018	YTD 2017
Canada	**89,837**	28,694	43,746	**187,646**	121,802
France	**15,779**	17,044	15,756	**62,750**	53,354
Netherlands	**5,056**	6,695	11,590	**15,029**	19,275
Germany	**6,497**	2,314	3,020	**11,226**	4,252
Ireland	**(50)**	87	1,101	**84**	224
Australia	**16,061**	11,368	10,154	**31,878**	22,750
United States	**11,386**	10,702	1,362	**37,956**	18,056
Corporate	**1,619**	3,080	4,653	**8,065**	6,433
Total capital expenditures	**146,185**	79,984	91,382	**354,634**	246,146

Acquisitions by country ($M)	Q3 2018	Q2 2018	Q3 2017	YTD 2018	YTD 2017
Canada	**6,146**	1,465,335	19,712	**1,561,731**	21,223
Netherlands	**2,874**	139	14	**5,773**	14
Germany	**959**	—	—	**959**	—
United States	**187,987**	11	1,250	**188,066**	3,312
Corporate	**207**	—	—	**207**	40
Total acquisitions	**198,173**	1,465,485	20,976	**1,756,736**	24,589

Supplemental Table 4: Production

	Q3/18	Q2/18	Q1/18	Q4/17	Q3/17	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15
Canada												
Crude oil & condensate (bbls/d)	**28,477**	17,009	9,272	9,703	9,288	9,205	7,987	7,945	8,984	9,453	10,317	10,413
NGLs (bbls/d)	**6,126**	5,589	5,106	5,235	4,891	3,745	2,670	2,444	2,448	2,687	2,633	2,710
Natural gas (mmcf/d)	**136.77**	127.32	106.21	107.91	103.92	93.68	85.74	75.12	77.62	87.44	97.16	87.90
Total (boe/d)	**57,397**	43,817	32,078	32,923	31,499	28,563	24,947	22,910	24,368	26,713	29,141	27,773
% of consolidated	**59%**	55%	46%	45%	46%	43%	38%	38%	37%	42%	44%	45%
France												
Crude oil (bbls/d)	**11,407**	11,683	11,037	11,215	10,918	11,368	10,834	11,220	11,827	12,326	12,220	12,537
Natural gas (mmcf/d)	**—**	—	—	—	—	—	0.01	0.38	0.42	0.54	0.44	1.36
Total (boe/d)	**11,407**	11,683	11,037	11,215	10,918	11,368	10,836	11,283	11,897	12,416	12,293	12,763
% of consolidated	**12%**	14%	16%	15%	16%	17%	17%	19%	19%	19%	19%	21%
Netherlands												
Condensate (bbls/d)	**84**	87	77	105	74	104	76	57	86	96	114	110
Natural gas (mmcf/d)	**44.37**	43.49	44.79	55.66	34.90	31.58	39.92	41.15	47.62	49.18	53.40	56.34
Total (boe/d)	**7,479**	7,335	7,541	9,381	5,890	5,368	6,729	6,915	8,023	8,293	9,015	9,500
% of consolidated	**8%**	9%	11%	13%	9%	8%	10%	11%	13%	13%	14%	16%
Germany												
Crude oil (bbls/d)	**1,019**	1,008	1,078	1,148	1,054	1,047	989	—	—	—	—	—
Natural gas (mmcf/d)	**14.88**	14.63	16.19	18.19	20.12	19.86	19.39	14.80	14.52	14.31	15.96	16.17
Total (boe/d)	**3,498**	3,447	3,777	4,180	4,407	4,357	4,220	2,467	2,420	2,385	2,660	2,695
% of consolidated	**4%**	4%	5%	6%	7%	6%	7%	4%	4%	4%	4%	4%
Ireland												
Natural gas (mmcf/d)	**51.38**	56.56	60.87	56.23	49.04	63.81	64.82	62.92	59.28	47.26	33.90	0.12
Total (boe/d)	**8,563**	9,426	10,144	9,372	8,173	10,634	10,803	10,486	9,879	7,877	5,650	20
% of consolidated	**9%**	12%	14%	13%	12%	16%	17%	17%	16%	12%	9%	—
Australia												
Crude oil (bbls/d)	**4,704**	4,132	4,971	4,993	5,473	6,054	6,581	6,388	6,562	6,083	6,180	7,824
% of consolidated	**5%**	5%	7%	7%	8%	9%	10%	10%	10%	9%	9%	13%
United States												
Crude oil (bbls/d)	**1,461**	655	574	667	880	747	365	362	383	458	368	420
NGLs (bbls/d)	**714**	62	20	43	56	76	24	23	30	26	39	29
Natural gas (mmcf/d)	**4.82**	0.40	0.15	0.29	0.64	0.44	0.20	0.18	0.20	0.20	0.26	0.20
Total (boe/d)	**2,979**	784	618	758	1,043	896	422	414	447	518	450	483
% of consolidated	**3%**	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%
Corporate												
Natural gas (mmcf/d)	**1.17**	—	—	—	—	—	—	—	—	—	—	—
Total (boe/d)	**195**	—	—	—	—	—	—	—	—	—	—	—
% of consolidated	**—**	—	—	—	—	—	—	—	—	—	—	—
Consolidated												
Liquids (bbls/d)	**53,991**	40,225	32,134	33,109	32,634	32,346	29,526	28,439	30,320	31,129	31,871	34,043
% of consolidated	**56%**	50%	46%	45%	48%	48%	46%	47%	48%	48%	49%	56%
Natural gas (mmcf/d)	**253.38**	242.40	228.20	238.28	208.62	209.36	210.07	194.54	199.65	198.93	201.11	162.09
% of consolidated	**44%**	50%	54%	55%	52%	52%	54%	53%	52%	52%	51%	44%
Total (boe/d)	**96,222**	80,625	70,167	72,821	67,403	67,240	64,537	60,863	63,596	64,285	65,389	61,058

	YTD 2018	2017	2016	2015	2014	2013
Canada						
Crude oil & condensate (bbls/d)	**18,323**	9,051	9,171	11,357	12,491	8,387
NGLs (bbls/d)	**5,611**	4,144	2,552	2,301	1,233	1,666
Natural gas (mmcf/d)	**123.54**	97.89	84.29	71.65	55.67	42.39
Total (boe/d)	**44,524**	29,510	25,771	25,598	23,001	17,117
% of consolidated	**54%**	45%	40%	46%	47%	41%
France						
Crude oil (bbls/d)	**11,377**	11,084	11,896	12,267	11,011	10,873
Natural gas (mmcf/d)	**—**	—	0.44	0.97	—	3.40
Total (boe/d)	**11,377**	11,085	11,970	12,429	11,011	11,440
% of consolidated	**14%**	16%	19%	23%	22%	28%
Netherlands						
Condensate (bbls/d)	**83**	90	88	99	77	64
Natural gas (mmcf/d)	**44.21**	40.54	47.82	44.76	38.20	35.42
Total (boe/d)	**7,452**	6,847	8,058	7,559	6,443	5,967
% of consolidated	**9%**	10%	13%	14%	13%	15%
Germany						
Crude oil (bbls/d)	**1,035**	1,060	—	—	—	—
Natural gas (mmcf/d)	**15.23**	19.39	14.90	15.78	14.99	—
Total (boe/d)	**3,573**	4,291	2,483	2,630	2,498	—
% of consolidated	**4%**	6%	4%	5%	5%	—
Ireland						
Natural gas (mmcf/d)	**56.23**	58.43	50.89	0.03	—	—
Total (boe/d)	**9,372**	9,737	8,482	5	—	—
% of consolidated	**11%**	14%	13%	—	—	—
Australia						
Crude oil (bbls/d)	**4,601**	5,770	6,304	6,454	6,571	6,481
% of consolidated	**6%**	8%	10%	12%	13%	16%
United States						
Crude oil (bbls/d)	**900**	666	393	231	49	—
NGLs (bbls/d)	**268**	50	29	7	—	—
Natural gas (mmcf/d)	**1.81**	0.39	0.21	0.05	—	—
Total (boe/d)	**1,469**	781	457	247	49	—
% of consolidated	**2%**	1%	1%	—	—	—
Corporate						
Natural gas (mmcf/d)	**0.39**	—	—	—	—	—
Total (boe/d)	**66**	—	—	—	—	—
% of consolidated	**—**	—	—	—	—	—
Consolidated						
Liquids (bbls/d)	**42,196**	31,915	30,433	32,716	31,432	27,471
% of consolidated	**51%**	47%	48%	60%	63%	67%
Natural gas (mmcf/d)	**241.42**	216.64	198.55	133.24	108.85	81.21
% of consolidated	**49%**	53%	52%	40%	37%	33%
Total (boe/d)	**82,433**	68,021	63,526	54,922	49,573	41,005

Supplemental Table 5: Q1 and Q2 2018 Netbacks Adjusted for IFRS 16

The following table includes financial statement information on a per unit basis by business unit for Q1 and Q2 2018 after adjusting for the impact of the application of IFRS 16. Please refer to "Recently Adopted Accounting Pronouncements" for further information. 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 2018			Q2 2018		
	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Liquids $/bbl	Natural Gas $/mcf	Total $/boe
Canada						
Sales	57.39	1.95	32.19	66.27	1.09	37.35
Royalties	(7.34)	(0.04)	(3.41)	(8.86)	0.24	(3.88)
Transportation	(2.38)	(0.15)	(1.57)	(1.65)	(0.16)	(1.30)
Operating	(8.94)	(1.31)	(8.35)	(11.13)	(1.11)	(8.97)
Operating netback	38.73	0.45	18.86	44.63	0.06	23.20
General and administration			(0.24)			(0.47)
Fund flows from operations netback			18.62			22.73
France						
Sales	81.70	—	81.70	95.13	—	95.13
Royalties	(10.60)	—	(10.60)	(11.85)	—	(11.85)
Transportation	(2.65)	—	(2.65)	(2.65)	—	(2.65)
Operating	(14.66)	—	(14.66)	(13.07)	—	(13.07)
Operating netback	53.79	—	53.79	67.56	—	67.56
General and administration			(3.95)			(3.29)
Current income taxes			(2.31)			(4.92)
Fund flows from operations netback			47.53			59.35
Netherlands						
Sales	68.64	8.86	53.31	79.40	8.68	52.43
Royalties	—	(0.21)	(1.25)	—	(0.19)	(1.12)
Operating	—	(1.91)	(11.32)	—	(1.62)	(9.62)
Operating netback	68.64	6.74	40.74	79.40	6.87	41.69
General and administration			(1.14)			(0.22)
Current income taxes			(8.55)			(7.48)
Fund flows from operations netback			31.05			33.99
Germany						
Sales	79.04	7.69	56.86	91.00	7.68	59.69
Royalties	(2.53)	(0.99)	(4.82)	(2.22)	(0.78)	(3.93)
Transportation	(9.80)	(0.58)	(5.54)	(10.17)	(0.60)	(5.59)
Operating	(22.08)	(2.46)	(17.16)	(22.36)	(2.43)	(16.92)
Operating netback	44.63	3.66	29.34	56.25	3.87	33.25
General and administration			(4.32)			(4.59)
Fund flows from operations netback			25.02			28.66
Ireland						
Sales	—	9.80	58.79	—	9.30	55.80
Transportation	—	(0.23)	(1.41)	—	(0.25)	(1.48)
Operating	—	(0.59)	(3.51)	—	(0.84)	(5.02)
Operating netback	—	8.98	53.87	—	8.21	49.30
General and administration			(1.43)			(1.68)
Fund flows from operations netback			52.44			47.62

	Q1 2018			Q2 2018		
	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Liquids $/bbl	Natural Gas $/mcf	Total $/boe
Australia						
Sales	86.94	—	86.94	98.61	—	98.61
Operating	(29.72)	—	(29.72)	(33.81)	—	(33.81)
PRRT (1)	(11.04)	—	(11.04)	(7.00)	—	(7.00)
Operating netback	46.18	—	46.18	57.80	—	57.80
General and administration			(3.47)			(2.59)
Corporate income taxes			(1.53)			(6.21)
Fund flows from operations netback			41.18			49.00
United States						
Sales	75.20	3.00	72.94	79.24	1.59	73.30
Royalties	(20.72)	(1.08)	(20.16)	(21.92)	(0.57)	(20.35)
Transportation	—	—	—	—	—	—
Operating	(10.60)	—	(10.18)	(5.73)	—	(5.24)
Operating netback	43.88	1.92	42.60	51.59	1.02	47.71
General and administration			(21.13)			(18.74)
Fund flows from operations netback			21.47			28.97
Total Company						
Sales	71.03	5.81	51.13	78.89	4.77	53.72
Realized hedging loss	(3.24)	(0.42)	(2.85)	(6.08)	(0.25)	(3.79)
Royalties	(7.26)	(0.13)	(3.69)	(8.85)	0.04	(4.29)
Transportation	(2.35)	(0.17)	(1.64)	(1.96)	(0.18)	(1.50)
Operating	(14.57)	(1.32)	(10.90)	(14.21)	(1.22)	(10.75)
PRRT (1)	(1.73)	—	(0.78)	(0.72)	—	(0.36)
Operating netback	41.88	3.77	31.27	47.07	3.16	33.03
General and administration			(1.88)			(1.93)
Interest expense			(2.50)			(2.26)
Realized foreign exchange gain (loss)			0.25			(0.56)
Other income			0.03			0.03
Corporate income taxes			(1.40)			(1.73)
Fund flows from operations netback			25.77			26.58

(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.

Non-GAAP Financial Measures

This MD&A includes references to certain financial measures which do not have standardized meanings and may not be comparable to similar measures presented by other issuers. These financial measures include fund flows from operations, a measure of profit or loss in accordance with IFRS 8 “Operating Segments” (please see Segmented Information in the Notes to the Condensed Consolidated Financial Statements) and net debt, a measure of capital in accordance with IAS 1 “Presentation of Financial Statements” (please see Capital Disclosures in the Notes to the Condensed Consolidated Financial Statements).

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

Acquisitions: The sum of acquisitions from the Consolidated Statement of Cash Flows plus the assumption of the acquiree's outstanding long-term debt plus or net of acquired working capital deficit or surplus.

Capital expenditures: The sum of drilling and development and exploration and evaluation from the Consolidated Statement 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 VIP as determined using the treasury stock method.

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

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

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

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

($M)	Q3 2018	Q2 2018	Q3 2017	YTD 2018	YTD 2017
Dividends declared	**105,192**	98,604	78,293	**282,801**	232,744
Shares issued for the Dividend Reinvestment Plan	**(4,320)**	(19,975)	(23,929)	**(43,936)**	(88,676)
Net dividends	**100,872**	78,629	54,364	**238,865**	144,068
Drilling and development	**142,116**	76,709	75,837	**343,483**	228,682
Exploration and evaluation	**4,069**	3,275	15,545	**11,151**	17,464
Asset retirement obligations settled	**2,986**	2,626	1,749	**9,203**	6,118
Payout	**250,043**	161,239	147,495	**602,702**	396,332
% of fund flows from operations	**96%**	83%	113%	**98%**	94%

('000s of shares)	Q3 2018	Q2 2018	Q3 2017
Shares outstanding	**152,497**	152,363	121,585
Potential shares issuable pursuant to the VIP	**3,250**	2,992	2,868
Diluted shares outstanding	**155,747**	155,355	124,453

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

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

Carin Knickel [6, 8]
Golden, Colorado

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

Loren M. Leiker [10]
Houston, Texas

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

Anthony Marino
Calgary, Alberta

Robert Michaleski [4, 5]
Calgary, Alberta

William Roby [8, 9]
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

ABBREVIATIONS

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

OFFICERS AND KEY PERSONNEL

CANADA

Anthony Marino
President & Chief Executive Officer

Lars Glemser
Vice President & Chief Financial Officer

Mona Jasinski
Executive Vice President, People and Culture

Michael Kaluza
Executive Vice President & Chief Operating Officer

Dion Hatcher
Vice President Canada Business Unit

Terry Hergott
Vice President Marketing

Jenson Tan
Vice President Business Development

Daniel Goulet
Director Corporate HSE

Jeremy Kalanuk
Director Operations Accounting

Bryce Kremnica
Director Field Operations - Canada Business Unit

Kyle Preston
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

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

National Bank of Canada

The Bank of Nova Scotia

Royal Bank of Canada

Alberta Treasury Branches

Bank of America N.A., Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

HSBC Bank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian Branch

Barclays Bank PLC

Canadian Western Bank

Goldman Sachs Lending Partners LLC

Export Development Canada

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TRANSFER AGENT

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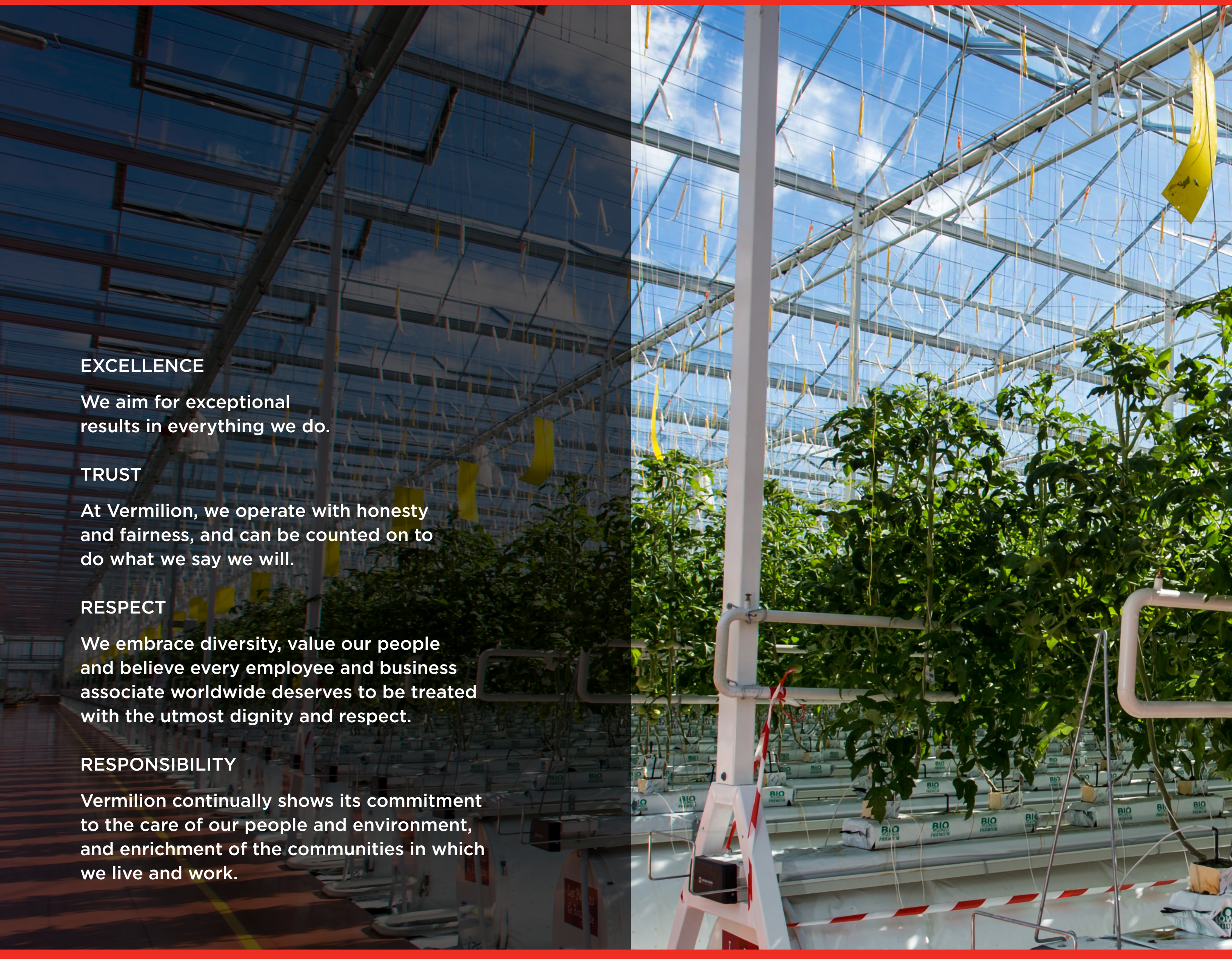

EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

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