Q2 2017

VERMILION
ENERGY

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A"), dated July 25, 2017, of Vermilion Energy Inc.'s ("Vermilion", "We", "Our", "Us" or the "Company") operating and financial results as at and for the three and six months ended June 30, 2017 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 six months ended June 30, 2017 and the audited consolidated financial statements for the year ended December 31, 2016 and 2015, together with 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 six months ended June 30, 2017 and comparative information have been prepared in Canadian dollars, except where another currency is indicated, and in accordance with IAS 34, "Interim Financial Reporting", as issued by the International Accounting Standard 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".

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.

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).

2017 GUIDANCE

On October 31, 2016, we released our 2017 capital expenditure guidance of $295 million and associated production guidance of between 69,000-70,000 boe/d. On July 26, 2017 we announced an increase in our capital expenditure guidance from $295 million to $315 million following the acceleration of 2018 activities in our Canadian business unit.

The following table summarizes our guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2017 Guidance			
2017 Guidance	October 31, 2016	295	69,000 to 70,000
2017 Guidance	July 26, 2017	315	69,000 to 70,000

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change		Six Months Ended		% change
	Jun 30, 2017	**Mar 31, 2017**	**Jun 30, 2016**	**Q2/17 vs. Q1/17**	**Q2/17 vs. Q2/16**	**Jun 30, 2017**	**Jun 30, 2016**	**2017 vs. 2016**
Production								
Crude oil and condensate (bbls/d)	**28,525**	26,832	28,416	6%	-	**27,683**	28,808	(4%)
NGLs (bbls/d)	**3,821**	2,694	2,713	42%	41%	**3,260**	2,693	21%
Natural gas (mmcf/d)	**209.36**	210.07	198.93	-	5%	**209.71**	200.02	5%
Total (boe/d)	**67,240**	64,537	64,285	4%	5%	**65,896**	64,837	2%
Sales								
Crude oil and condensate (bbls/d)	**29,639**	24,218	27,644	22%	7%	**26,943**	27,646	(3%)
NGLs (bbls/d)	**3,821**	2,694	2,713	42%	41%	**3,260**	2,693	21%
Natural gas (mmcf/d)	**209.36**	210.07	198.93	-	5%	**209.71**	200.02	5%
Total (boe/d)	**68,355**	61,923	63,514	10%	8%	**65,157**	63,676	2%
Build (draw) in inventory (mbbls)	**(102)**	235	70			**133**	212	
Financial metrics								
Fund flows from operations ($M)	**147,123**	143,434	126,568	3%	16%	**290,557**	220,235	32%
Per share ($/basic share)	**1.22**	1.21	1.10	1%	11%	**2.43**	1.93	26%
Net earnings (loss)	**48,264**	44,540	(55,696)	8%	N/A	**92,804**	(141,544)	N/A
Per share ($/basic share)	**0.40**	0.38	(0.48)	5%	N/A	**0.78**	(1.24)	N/A
Net debt ($M)	**1,314,766**	1,377,636	1,398,950	(5%)	(6%)	**1,314,766**	1,398,950	(6%)
Cash dividends ($/share)	**0.645**	0.645	0.645	-	-	**1.290**	1.290	-
Activity								
Capital expenditures ($M)	**58,875**	95,889	71,714	(39%)	(18%)	**154,764**	134,487	15%
Acquisitions ($M)	**993**	2,620	8,550	(62%)	(88%)	**3,613**	9,420	(62%)
Gross wells drilled	**2.00**	29.00	4.00			**31.00**	16.00	
Net wells drilled	**1.40**	25.41	3.14			**26.81**	11.40	

Operational review

- Consolidated average production increased by 4% in Q2 2017 versus Q1 2017. This increase in production was primarily attributable to higher volumes in Canada, France, and the US.
- Consolidated average production increased by 5% and 2% for the three and six months ended June 30, 2017, versus the comparable periods in 2016. This increase was primarily due to increased production in Ireland, as well as incremental volumes from our acquisition in Germany that closed in late 2016.
- For the three months ended June 30, 2017, capital expenditures of $58.9 million related primarily to Canada, France, and Australia. In Canada, capital expenditures of $20.6 million related primarily to completion and tie-in activities for wells drilled in the prior quarter. In France, capital expenditures of $16.7 million largely related to a subsurface and workover program. In Australia, capital expenditures of $9.2 million related primarily to improvements to oil and water processing capacity at our Wandoo B platform.

Financial review

Net earnings

- Net earnings for Q2 2017 was $48.3 million ($0.40/basic share), an 8% increase from net earnings of $44.5 million ($0.38/basic share) in Q1 2017. The increase in net earnings was primarily due to higher revenue resulting from higher sales volumes and a $38.6 million unrealized foreign exchange gain due to the strengthening of the Euro relative to the Canadian dollar.
- Net earnings for the three and six months ended June 30, 2017 of $48.3 million ($0.40/basic share) and $92.8 million ($0.78/basic share), respectively, compared to net losses of $55.7 million ($0.48/basic share) and $141.5 million ($1.24/basic share) in the comparable periods in 2016. The change in net earnings was primarily attributable to higher revenue as a result of higher commodity prices, as well as the impact of unrealized gains on derivative instruments and foreign exchange.

Fund flows from operations

- Generated fund flows from operations of $147.1 million during Q2 2017, an increase of 3% from Q1 2017. This quarter-over-quarter increase occurred despite lower commodity prices due to higher sales volumes in Australia and France which was a result of favourable inventory variances and higher production in Canada.
- Fund flows from operations increased by 16% and 32% for the three and six months ended June 30, 2017, driven by higher commodity prices and higher sales volumes in Ireland, Germany, and Australia.

Net debt

- Net debt decreased to $1.31 billion as at June 30, 2017 from $1.43 billion at December 31, 2016 as fund flows from operations generated in excess of capital expenditures and net dividends was used to reduce long-term debt.

Dividends

- Declared dividends of $0.215 per common share per month during the six months ended June 30, 2017, totalling $1.29 per common share.

COMMODITY PRICES

	Three Months Ended			% change		Six Months Ended		% change
	Jun 30, 2017	Mar 31, 2017	Jun 30, 2016	Q2/17 vs. Q1/17	Q2/17 vs. Q2/16	Jun 30, 2017	Jun 30, 2016	2017 vs. 2016
Average reference prices								
Crude oil								
WTI (US $/bbl)	**48.28**	51.92	45.59	(7%)	6%	**50.10**	39.52	27%
Edmonton Sweet index (US $/bbl)	**46.03**	48.37	42.51	(5%)	8%	**47.20**	36.13	31%
Dated Brent (US $/bbl)	**49.83**	53.78	45.57	(7%)	9%	**51.81**	39.73	30%
Natural gas								
AECO ($/mmbtu)	**2.78**	2.69	1.40	3%	99%	**2.74**	1.61	70%
NBP ($/mmbtu)	**6.52**	7.96	5.78	(18%)	13%	**7.26**	5.88	23%
NBP (€/mmbtu)	**4.41**	5.64	3.97	(22%)	11%	**5.02**	3.96	27%
TTF ($/mmbtu)	**6.74**	7.65	5.61	(12%)	20%	**7.21**	5.66	27%
TTF (€/mmbtu)	**4.56**	5.43	3.86	(16%)	18%	**4.99**	3.81	31%
Henry Hub ($/mmbtu)	**4.28**	4.38	2.52	(2%)	70%	**4.33**	2.69	61%
Henry Hub (US $/mmbtu)	**3.18**	3.31	1.95	(4%)	63%	**3.25**	2.02	61%
Average foreign currency exchange rates								
CDN $/US $	**1.34**	1.32	1.29	2%	4%	**1.33**	1.33	-
CDN $/Euro	**1.48**	1.41	1.46	5%	1%	**1.44**	1.49	(3%)

- While crude oil prices for the six months ended June 30, 2017 were significantly higher than the 2016 period, they have been volatile during the comparative quarters presented. Crude oil prices in Q2 2017 were 5% to 7% lower than Q1 2017 but 6% to 9% higher than Q2 2016.
- Field maintenance, strong early quarter US exports, and domestic demand resulted in increased AECO prices of 3% versus Q1 2017 and 99% versus Q2 2016.
- Weaker demand, increasing liquefied natural gas imports, and issues related to the UK's Rough storage facility resulted in weaker European natural gas prices in Q2 2017 as compared to Q1 2017.
- In Q2 2017, the Canadian dollar weakened slightly against both the US dollar and the Euro as compared to Q1 2017.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Six Months Ended			
	Jun 30, 2017		Mar 31, 2017		Jun 30, 2016		Jun 30, 2017		Jun 30, 2016	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	**271,391**	**43.63**	261,601	46.94	212,855	36.83	**532,992**	**45.19**	390,240	33.67
Royalties	**(17,736)**	**(2.85)**	(16,205)	(2.91)	(12,355)	(2.14)	**(33,941)**	**(2.88)**	(26,316)	(2.27)
Petroleum and natural gas revenues	**253,655**	**40.78**	245,396	44.03	200,500	34.69	**499,051**	**42.31**	363,924	31.40
Transportation	**(10,843)**	**(1.74)**	(9,819)	(1.76)	(9,860)	(1.71)	**(20,662)**	**(1.75)**	(20,250)	(1.75)
Operating	**(63,074)**	**(10.14)**	(52,121)	(9.35)	(52,116)	(9.02)	**(115,195)**	**(9.77)**	(107,744)	(9.30)
General and administration	**(13,167)**	**(2.12)**	(13,151)	(2.36)	(15,493)	(2.68)	**(26,318)**	**(2.23)**	(29,070)	(2.51)
PRRT	**(6,468)**	**(1.04)**	(5,434)	(0.97)	(144)	(0.02)	**(11,902)**	**(1.01)**	(272)	(0.02)
Corporate income taxes	**(4,047)**	**(0.65)**	(7,479)	(1.34)	(5,564)	(0.96)	**(11,526)**	**(0.98)**	(8,724)	(0.75)
Interest expense	**(15,508)**	**(2.49)**	(14,695)	(2.64)	(13,647)	(2.36)	**(30,203)**	**(2.56)**	(28,397)	(2.45)
Realized gain (loss) on derivatives	**5,342**	**0.86**	(1,851)	(0.33)	21,501	3.72	**3,491**	**0.30**	49,924	4.31
Realized foreign exchange gain	**981**	**0.16**	2,546	0.46	1,329	0.23	**3,527**	**0.30**	677	0.06
Realized other income	**252**	**0.04**	42	0.01	62	0.01	**294**	**0.02**	167	0.01
Fund flows from operations	**147,123**	**23.66**	143,434	25.75	126,568	21.90	**290,557**	**24.63**	220,235	19.00

The following table shows a reconciliation of the change in fund flows from operations:

($M)	**Q2/17 vs. Q1/17**	**Q2/17 vs. Q2/16**	**2017 vs. 2016**
Fund flows from operations – Comparative period	**143,434**	**126,568**	**220,235**
Sales volume variance:			
Canada	14,421	4,190	(6,757)
France	9,917	(1,972)	(13,418)
Netherlands	(5,110)	(8,396)	(15,641)
Germany	113	7,591	15,047
Ireland	(255)	8,143	23,262
Australia	16,939	7,722	8,514
United States	2,423	1,542	1,218
Pricing variance on sales volumes:			
WTI	(5,318)	5,331	29,096
AECO	(1,401)	12,750	20,539
Dated Brent	(10,137)	10,622	47,813
TTF and NBP	(11,802)	11,013	33,079
Changes in:			
Royalties	(1,531)	(5,381)	(7,625)
Transportation	(1,024)	(983)	(412)
Operating	(10,953)	(10,958)	(7,451)
General and administration	(16)	2,326	2,752
PRRT	(1,034)	(6,324)	(11,630)
Corporate income taxes	3,432	1,517	(2,802)
Interest	(813)	(1,861)	(1,806)
Realized derivatives	7,193	(16,159)	(46,433)
Realized foreign exchange	(1,565)	(348)	2,850
Realized other income	210	190	127
Fund flows from operations – Current period	**147,123**	**147,123**	**290,557**

Please see CONSOLIDATED RESULTS OVERVIEW for a discussion of the key variances for the periods presented.

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 significantly 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.

CANADA BUSINESS UNIT

Overview

- Production and assets focused in West Pembina near Drayton Valley, Alberta and Northgate in southeast Saskatchewan.
- Potential for three significant resource plays sharing the same surface infrastructure in the West Pembina region in Alberta:
  - Cardium light oil (1,800m depth) – in development phase
  - Mannville condensate-rich gas (2,400 – 2,700m depth) – in development phase
  - Duvernay condensate-rich gas (3,200 – 3,400m depth) – in appraisal phase with no investment at present
- Southeast Saskatchewan light oil development:
  - Primary target is the Mississippian Midale formation (1,400 – 1,700m depth)
  - Secondary targets of Mississippian Frobisher (1,400 – 1,700m depth) and Devonian Bakken/Three Forks (2,000 – 2,100m depth)

Operational and financial review

	Three Months Ended			% change		Six Months Ended		% change
Canada business unit ($M except as indicated)	**Jun 30, 2017**	**Mar 31, 2017**	**Jun 30, 2016**	**Q2/17 vs. Q1/17**	**Q2/17 vs. Q2/16**	**Jun 30, 2017**	**Jun 30, 2016**	**2017 vs. 2016**
Production and sales								
Crude oil and condensate (bbls/d)	**9,205**	7,987	9,453	15%	(3%)	**8,599**	9,885	(13%)
NGLs (bbls/d)	**3,745**	2,670	2,687	40%	39%	**3,210**	2,660	21%
Natural gas (mmcf/d)	**93.68**	85.74	87.44	9%	7%	**89.73**	92.30	(3%)
Total (boe/d)	**28,563**	24,947	26,713	14%	7%	**26,765**	27,928	(4%)
Production mix (% of total)								
Crude oil and condensate	**32%**	32%	35%			**32%**	35%	
NGLs	**13%**	11%	10%			**12%**	10%	
Natural gas	**55%**	57%	55%			**56%**	55%	
Activity								
Capital expenditures	**20,599**	57,457	5,619	(64%)	267%	**78,056**	35,390	121%
Acquisitions	**935**	576	796			**1,511**	1,551	
Gross wells drilled	**1.00**	22.00	2.00			**23.00**	14.00	
Net wells drilled	**0.40**	18.41	1.14			**18.81**	9.40	
Financial results								
Sales	**83,643**	75,500	61,731	11%	35%	**159,143**	117,841	35%
Royalties	**(8,805)**	(8,499)	(3,770)	4%	134%	**(17,304)**	(9,268)	87%
Transportation	**(3,944)**	(4,103)	(3,759)	(4%)	5%	**(8,047)**	(7,910)	2%
Operating	**(19,347)**	(16,670)	(16,460)	16%	18%	**(36,017)**	(37,803)	(5%)
General and administration	**(3,127)**	(1,698)	(4,305)	84%	(27%)	**(4,825)**	(6,781)	(29%)
Fund flows from operations	**48,420**	44,530	33,437	9%	45%	**92,950**	56,079	66%
Netbacks ($/boe)								
Sales	**32.18**	33.63	25.39	(4%)	27%	**32.85**	23.18	42%
Royalties	**(3.39)**	(3.79)	(1.55)	(11%)	119%	**(3.57)**	(1.82)	96%
Transportation	**(1.52)**	(1.83)	(1.55)	(17%)	(2%)	**(1.66)**	(1.56)	6%
Operating	**(7.44)**	(7.42)	(6.77)	-	10%	**(7.43)**	(7.44)	-
General and administration	**(1.20)**	(0.76)	(1.77)	58%	(32%)	**(1.00)**	(1.33)	(25%)
Fund flows from operations netback	**18.63**	19.83	13.75	(6%)	35%	**19.19**	11.03	74%
Realized prices								
Crude oil and condensate ($/bbl)	**62.46**	64.76	56.67	(4%)	10%	**63.52**	47.81	33%
NGLs ($/bbl)	**21.11**	24.12	9.56	(12%)	121%	**22.35**	8.45	164%
Natural gas ($/mmbtu)	**2.83**	2.99	1.34	(5%)	111%	**2.91**	1.65	76%
Total ($/boe)	**32.18**	33.63	25.39	(4%)	27%	**32.85**	23.18	42%
Reference prices								
WTI (US $/bbl)	**48.28**	51.92	45.59	(7%)	6%	**50.10**	39.52	27%
Edmonton Sweet index (US $/bbl)	**46.03**	48.37	42.51	(5%)	8%	**47.20**	36.13	31%
Edmonton Sweet index ($/bbl)	**61.90**	63.99	54.78	(3%)	13%	**62.96**	48.11	31%
AECO ($/mmbtu)	**2.78**	2.69	1.40	3%	99%	**2.74**	1.61	70%

Production

- Q2 2017 average production increased by 14% from Q1 2017 primarily due to organic production growth in our Mannville condensate-rich gas resource play and organic production growth in southeast Saskatchewan. On a year-over-year basis, production increased 7% as a result of strong organic production growth in the Mannville.
- Mannville production averaged approximately 14,700 boe/d in Q2 2017 representing a 23% increase quarter-over-quarter.
- Cardium production averaged approximately 5,700 boe/d in Q2 2017, in line with prior quarter.
- Production from southeast Saskatchewan averaged approximately 2,900 boe/d in Q2 2017, an increase of 45% quarter-over-quarter.

Activity review

- Vermilion did not drill any operated wells in the second quarter and participated in the drilling of one (0.4 net) non-operated well.

  Mannville
  - During Q2 2017, we brought four (3.2 net) operated wells on production. We participated in the drilling of one (0.4 net) non-operated well.
  - In 2017, we plan to drill or participate in 23 (16.3 net) wells.

  Cardium
  - In Q2 2017, we brought three (3.0 net) operated wells on production.
  - Our 2017 program has been expanded to drill seven (7.0 net) wells.

  Saskatchewan
  - In Q2 2017 we brought five (5.0 net) operated wells on production and placed one (0.3 net) non-operated wells on production.
  - In 2017, we plan to drill or participate in 13 (11.3 net) wells.

Sales

- The realized price for our crude oil and condensate production in Canada is linked to WTI, and is also subject to market conditions in western Canada. These market conditions can result in fluctuations in the pricing differential to WTI, as reflected by the Edmonton Sweet index price. The realized price of our NGLs in Canada is based on product specific differentials pertaining to trading hubs in the United States. The realized price of our natural gas in Canada is based on the AECO index in Canada.
- Q2 2017 sales per boe decreased compared to Q1 2017 due to lower crude oil pricing.
- For the three and six months ended June 30, 2017, sales per boe increased versus the comparable periods in 2016 as a result of higher average crude oil and natural gas pricing.

Royalties

- In Q2 2017, royalties as a percentage of sales decreased to 10.5% from 11.3% in Q1 2017 due to the impact of a favourable gas cost allowance adjustment in Alberta in Q2 2017.
- For the three and six months ended June 30, 2017, royalties as a percentage of sales increased to 10.5% and 10.9%, respectively, compared to 6.1% and 7.9% in the comparable periods in the prior year due to the impact of higher commodity prices on the sliding scale used to determine royalty rates.

Transportation

- Transportation expense relates to the delivery of crude oil and natural gas production to major pipelines where legal title transfers.
- In Q2 2017, transportation expense on a per unit basis decreased compared to Q1 2017 due to the absence of a prior period adjustment that was recorded in Q1 2017. Absent this prior period adjustment, transportation expense was relatively consistent quarter-over-quarter. On a dollar basis, transportation expense was relatively consistent with Q1 2017 as higher volumes in Q2 2017 offset the impact of the prior period adjustment recorded in the prior quarter.
- For the three and six months ended June 30, 2017, transportation expense on a per unit and dollar basis were relatively consistent with the comparable periods in 2016.

Operating

- In Q2 2017, operating expense on a per unit basis was relatively consistent with Q1 2017. Operating expense on a dollar basis increased compared to Q1 2017 as a result of higher volumes.
- Operating expense was higher on a per unit and dollar basis in Q2 2017 versus Q2 2016 due to expenditure timing. For the six months ended June 30, 2017, operating expense was relatively consistent on a per unit basis as compared to the same period in the prior year. On a dollar basis, operating expense decreased modestly year-over-year due to lower volumes.

General and administration

- The increase in general and administration expense for Q2 2017 as compared to Q1 2017 was primarily the result of expenditure timing.
- For the three and six months ended June 30, 2017, the decreases in general and administration expense versus the comparable periods in the prior year were due to ongoing initiatives to reduce our cost structure.

Current income taxes

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

FRANCE BUSINESS UNIT

Overview

- Entered France in 1997 and completed three subsequent acquisitions, including two in 2012.
- 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

	Three Months Ended			% change		Six Months Ended		% change
France business unit ($M except as indicated)	**Jun 30, 2017**	**Mar 31, 2017**	**Jun 30, 2016**	**Q2/17 vs. Q1/17**	**Q2/17 vs. Q2/16**	**Jun 30, 2017**	**Jun 30, 2016**	**2017 vs. 2016**
Production								
Crude oil (bbls/d)	**11,368**	10,834	12,326	5%	(8%)	**11,103**	12,273	(10%)
Natural gas (mmcf/d)	**-**	0.01	0.54	(100%)	(100%)	**-**	0.49	(100%)
Total (boe/d)	**11,368**	10,836	12,416	5%	(8%)	**11,103**	12,354	(10%)
Sales								
Crude oil (bbls/d)	**11,259**	9,760	11,616	15%	(3%)	**10,514**	11,899	(12%)
Natural gas (mmcf/d)	**-**	0.01	0.54	(100%)	(100%)	**-**	0.49	(100%)
Total (boe/d)	**11,259**	9,761	11,706	15%	(4%)	**10,514**	11,980	(12%)
Inventory (mbbls)								
Opening crude oil inventory	**245**	148	247			**148**	243	
Crude oil production	**1,034**	975	1,122			**2,010**	2,234	
Crude oil sales	**(1,025)**	(878)	(1,057)			**(1,904)**	(2,165)	
Closing crude oil inventory	**254**	245	312			**254**	312	
Activity								
Capital expenditures	**16,682**	20,916	12,772	(20%)	31%	**37,598**	26,235	43%
Gross wells drilled	**1.00**	4.00	-			**5.00**	-	
Net wells drilled	**1.00**	4.00	-			**5.00**	-	
Financial results								
Sales	**63,615**	59,610	61,591	7%	3%	**123,225**	109,716	12%
Royalties	**(6,247)**	(5,320)	(6,564)	17%	(5%)	**(11,567)**	(13,330)	(13%)
Transportation	**(3,686)**	(3,032)	(3,476)	22%	6%	**(6,718)**	(7,189)	(7%)
Operating	**(12,153)**	(11,369)	(11,265)	7%	8%	**(23,522)**	(25,585)	(8%)
General and administration	**(3,713)**	(3,070)	(4,734)	21%	(22%)	**(6,783)**	(9,410)	(28%)
Current income taxes	**(1,830)**	(4,982)	(921)	(63%)	99%	**(6,812)**	(955)	613%
Fund flows from operations	**35,986**	31,837	34,631	13%	4%	**67,823**	53,247	27%
Netbacks ($/boe)								
Sales	**62.09**	67.85	57.82	(8%)	7%	**64.75**	50.32	29%
Royalties	**(6.10)**	(6.06)	(6.16)	1%	(1%)	**(6.08)**	(6.11)	-
Transportation	**(3.60)**	(3.45)	(3.26)	4%	10%	**(3.53)**	(3.30)	7%
Operating	**(11.86)**	(12.94)	(10.57)	(8%)	12%	**(12.36)**	(11.73)	5%
General and administration	**(3.62)**	(3.49)	(4.44)	4%	(18%)	**(3.56)**	(4.32)	(18%)
Current income taxes	**(1.79)**	(5.67)	(0.86)	(68%)	108%	**(3.58)**	(0.44)	714%
Fund flows from operations	**35.12**	36.24	32.53	(3%)	8%	**35.64**	24.42	46%
Realized prices								
Crude oil ($/bbl)	**62.09**	67.86	58.19	(9%)	7%	**64.75**	50.60	28%
Natural gas ($/mmbtu)	**-**	1.52	1.58	(100%)	(100%)	**1.52**	1.62	(6%)
Total ($/boe)	**62.09**	67.85	57.82	(8%)	7%	**64.75**	50.32	29%
Reference prices								
Dated Brent (US $/bbl)	**49.83**	53.78	45.57	(7%)	9%	**51.81**	39.73	30%
Dated Brent ($/bbl)	**67.01**	71.15	58.72	(6%)	14%	**69.10**	52.91	31%

Production

- Q2 2017 production increased 5% versus the prior quarter due to production additions from our Champotran and Neocomian drilling programs. Production decreased by 8% versus Q2 2016 due to production declines, well downtime and third party restrictions impacting Vic Bilh gas production. These decreases more than offset new well production and optimization activities.

Activity review

- During Q2 2017 we drilled one (1.0 net) well in the Neocomian field, completing our first drilling program with all four (4.0 net) wells successfully brought on production.
- We have completed our drilling and completion activity for 2017, which included the drilling and completion of four (4.0 net) Neocomian wells and one (1.0 net) horizontal sidetrack well in the Vulaines field as well as the completion of four (4.0 net) Champotran wells that were drilled in Q4 2016.
- In addition to the drilling and completion activity, we will continue to focus on workover and optimization activities throughout the remainder of 2017.

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Q2 2017 sales per boe decreased versus Q1 2017 as a result of lower Dated Brent prices. The decrease in price was more than offset by higher sales volumes, resulting in an increase in sales.
- Sales per boe for the three and six months ended June 30, 2017 increased versus the comparable periods in 2016 due to stronger Dated Brent pricing. For the three and six months ended June 30, 2017, the increase in price was partially offset by lower sales volumes. Based on anticipated shipment schedules, we expect that the inventory build that occurred in the first half of 2017 will reverse over the course of the year.

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 9.8% in Q2 2017 was higher than 8.9% in Q1 2017 as a result of the impact of fixed RCDM royalties coupled with lower realized pricing in the quarter.
- For the three and six months ended June 30, 2017, royalties as a percentage of sales of 9.8% and 9.4%, respectively, were lower than the comparable periods in the prior year (10.7% and 12.1%, respectively) as a result of the impact of fixed RCDM royalties coupled with higher realized pricing in the current year.

Transportation

- Transportation expense increased in Q2 2017 compared to Q1 2017 and Q2 2016 due to increased vessel-based shipments of crude oil in the current quarter versus the comparable quarters.
- For the six months ended June 30, 2017, transportation expense decreased compared to the same period in 2016 due to fewer vessel-based shipments of crude oil and the strengthening of the Canadian dollar versus the Euro.

Operating

- Operating expense on a per unit basis decreased 8% quarter-over-quarter as the unfavourable foreign exchange impact of the Euro strengthening against the Canadian dollar was offset by higher sales volumes. On a dollar basis, operating expense increased 7% in Q2 2017 compared to Q1 2017 due to the unfavourable foreign exchange impact.
- Operating expense on both a per unit and dollar basis increased in Q2 2017 compared to Q2 2016 largely due to higher electricity costs. For the six months ended June 30, 2017, operating expense on a per unit basis increased year-over-year due to higher electricity costs. On a dollar basis, operating expense decreased due to lower sales volumes.

General and administration

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

Current income taxes

- In France, current income taxes are applied to taxable income, after eligible deductions, at a statutory rate of 34.4%. For 2017, the effective rate on current taxes is expected to be between approximately 6% to 8% of pre-tax fund flows from operations. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Current income taxes in Q2 2017 were lower compared to Q1 2017 as increased sales in Q2 2017 were offset by a lower forecasted full year effective tax rate. Current income taxes for the three and six months ended June 30, 2017 were higher than the comparable periods in the prior year due to increased sales in 2017.

NETHERLANDS BUSINESS UNIT

Overview
- Entered the Netherlands in 2004.
- Second largest onshore gas producer.
- Interests include 24 onshore licenses and two offshore licenses.
- Licenses include more than 800,000 net acres of land, 95% of which is undeveloped.

Operational and financial review

Netherlands business unit ($M except as indicated)	Three Months Ended Jun 30, 2017	Mar 31, 2017	Jun 30, 2016	% change Q2/17 vs. Q1/17	Q2/17 vs. Q2/16	Six Months Ended Jun 30, 2017	Jun 30, 2016	% change 2017 vs. 2016
Production and sales								
Condensate (bbls/d)	**104**	76	96	37%	8%	**90**	105	(14%)
Natural gas (mmcf/d)	**31.58**	39.92	49.18	(21%)	(36%)	**35.73**	51.29	(30%)
Total (boe/d)	**5,368**	6,729	8,293	(20%)	(35%)	**6,044**	8,654	(30%)
Activity								
Capital expenditures	**5,973**	1,712	8,566	249%	(30%)	**7,685**	11,562	(34%)
Acquisitions	**(16)**	16	-			**-**	-	
Financial results								
Sales	**19,126**	26,762	23,973	(29%)	(20%)	**45,888**	51,259	(10%)
Royalties	**(296)**	(419)	(396)	(29%)	(25%)	**(715)**	(856)	(16%)
Operating	**(4,892)**	(4,841)	(4,306)	1%	14%	**(9,733)**	(10,282)	(5%)
General and administration	**(560)**	(596)	(1,223)	(6%)	(54%)	**(1,156)**	(1,996)	(42%)
Current income taxes	**(754)**	(907)	(3,260)	(17%)	(77%)	**(1,661)**	(5,460)	(70%)
Fund flows from operations	**12,624**	19,999	14,788	(37%)	(15%)	**32,623**	32,665	0%
Netbacks ($/boe)								
Sales	**39.16**	44.19	31.77	(11%)	23%	**41.94**	32.55	29%
Royalties	**(0.61)**	(0.69)	(0.52)	(12%)	17%	**(0.65)**	(0.54)	20%
Operating	**(10.01)**	(7.99)	(5.71)	25%	75%	**(8.90)**	(6.53)	36%
General and administration	**(1.14)**	(0.98)	(1.62)	16%	(30%)	**(1.06)**	(1.27)	(17%)
Current income taxes	**(1.54)**	(1.50)	(4.32)	3%	(64%)	**(1.52)**	(3.47)	(56%)
Fund flows from operations netback	**25.86**	33.03	19.60	(22%)	32%	**29.81**	20.74	44%
Realized prices								
Condensate ($/bbl)	**49.59**	58.33	45.05	(15%)	10%	**53.26**	38.10	40%
Natural gas ($/mmbtu)	**6.49**	7.34	5.27	(12%)	23%	**6.96**	5.41	29%
Total ($/boe)	**39.16**	44.19	31.77	(11%)	23%	**41.94**	32.55	29%
Reference prices								
TTF ($/mmbtu)	**6.74**	7.65	5.61	(12%)	20%	**7.21**	5.66	27%
TTF (€/mmbtu)	**4.56**	5.43	3.86	(16%)	18%	**4.99**	3.81	31%

Production
- Q2 2017 production decreased 20% quarter-over-quarter and 35% year-over-year due to the restriction of production related to permitting delays and the scheduled major turnaround project at our Garjip Treatment Centre that occurred in June.
- Production in the Netherlands is currently restricted as we await production permits on certain wells.

Activity review
- Q2 2017 was focused on preparation for our 2017 two (1.0 net) well drilling program, which commenced in early July as well as addressing production permitting delays.
- During the remainder of 2017, we plan to drill two (1.0 net) exploration wells and execute a 220 square kilometre 3D seismic survey.

Sales

- The price of our natural gas in the Netherlands is based on the TTF index.
- Q2 2017 sales per boe decreased versus Q1 2017, consistent with a decrease in the TTF reference price.
- Sales per boe for the three and six months ended June 30, 2017 increased versus the comparable periods in the prior year, consistent with increases in the TTF reference price.

Royalties

- In the Netherlands, we pay overriding royalties on certain wells. As such, fluctuations in royalty expense in the periods presented primarily relates to the amount of production from those wells subject to overriding royalties.

Transportation

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

Operating

- Q2 2017 operating expense on a per boe basis increased versus Q1 2017 due to the impact of relatively consistent total amounts of fixed costs on lower volumes and unfavourable foreign exchange variances. In dollars, operating expense was relatively consistent.
- For the three and six months ended June 30, 2017, operating expense on a per boe basis increased versus the comparable periods in the prior year due to the impact of lower volumes. For the three months ended June 30, 2017, operating expense increased as compared to the same quarter in the prior year due to lower cost recoveries from the Garijp Treatment Centre resulting from a reduction in volumes. For the six months ended June 30, 2017, operating expense decreased as compared to the same period in the prior year due to a favourable foreign exchange impact.

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 abandonment retirement obligations, at a tax rate of 50%. For 2017, the effective rate on current taxes is expected to be between approximately 4% and 6% of pre-tax fund flows from operations. This rate is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Current income taxes in Q2 2017 were lower compared to Q1 2017 due to decreased sales in Q2 2017.
- Current income taxes in the three and six months ended June 30, 2017 were lower compared to the 2016 periods mainly due to a lower forecasted full year effective tax rate in 2017 compared to 2016.

GERMANY BUSINESS UNIT

Overview

- Vermilion entered Germany in February 2014.
- Vermilion successfully integrated the December 2016 acquisition of operated and non-operated interests in five oil and three gas producing fields from Engie E&P Deutschland GmbH ("Engie Acquisition"). Vermilion has assumed operatorship of six of the eight producing fields, representing our first operated producing properties in Germany.
- Hold a 25% interest in a four partner consortium. Associated assets include four gas producing fields spanning 11 production licenses as well as an exploration license in surrounding fields. Total license area comprises 204,000 gross acres, of which 85% is in the exploration license.
- Entered into a farm-in agreement in July 2015 that provides Vermilion with participating interest in 18 onshore exploration licenses in northwest Germany, comprising approximately 850,000 net undeveloped acres of oil and natural gas rights. Vermilion will operate 11 of the 18 licenses during the exploration phase.
- Awarded an exploration license in Lower Saxony in March 2017 comprising 50,000 net acres surrounding the operated oil fields acquired in December 2016.

Operational and financial review

Germany business unit ($M except as indicated)	Three Months Ended Jun 30, 2017	Mar 31, 2017	Jun 30, 2016	% change Q2/17 vs. Q1/17	Q2/17 vs. Q2/16	Six Months Ended Jun 30, 2017	Jun 30, 2016	% change 2017 vs. 2016
Production								
Crude oil (bbls/d)	**1,047**	989	-	6%	100%	**1,018**	-	100%
Natural gas (mmcf/d)	**19.86**	19.39	14.31	2%	39%	**19.63**	15.13	30%
Total (boe/d)	**4,357**	4,220	2,385	3%	83%	**4,289**	2,522	70%
Production mix (% of total)								
Crude oil	**24%**	23%	-			**24%**	-	
Natural gas	**76%**	77%	100%			**76%**	100%	
Activity								
Capital expenditures	**326**	906	592	(64%)	(45%)	**1,232**	1,131	9%
Financial results								
Sales	**16,167**	17,968	6,280	(10%)	157%	**34,135**	13,972	144%
Royalties	**(1,228)**	(1,368)	(964)	(10%)	27%	**(2,596)**	(1,831)	42%
Transportation	**(1,955)**	(1,485)	(1,051)	32%	86%	**(3,440)**	(1,938)	78%
Operating	**(5,753)**	(4,921)	(2,506)	17%	130%	**(10,674)**	(5,099)	109%
General and administration	**(2,099)**	(1,880)	(2,474)	12%	(15%)	**(3,979)**	(4,902)	(19%)
Fund flows from operations	**5,132**	8,314	(715)	(38%)	N/A	**13,446**	202	6,556%
Netbacks ($/boe)								
Sales	**41.96**	47.30	28.94	(11%)	45%	**44.61**	30.44	47%
Royalties	**(3.19)**	(3.60)	(4.44)	(11%)	(28%)	**(3.39)**	(3.99)	(15%)
Transportation	**(5.07)**	(3.91)	(4.84)	30%	5%	**(4.50)**	(4.22)	7%
Operating	**(14.93)**	(12.96)	(11.55)	15%	29%	**(13.95)**	(11.11)	26%
General and administration	**(5.45)**	(4.95)	(11.40)	10%	(52%)	**(5.20)**	(10.68)	(51%)
Fund flows from operations netback	**13.32**	21.88	(3.29)	(39%)	N/A	**17.57**	0.44	3,893%
Realized prices								
Crude oil ($/bbl)	**61.34**	65.62	-	(7%)	100%	**63.54**	-	100%
Natural gas ($/mmbtu)	**6.09**	6.95	4.82	(12%)	26%	**6.51**	5.07	28%
Total ($/boe)	**41.96**	47.30	28.94	(11%)	45%	**44.61**	30.44	47%
Reference prices								
Dated Brent (US $/bbl)	**49.83**	53.78	45.57	(7%)	9%	**51.81**	39.73	30%
Dated Brent ($/bbl)	**67.01**	71.15	58.72	(6%)	14%	**69.10**	52.91	31%
TTF ($/mmbtu)	**6.74**	7.65	5.61	(12%)	20%	**7.21**	5.66	27%
TTF (€/mmbtu)	**4.56**	5.43	3.86	(16%)	18%	**4.99**	3.81	31%

Production

- Q2 2017 production increased 3% from the prior quarter due to well optimization activities and 83% year-over-year due to production additions from the Engie Acquisition that closed December 2016.

Activity review

- Q2 2017 activity focused on the identification of optimization opportunities on the acquired assets.
- In 2017, we plan to continue our ongoing analysis of the geologic data associated with the farm-in assets and to continue integration activities associated with the asset acquisition. We will also continue permitting and pre-drill activities associated with our first operated well in Germany, Burgmoor Z5 (25% working interest) in the Dümmersee-Uchte area, which we plan to drill in 2018 or 2019.

Sales

- The price of our natural gas in Germany is based on the TTF index. Crude oil in Germany is priced with reference to Dated Brent.
- Q2 2017 sales per boe decreased versus Q1 2017, consistent with decreases in the Dated Brent and TTF reference prices.
- Sales per boe for the three and six months ended June 30, 2017 increased as a result of stronger TTF prices and the addition of crude oil production in 2017.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Q2 2017 royalties as a percentage of sales remained consistent with Q1 2017 at 7.6%.
- Royalties as a percentage of sales for the three and six months ended June 30, 2017 of 7.6% decreased from 15.4% and 13.1% in the comparable periods in 2016 due to lower royalties associated with the crude oil properties acquired in December 2016.

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.
- Q2 2017 transportation expense increased versus Q1 2017 on both a per unit and dollar basis due to a prior period amendment relating to 2016 recorded in the current quarter.
- For the three and six months ended June 30, 2017, transportation expense on a per boe basis increased 5% and 7% versus the comparable periods in the prior year due to the prior period amendment as well as the aforementioned acquisition.

Operating

- Operating expense increased in Q2 2017 versus Q1 2017 on both a per unit and dollar basis due to higher maintenance activity as compared to Q1 2017 and unfavourable foreign exchange variances.
- For the three and six months ended June 30, 2017, operating expense on both a per unit and dollar basis increased versus the comparable periods in the prior year due to the aforementioned acquisition.

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.
- On a per unit basis, general and administration costs have improved compared to 2016 as a result of our growing production base in Germany.

Current income taxes

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

IRELAND BUSINESS UNIT

Overview

- Vermilion entered Ireland in 2009.
- Initial investment was an 18.5% non-operating interest in the offshore Corrib gas field located approximately 83 km off the northwest coast of Ireland.
- On July 12, 2017 Vermilion and Canada Pension Plan Investment Board ("CPPIB") announced a strategic partnership that is expected to result in Vermilion increasing ownership in Corrib to 20% and taking over operatorship upon close of the acquisition.
- Project comprises six offshore wells, offshore and onshore sales and transportation pipeline segments as well as a natural gas processing facility.
- Production volumes reached full plant capacity of approximately 65 mmcf/d (10,900 boe/d), net to Vermilion, at the end of Q2 2016.

Operational and financial review

	Three Months Ended			% change		Six Months Ended		% change
Ireland business unit ($M except as indicated)	**Jun 30, 2017**	**Mar 31, 2017**	**Jun 30, 2016**	**Q2/17 vs. Q1/17**	**Q2/17 vs. Q2/16**	**Jun 30, 2017**	**Jun 30, 2016**	**2017 vs. 2016**
Production and sales								
Natural gas (mmcf/d)	**63.81**	64.82	47.26	(2%)	35%	**64.31**	40.58	58%
Total (boe/d)	**10,634**	10,803	7,877	(2%)	35%	**10,718**	6,763	58%
Activity								
Capital expenditures	**(73)**	(804)	2,172	(91%)	N/A	**(877)**	5,248	N/A
Financial results								
Sales	**36,671**	44,648	23,360	(18%)	57%	**81,319**	40,364	101%
Transportation	**(1,258)**	(1,199)	(1,574)	5%	(20%)	**(2,457)**	(3,213)	(24%)
Operating	**(4,903)**	(3,999)	(5,177)	23%	(5%)	**(8,902)**	(8,803)	1%
General and administration	**(695)**	(438)	(1,106)	59%	(37%)	**(1,133)**	(2,294)	(51%)
Fund flows from operations	**29,815**	39,012	15,503	(24%)	92%	**68,827**	26,054	164%
Netbacks ($/boe)								
Sales	**37.90**	45.92	32.59	(17%)	16%	**41.92**	32.79	28%
Transportation	**(1.30)**	(1.23)	(2.20)	6%	(41%)	**(1.27)**	(2.61)	(51%)
Operating	**(5.07)**	(4.11)	(7.22)	23%	(30%)	**(4.59)**	(7.15)	(36%)
General and administration	**(0.72)**	(0.45)	(1.54)	60%	(53%)	**(0.58)**	(1.86)	(69%)
Fund flows from operations netback	**30.81**	40.13	21.63	(23%)	42%	**35.48**	21.17	68%
Reference prices								
NBP ($/mmbtu)	**6.52**	7.96	5.78	(18%)	13%	**7.26**	5.88	23%
NBP (€/mmbtu)	**4.41**	5.64	3.97	(22%)	11%	**5.02**	3.96	27%

Production

- Natural gas began to flow from our Corrib gas project on December 30, 2015 and production volumes reached full plant capacity of approximately 65 mmcf/d (10,900 boe/d), net to Vermilion at the end of Q2 2016.
- Q2 2017 production was in-line with prior quarter production and increased 35% year-over-year as Q2 2016 production volumes were restricted during the commissioning period that occurred in the first half of 2016.
- Production results continued to benefit from better-than-expected well deliverability and minimal downtime.

Activity review

- On July 12, 2017 Vermilion and CPPIB announced a strategic partnership in Corrib, whereby CPPIB will acquire Shell Exploration Company B.V.'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 850 boe/d (100% gas) based on 2017 production expectations for Corrib. The acquisition has an effective date of January 1, 2017 and is anticipated to close in the first half of 2018.
- There is limited capital activity planned for 2017.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Q2 2017 sales per boe decreased relative to Q1 2017, consistent with decreases in the NBP reference price.
- Sales per boe for three and six months ended June 30, 2017 increased relative to the comparable periods in the prior year, 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.
- Q2 2017 transportation expense was consistent with Q1 2017 in Euros, and the increase in Canadian dollars was solely due to the impact of the strengthening Euro versus the Canadian dollar.
- Transportation expense for the three and six months ended June 30, 2017 decreased relative to the comparable periods in the prior year due a decrease in the current year ship-or-pay obligation.

Operating

- Q2 2017 operating expense on a per unit and dollar basis increased as compared to Q1 2017 due to general operations and onshore maintenance activities, as well as unfavourable foreign exchange variances.
- Operating expense on a per unit basis decreased for the three and six months ended June 30, 2017 versus the comparable periods in 2016 as a result of increased production. Operating expense on a dollar basis was relatively consistent with the comparable periods.

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 Ireland, 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

	Three Months Ended			% change		Six Months Ended		% change
Australia business unit ($M except as indicated)	**Jun 30, 2017**	**Mar 31, 2017**	**Jun 30, 2016**	**Q2/17 vs. Q1/17**	**Q2/17 vs. Q2/16**	**Jun 30, 2017**	**Jun 30, 2016**	**2017 vs. 2016**
Production								
Crude oil (bbls/d)	**6,054**	6,581	6,083	(8%)	-	**6,316**	6,132	3%
Sales								
Crude oil (bbls/d)	**7,400**	5,041	6,021	47%	23%	**6,227**	5,345	17%
Inventory (mbbls)								
Opening crude oil inventory	**253**	115	213	120%	19%	**115**	75	53%
Crude oil production	**550**	592	554	(7%)	(1%)	**1,143**	1,116	2%
Crude oil sales	**(672)**	(454)	(549)	48%	22%	**(1,127)**	(973)	16%
Closing crude oil inventory	**131**	253	218			**131**	218	
Activity								
Capital expenditures	**9,158**	3,438	39,939	166%	(77%)	**12,596**	47,766	(74%)
Gross wells drilled	**-**	-	2.00			**-**	2.00	
Net wells drilled	**-**	-	2.00			**-**	2.00	
Financial results								
Sales	**48,061**	34,987	33,713	37%	43%	**83,048**	53,648	55%
Operating	**(15,639)**	(10,036)	(12,100)	56%	29%	**(25,675)**	(19,591)	31%
General and administration	**(896)**	(2,430)	(1,788)	(63%)	(50%)	**(3,326)**	(3,113)	7%
Current income taxes	**(7,660)**	(6,830)	(1,270)	12%	503%	**(14,490)**	(2,175)	566%
Fund flows from operations	**23,866**	15,691	18,555	52%	29%	**39,557**	28,769	37%
Netbacks ($/boe)								
Sales	**71.37**	77.11	61.53	(7%)	16%	**73.68**	55.15	34%
Operating	**(23.22)**	(22.12)	(22.08)	5%	5%	**(22.78)**	(20.14)	13%
General and administration	**(1.33)**	(5.35)	(3.26)	(75%)	(59%)	**(2.95)**	(3.20)	(8%)
PRRT	**(9.61)**	(11.98)	(0.26)	(20%)	3,596%	**(10.56)**	(0.28)	3,671%
Corporate income taxes	**(1.77)**	(3.08)	(2.05)	(43%)	(14%)	**(2.30)**	(1.96)	17%
Fund flows from operations netback	**35.44**	34.58	33.88	2%	5%	**35.09**	29.57	19%
Reference prices								
Dated Brent (US $/bbl)	**49.83**	53.78	45.57	(7%)	9%	**51.81**	39.73	30%
Dated Brent ($/bbl)	**67.01**	71.15	58.72	(6%)	14%	**69.10**	52.91	31%

Production

- Q2 2017 production decreased 8% quarter-over-quarter and was consistent with Q2 2016.
- 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 production levels of between 6,000 and 8,000 bbls/d.

Activity review

- Q2 2017 efforts were largely focused on facilities enhancement, including work relating to platform life extension.
- Following our successful 2015 and 2016 drilling campaigns, we do not expect to drill any additional wells in Australia until 2019.
- 2017 activity will be focused on adding value through asset optimization and targeted proactive maintenance.

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Q2 2017 sales per boe decreased versus Q1 2017, consistent with lower Dated Brent prices. This decrease in price was more than offset by higher sales volumes due to a 122,000 bbl inventory draw during Q2 as compared to a 138,000 bbl build in Q1.
- Sales per boe for the three and six months ended June 30, 2017 increased versus the comparable periods in the prior year, consistent with higher Dated Brent prices. In both periods, the increase in price was coupled with higher sales volumes, resulting in a greater increase in sales.

Royalties and transportation

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

Operating

- Operating expense on a per unit basis increased versus all comparable periods due to the timing of maintenance work. On a dollar basis, operating expense increased due to higher sales volumes.

General and administration

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

Current income taxes

- In 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.
- For 2017, the effective tax rate for current income taxes is expected to be between approximately 25% and 27% 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.
- Current income taxes in the three and six months ended June 30, 2017 were higher versus the comparable periods due to increased sales.

UNITED STATES BUSINESS UNIT

Overview

- Entered the United States in September 2014.
- Interests include approximately 94,600 net acres of land (97% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Tight oil development targeting the Turner Sand at a depth of approximately 1,500 metres.

Operational and financial review

	Three Months Ended			% change		Six Months Ended		% change
United States business unit ($M except as indicated)	**Jun 30, 2017**	**Mar 31, 2017**	**Jun 30, 2016**	**Q2/17 vs. Q1/17**	**Q2/17 vs. Q2/16**	**Jun 30, 2017**	**Jun 30, 2016**	**2017 vs. 2016**
Production and sales								
Crude oil (bbls/d)	**747**	365	458	105%	63%	**557**	413	35%
NGLs (bbls/d)	**76**	24	26	217%	192%	**50**	33	52%
Natural gas (mmcf/d)	**0.44**	0.20	0.20	120%	119%	**0.32**	0.23	40%
Total (boe/d)	**896**	422	518	112%	73%	**660**	484	36%
Activity								
Capital expenditures	**5,155**	11,539	1,636	(55%)	215%	**16,694**	6,737	148%
Acquisitions	**49**	2,013	5,432			**2,062**	5,547	
Gross wells drilled	**-**	3.00	-			**3.00**	-	
Net wells drilled	**-**	3.00	-			**3.00**	-	
Financial results								
Sales	**4,108**	2,126	2,207	93%	86%	**6,234**	3,440	81%
Royalties	**(1,160)**	(599)	(661)	94%	75%	**(1,759)**	(1,031)	71%
Operating	**(387)**	(285)	(302)	36%	28%	**(672)**	(581)	16%
General and administration	**(1,127)**	(1,005)	(697)	12%	62%	**(2,132)**	(1,829)	17%
Fund flows from operations	**1,434**	237	547	505%	162%	**1,671**	(1)	N/A
Netbacks ($/boe)								
Sales	**50.37**	55.99	46.80	(10%)	8%	**52.15**	39.03	34%
Royalties	**(14.21)**	(15.79)	(14.02)	(10%)	1%	**(14.71)**	(11.70)	26%
Operating	**(4.74)**	(7.51)	(6.39)	(37%)	(26%)	**(5.62)**	(6.59)	(15%)
General and administration	**(13.82)**	(26.46)	(14.77)	(48%)	(6%)	**(17.83)**	(20.76)	(14%)
Fund flows from operations netback	**17.60**	6.23	11.62	183%	51%	**13.99**	(0.02)	N/A
Realized prices								
Crude oil ($/bbl)	**58.05**	61.68	52.56	(6%)	10%	**59.23**	45.09	31%
NGLs ($/bbl)	**14.70**	25.67	3.25	(43%)	352%	**17.32**	4.18	314%
Natural gas ($/mmbtu)	**1.55**	2.48	0.37	(38%)	319%	**1.84**	0.54	241%
Total ($/boe)	**50.37**	55.99	46.80	(10%)	8%	**52.15**	39.03	34%
Reference prices								
WTI (US $/bbl)	**48.28**	51.92	45.59	(7%)	6%	**50.10**	39.52	27%
WTI ($/bbl)	**64.92**	68.69	58.75	(5%)	11%	**66.82**	52.63	27%
Henry Hub (US $/mmbtu)	**3.18**	3.31	1.95	(4%)	63%	**3.25**	2.02	61%
Henry Hub ($/mmbtu)	**4.28**	4.38	2.52	(2%)	70%	**4.33**	2.69	61%

Production

- Q2 2017 production increased 112% from the prior quarter and 73% year-over-year as a result of production additions from our three (3.0 net) well drilling program.

Activity

- In Q2 2017, we brought on production three (3.0 net) wells targeting the light oil bearing Turner Sand in the Powder River Basin. The wells were completed late in the first quarter and into the second quarter with frac stages ranging from 31 to 40 stages per well.
- In Q4 2016, we completed the Seedy Draw East Federal well. The nearly 1,400 metre horizontal lateral was stimulated with 32 frac stages, but due to a screen-out during treatment, only 23 stages were completed. We initiated the clean out of sand from this well during the first quarter resulting in an additional 18 stages being completed. The well was returned to production in Q2 2017.

Sales

- The price of crude oil in the United States is directly linked to WTI, but is also subject to market conditions in the United States.
- Q2 2017 sales per boe decreased versus Q1 2017 consistent with lower crude oil prices.
- For the three and six months ended June 30, 2017, sales per boe increased relative to the comparable periods in the prior year, consistent with stronger crude oil pricing.

Royalties

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax.
- Royalties (including severance and ad valorem taxes) as a percentage of sales for Q2 2017 of 28.2% was consistent with Q1 2017.
- For the three and six months ended June 30, 2017, royalties as a percentage of sales decreased to 28.2% from 30.0% in the comparable periods in the prior year. This decrease is a result of our purchase of overriding royalty interests (ranging from 0.83% to 5%) for US$1.5 million, effective January 1, 2017. On a go-forward basis, we expect royalties as a percentage of sales to remain at approximately 28%.

Operating

- Operating expense on a per unit basis decreased across all periods presented due to the impact of fixed costs on higher volumes. In dollars, the increase in operating expense across all periods presented was consistent with higher production.

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 the United States, we do not expect to incur current income taxes in the United States Business Unit for the foreseeable future.

CORPORATE

Overview

- Our Corporate segment includes costs related to our global hedging program, financing expenses, and general and administration expenses that are primarily incurred in Canada and are not directly related to the operations of our business units. Expenditures relating to our activities in Central and Eastern Europe are also included in the Corporate segment.

Financial review

CORPORATE ($M)	Three Months Ended Jun 30, 2017	Three Months Ended Mar 31, 2017	Three Months Ended Jun 30, 2016	Six Months Ended Jun 30, 2017	Six Months Ended Jun 30, 2016
Activity					
Capital expenditures	**1,055**	725	418	**1,780**	418
Acquisitions	**25**	15	2,322	**40**	2,322
Financial Results					
General and administration (expense) recovery	**(950)**	(2,034)	834	**(2,984)**	1,255
Current income taxes	**(271)**	(194)	(257)	**(465)**	(406)
Interest expense	**(15,508)**	(14,695)	(13,647)	**(30,203)**	(28,397)
Realized gain (loss) on derivatives	**5,342**	(1,851)	21,501	**3,491**	49,924
Realized foreign exchange gain	**981**	2,546	1,329	**3,527**	677
Realized other income	**252**	42	62	**294**	167
Fund flows from operations	**(10,154)**	(16,186)	9,822	**(26,340)**	23,220

General and administration

- Fluctuations in general and administration costs for the three and six months ended June 30, 2017 versus all comparable periods were due to allocations to the various business unit segments.

Current income taxes

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

Interest expense

- The increase in interest expense for the three and six months ended June 30, 2017 versus all comparable periods was primarily due to the recognition of a full quarter of interest on the senior unsecured notes issued in Q1 2017, which bear interest at a higher rate than the revolving credit facility.

Realized gain or loss on derivatives

- The realized gain on derivatives for the three and six months ended June 30, 2017 related primarily to amounts received on our crude oil hedges. Additionally, the realized gain on derivatives for the three months ended June 30, 2017 also related to amounts received on our European natural gas hedges.
- A listing of derivative positions as at June 30, 2017 is included in "Supplemental Table 2" of this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Three Months Ended							
($M except per share)	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016	Dec 31, 2015	Sep 30, 2015
Petroleum and natural gas sales	**271,391**	261,601	259,891	232,660	212,855	177,385	234,319	245,051
Net earnings (loss)	**48,264**	44,540	(4,032)	(14,475)	(55,696)	(85,848)	(142,080)	(83,310)
Net earnings (loss) per share								
Basic	**0.40**	0.38	(0.03)	(0.12)	(0.48)	(0.76)	(1.28)	(0.76)
Diluted	**0.39**	0.37	(0.03)	(0.12)	(0.48)	(0.76)	(1.28)	(0.76)

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

	Three Months Ended			Six Months Ended	
	Jun 30, 2017	Mar 31, 2017	Jun 30, 2016	Jun 30, 2017	Jun 30, 2016
Fund flows from operations	**147,123**	143,434	126,568	**290,557**	220,235
Equity based compensation	**(13,896)**	(18,738)	(13,267)	**(32,634)**	(34,104)
Unrealized gain (loss) on derivative instruments	**23,283**	79,865	(72,436)	**103,148**	(63,382)
Unrealized foreign exchange gain (loss)	**38,616**	(4,518)	(2,804)	**34,098**	(1,234)
Unrealized other expense	**(210)**	(30)	(20)	**(240)**	(107)
Accretion	**(6,748)**	(6,382)	(6,025)	**(13,130)**	(12,134)
Depletion and depreciation	**(126,269)**	(115,409)	(131,793)	**(241,678)**	(257,591)
Deferred taxes	**(13,635)**	(33,682)	44,081	**(47,317)**	21,535
Impairment	**-**	-	-	**-**	(14,762)
Net earnings (loss)	**48,264**	44,540	(55,696)	**92,804**	(141,544)

The 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 amounts 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 in Q2 2017 decreased as compared to Q1 2017 due to the absence of the settlement of the employee bonus plan with equity that occurred in Q1 2017. For the six months ended June 30, 2017, the decrease in equity based compensation is primarily due to a reduction in the value of VIP outstanding.

Unrealized gain or loss on derivative instruments

Unrealized gain or loss on derivative instruments arise as a result of changes in forecasted future commodity prices. 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 forecasted future commodity prices decline and vice-versa.

For the six months ended June 30, 2017, we recognized an unrealized gain on derivative instruments of $103.1 million. This unrealized gain resulted from lower forward prices for crude oil and European natural gas as at June 30, 2017. As at June 30, 2017, we have a net derivative asset position of $33.5 million as compared to a net derivative liability position of $69.7 million as at December 31, 2016.

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, primarily denominated in the US dollar and Euro.

Unrealized foreign exchange gains and losses result from translating these monetary assets and liabilities from their underlying currency to the functional currency of Vermilion and its subsidiaries. Unrealized foreign exchange primarily results from the translation of Euro denominated financial assets and US dollar denominated financial liabilities. 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).

As at June 30, 2017, the Canadian dollar weakened against the Euro but strengthened against the US dollar for both the three and six month periods, resulting in unrealized foreign exchange gains in both periods.

Accretion
Accretion expense is recognized to update the present value of the asset retirement obligation balance. Accretion expense was relatively consistent with all comparative periods.

Depletion and depreciation
Depletion and depreciation expense is recognized to allocate the capitalized cost of extracting natural resources and the cost of material assets over the useful life of the respective assets. 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 rates. Fluctuations in depletion and depreciation rates are primarily the result of changes in reserves and future development costs.

Depletion and depreciation on a per boe basis for Q2 2017 of \$20.30 was relatively consistent with \$20.71 in Q1 2017. For the three and six months ended June 30, 2017, depletion and depreciation on a per boe basis of \$20.30 and \$20.49, respectively, were lower than \$22.80 and \$22.23 in the respective comparable periods in 2016 due to reduced depletion and depreciation rates as a result of increased reserves coupled with lower estimated future development costs.

Deferred tax
Deferred tax recovery arises primarily as a result of changes in the accounting basis and tax basis for capital assets and asset retirement obligations and changes in available tax losses.

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 and typically strive to maintain an internally targeted ratio of approximately 1.0 to 1.5 in a normalized commodity price environment. Where prices trend higher, we may target a lower ratio and conversely, in a lower commodity price environment, an acceptable ratio may be higher. At times, we will use our balance sheet to finance acquisitions and, in these situations, we are prepared to accept a higher ratio in the short term but will implement a strategy to reduce the ratio to acceptable levels within a reasonable period of time, usually considered to be no more than 12 to 24 months. This plan could potentially include an increase in hedging activities, a reduction in capital expenditures, an issuance of equity or the utilization of excess fund flows from operations to reduce outstanding indebtedness.

In the current low commodity price environment, Vermilion's net debt to fund flows from operations ratio is expected to be higher than the internally targeted ratio. During this period, Vermilion will remain focused on maintaining a strong balance sheet by aligning capital expenditures and net dividends within forecasted fund flows from operations, which is continually monitored for revised forward price estimates, as well as by hedging additional volumes to maintain a diversified commodity portfolio.

The balances recognized on our balance sheet are as follows:

	As at	
(\$M)	**Jun 30, 2017**	**Dec 31, 2016**
Revolving credit facility	**879,169**	1,362,192
Senior unsecured notes	**383,066**	-
Long-term debt	**1,262,235**	1,362,192

Revolving Credit Facility

As at June 30, 2017, Vermilion had in place a bank revolving credit facility maturing May 31, 2021 with the following terms:

	As at	
($M)	Jun 30, 2017	Dec 31, 2016
Total facility amount	**1,400,000**	2,000,000
Amount drawn	**(879,169)**	(1,362,192)
Letters of credit outstanding	**(4,500)**	(20,100)
Unutilized capacity	**516,331**	617,708

In April of 2017, we negotiated an extension of our revolving credit facility with our syndicate of lenders from May 31, 2019 to May 31, 2021. Further, as a result of projected liquidity requirements and the proceeds from our senior unsecured notes issuance, we elected to reduce the total facility amount from $2.0 billion to $1.4 billion.

As at June 30, 2017, the revolving credit facility was subject to the following covenants:

		As at	
Financial covenant	Limit	June 30, 2017	Dec 31, 2016
Consolidated total debt to consolidated EBITDA	4.0	**1.91**	2.36
Consolidated total senior debt to consolidated EBITDA	3.5	**1.30**	2.32
Consolidated total senior debt to total capitalization	55%	**30%**	46%

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" and "Finance lease obligation" 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.
- 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, to be 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 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	102.819%
2022	101.406%
2023 and thereafter	100.000%

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

	As at	
($M)	Jun 30, 2017	Dec 31, 2016
Long-term debt	**1,262,235**	1,362,192
Current liabilities	**247,768**	290,862
Current assets	**(195,237)**	(225,906)
Net debt	**1,314,766**	1,427,148
Ratio of net debt to annualized fund flows from operations	**2.3**	2.8

As at June 30, 2017, long term debt decreased to $1.26 billion (December 31, 2016 - $1.36 billion) as fund flows from operations generated in excess of expenditures was used to reduce debt. This decrease in long-term debt, in addition to an increase in net current derivative assets, decreased net debt from $1.43 billion at December 31, 2016 to $1.31 billion at June 30, 2017. The decrease in net debt coupled with an increase in fund flows from operations resulted in a decrease in the ratio of net debt to annualized fund flows from operations from 2.8 to 2.3.

Shareholders' capital
During the six months ended June 30, 2017, we maintained monthly dividends at $0.215 per share and declared $154.5 million of dividends.

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 31, 2013	$0.200
January 2014 to Present	$0.215

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.

We commenced proration of the Premium Dividend Component in 2016 and continued proration throughout 2017. We have discontinued the Premium Dividend™ Component of our Dividend Reinvestment Plan beginning with the July 2017 dividend payment.

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 as at December 31, 2016	118,263	2,452,722
Shares issued for the Dividend Reinvestment Plan	1,325	64,747
Vesting of equity based awards	1,059	69,675
Share-settled dividends on vested equity based awards	170	8,473
Shares issued for equity based compensation	130	6,397
Balance as at June 30, 2017	120,947	2,602,014

As at June 30, 2017, there were approximately 1.7 million VIP awards outstanding. As at July 25, 2017, there were approximately 121.2 million common shares issued and outstanding.

ASSET RETIREMENT OBLIGATIONS

As at June 30, 2017, asset retirement obligations were $550.4 million compared to $525.0 million as at December 31, 2016.

The increase in asset retirement obligations is largely attributable to accretion and the impact of foreign exchange fluctuations.

OFF BALANCE SHEET ARRANGEMENTS

We have certain lease agreements that are entered into in the normal course of operations, including operating leases for which no asset or liability value has been assigned to the consolidated balance sheet as at June 30, 2017.

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 detailed discussion of these risks, please see Vermilion's Annual Report for the year ended December 31, 2016.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of any possible contingencies. These estimates and assumptions are developed based on the best available information which management believed to be reasonable at the time such estimates and assumptions were made. As such, these assumptions are uncertain at the time estimates are made and could change, resulting in a material impact on Vermilion's consolidated financial statements. Estimates are reviewed by management on an ongoing basis and as a result may change from period to period due to the availability of new information or changes in circumstances. Additionally, as a result of the unique circumstances of each jurisdiction that Vermilion operates in, the critical accounting estimates may affect one or more jurisdictions. There have been no material changes to our critical accounting estimates used in applying accounting policies for the six months ended June 30, 2017. 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, 2016, 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 that occurred during the period covered by this MD&A that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

The following IFRS have been issued by the IASB but are not yet effective:

- IFRS 9 "Financial Instruments" will be adopted January 1, 2018. IFRS 9 includes changes to the classification and measurement of financial instruments and general hedge accounting.
- IFRS 15 "Revenue from Contracts with Customers" will be adopted January 1, 2018. IFRS 15 specifies recognition and measurement requirements for contracts with customers.
- IFRS 16 "Leases" will be adopted January 1, 2019. IFRS 16 requires lessees to recognize a lease obligation and right-of-use asset for the majority of leases.

On the adoption of IFRS 9, Vermilion does not currently anticipate changes to the measured amount of financial instruments and correspondingly does not currently anticipate material changes to net earnings.

In the adoption of IFRS 15, Vermilion has in place a transition team that has been performing a detailed review of the Company's standard contracts with customers in accordance with the issued IFRS to determine the impact, if any, the adoption of IFRS 15 will have on its financial statements. Vermilion continues to assess this new standard and review its impacts.

The impact of the adoption of IFRS 16 is currently being evaluated.

Supplemental Table 1: Netbacks

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

	Three Months Ended June 30, 2017			Six Months Ended June 30, 2017			Three Months Ended June 30, 2016	Six Months Ended June 30, 2016
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	50.50	2.83	**32.18**	52.37	2.91	**32.85**	25.39	23.18
Royalties	(6.82)	(0.09)	**(3.39)**	(6.98)	(0.15)	**(3.57)**	(1.55)	(1.82)
Transportation	(1.96)	(0.19)	**(1.52)**	(2.21)	(0.20)	**(1.66)**	(1.55)	(1.56)
Operating	(6.92)	(1.31)	**(7.44)**	(7.43)	(1.24)	**(7.43)**	(6.77)	(7.44)
Operating netback	34.80	1.24	**19.83**	35.75	1.32	**20.19**	15.52	12.36
General and administration			**(1.20)**			**(1.00)**	(1.77)	(1.33)
Fund flows from operations netback			**18.63**			**19.19**	13.75	11.03
France								
Sales	62.09	-	**62.09**	64.75	1.52	**64.75**	57.82	50.32
Royalties	(6.10)	-	**(6.10)**	(6.08)	(0.41)	**(6.08)**	(6.16)	(6.11)
Transportation	(3.60)	-	**(3.60)**	(3.53)	-	**(3.53)**	(3.26)	(3.30)
Operating	(11.86)	-	**(11.86)**	(12.36)	(1.21)	**(12.36)**	(10.57)	(11.73)
Operating netback	40.53	-	**40.53**	42.78	(0.10)	**42.78**	37.83	29.18
General and administration			**(3.62)**			**(3.56)**	(4.44)	(4.32)
Current income taxes			**(1.79)**			**(3.58)**	(0.86)	(0.44)
Fund flows from operations netback			**35.12**			**35.64**	32.53	24.42
Netherlands								
Sales	49.59	6.49	**39.16**	53.26	6.96	**41.94**	31.77	32.55
Royalties	-	(0.10)	**(0.61)**	-	(0.11)	**(0.65)**	(0.52)	(0.54)
Operating	-	(1.70)	**(10.01)**	-	(1.51)	**(8.90)**	(5.71)	(6.53)
Operating netback	49.59	4.69	**28.54**	53.26	5.34	**32.39**	25.54	25.48
General and administration			**(1.14)**			**(1.06)**	(1.62)	(1.27)
Current income taxes			**(1.54)**			**(1.52)**	(4.32)	(3.47)
Fund flows from operations netback			**25.86**			**29.81**	19.60	20.74
Germany								
Sales	61.34	6.09	**41.96**	63.54	6.51	**44.61**	28.94	30.44
Royalties	1.25	(0.74)	**(3.19)**	(1.28)	(0.67)	**(3.39)**	(4.44)	(3.99)
Transportation	(9.22)	(0.65)	**(5.07)**	(8.65)	(0.55)	**(4.50)**	(4.84)	(4.22)
Operating	(20.99)	(2.21)	**(14.93)**	(18.70)	(2.09)	**(13.95)**	(11.55)	(11.11)
Operating netback	32.38	2.49	**18.77**	34.91	3.20	**22.77**	8.11	11.12
General and administration			**(5.45)**			**(5.20)**	(11.40)	(10.68)
Fund flows from operations netback			**13.32**			**17.57**	(3.29)	0.44
Ireland								
Sales	-	6.32	**37.90**	-	6.99	**41.92**	32.59	32.79
Transportation	-	(0.22)	**(1.30)**	-	(0.21)	**(1.27)**	(2.20)	(2.61)
Operating	-	(0.84)	**(5.07)**	-	(0.76)	**(4.59)**	(7.22)	(7.15)
Operating netback	-	5.26	**31.53**	-	6.02	**36.06**	23.17	23.03
General and administration			**(0.72)**			**(0.58)**	(1.54)	(1.86)
Fund flows from operations netback			**30.81**			**35.48**	21.63	21.17
Australia								
Sales	71.37	-	**71.37**	73.68	-	**73.68**	61.53	55.15
Operating	(23.22)	-	**(23.22)**	(22.78)	-	**(22.78)**	(22.08)	(20.14)
PRRT (1)	(9.61)	-	**(9.61)**	(10.56)	-	**(10.56)**	(0.26)	(0.28)
Operating netback	38.54	-	**38.54**	40.34	-	**40.34**	39.19	34.73
General and administration			**(1.33)**			**(2.95)**	(3.26)	(3.20)
Corporate income taxes			**(1.77)**			**(2.30)**	(2.05)	(1.96)
Fund flows from operations netback			**35.44**			**35.09**	33.88	29.57

	Three Months Ended June 30, 2017			Six Months Ended June 30, 2017			Three Months Ended June 30, 2016	Six Months Ended June 30, 2016
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
United States								
Sales	54.05	1.55	**50.37**	55.77	1.84	**52.15**	46.80	39.03
Royalties	(15.13)	(0.66)	**(14.21)**	(15.60)	(0.78)	**(14.71)**	(14.02)	(11.70)
Operating	(5.16)	-	**(4.74)**	(6.11)	-	**(5.62)**	(6.39)	(6.59)
Operating netback	33.76	0.89	**31.42**	34.06	1.06	**31.82**	26.39	20.74
General and administration			**(13.82)**			**(17.83)**	(14.77)	(20.76)
Fund flows from operations netback			**17.60**			**13.99**	11.62	(0.02)
Total Company								
Sales	59.40	4.75	**43.63**	61.50	5.18	**45.19**	36.83	33.67
Realized hedging gain	0.76	0.16	**0.86**	0.60	0.01	**0.30**	3.72	4.31
Royalties	(5.03)	(0.13)	**(2.85)**	(5.20)	(0.15)	**(2.88)**	(2.14)	(2.27)
Transportation	(2.22)	(0.21)	**(1.74)**	(2.37)	(0.20)	**(1.75)**	(1.71)	(1.75)
Operating	(12.51)	(1.31)	**(10.14)**	(12.62)	(1.22)	**(9.77)**	(9.02)	(9.30)
PRRT [(1)]	(2.12)	-	**(1.04)**	(2.18)	-	**(1.01)**	(0.02)	(0.02)
Operating netback	38.28	3.26	**28.72**	39.73	3.62	**30.08**	27.66	24.64
General and administration			**(2.12)**			**(2.23)**	(2.68)	(2.51)
Interest expense			**(2.49)**			**(2.56)**	(2.36)	(2.45)
Realized foreign exchange gain			**0.16**			**0.30**	0.23	0.06
Other income			**0.04**			**0.02**	0.01	0.01
Corporate income taxes [(1)]			**(0.65)**			**(0.98)**	(0.96)	(0.75)
Fund flows from operations netback			**23.66**			**24.63**	21.90	19.00

(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 June 30, 2017:

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 (mmbtu/d) [2]
Dated Brent												
3-Way Collar	Jan 2017 - Dec 2017		USD	2,500	51.00	2,500	60.50	2,500	41.50	-	-	-
3-Way Collar	Jul 2017 - Jun 2018		USD	2,000	55.00	2,000	64.06	2,000	45.00	-	-	-
3-Way Collar	Jul 2017 - Dec 2018		USD	1,000	48.70	1,000	55.00	1,000	42.50	-	-	-
Collar	Jan 2018 - Dec 2018		USD	500	50.00	500	57.50	-	-	-	-	-
Put Spread	Apr 2017 - Dec 2017		USD	600	56.00	-	-	600	46.25	-	-	-
Put Spread	May 2017 - Dec 2017		USD	680	55.00	-	-	680	46.00	-	-	-
Put Spread	Jul 2017 - Dec 2017		USD	500	55.00	-	-	500	47.50	-	-	-
Swaption	Jan 2018 - Dec 2018	Sep 29, 2017	USD	-	-	-	-	-	-	1,000	55.00	-
Swaption	Jan 2018 - Dec 2018	Dec 29, 2017	USD	-	-	-	-	-	-	500	49.00	-
WTI												
3-Way Collar	Jan 2017 - Dec 2017		CAD	1,500	70.00	1,500	75.00	1,500	55.00	-	-	-
3-Way Collar	Jul 2017 - Dec 2017		USD	3,000	54.33	3,000	65.58	3,000	45.00	-	-	-
Put	Jul 2017 - Sep 2017		USD	3,000	42.50	-	-	-	-	-	-	-

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												
Collar	Nov 2016 - Oct 2017		CAD	7,109	2.18	9,478	2.86	-	-	-	-	-
Collar	Nov 2016 - Dec 2017		CAD	9,478	2.33	9,478	3.02	-	-	-	-	-
Collar	Jan 2017 - Dec 2017		CAD	4,739	2.37	4,739	3.25	-	-	-	-	-
Collar	Nov 2017 - Dec 2017		CAD	4,739	2.95	4,739	3.38	-	-	-	-	-
Swap	Nov 2016 - Dec 2017		CAD	-	-	-	-	-	-	2,370	2.99	-
Swap	Jan 2017 - Dec 2017		CAD	-	-	-	-	-	-	7,109	2.94	-
Swap	Apr 2017 - Oct 2017		CAD	-	-	-	-	-	-	7,109	3.01	-
Swap	Jun 2017 - Oct 2017		CAD	-	-	-	-	-	-	4,739	2.91	-
Swap	Jul 2017 - Sep 2017		CAD	-	-	-	-	-	-	4,739	3.17	-
Swap	Nov 2017 - Dec 2017		CAD	-	-	-	-	-	-	7,109	3.35	-
Swap	Jan 2018 - Dec 2018		CAD	-	-	-	-	-	-	9,478	2.80	-
AECO Basis (AECO less NYMEX HH)												
Swap	Jan 2017 - Dec 2017		USD	-	-	-	-	-	-	5,000	(0.75)	-
Swap	Oct 2017 - Dec 2018		USD	-	-	-	-	-	-	10,000	(1.03)	-
Swap	Jan 2018 - Dec 2018		USD	-	-	-	-	-	-	20,000	(0.95)	-
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	Jan 2017 - Dec 2017		USD	-	-	-	-	-	-	5,000	3.00	-
Swap	Jan 2018 - Dec 2018		USD	-	-	-	-	-	-	10,000	3.10	-
Swaption	Jan 2018 - Dec 2018	Oct 31, 2017	USD	-	-	-	-	-	-	5,000	3.10	-

(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.

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												
Collar	Oct 2016 - Sep 2017		GBP	5,000	3.25	10,000	4.03	-	-	-	-	-
Collar	Oct 2016 - Dec 2017		GBP	5,000	3.25	10,000	4.07	-	-	-	-	-
Collar	Jan 2017 - Dec 2017		GBP	5,000	3.30	7,500	3.77	-	-	-	-	-
Collar	Jan 2018 - Dec 2018		GBP	2,500	3.15	2,500	3.82	-	-	-	-	-
Swap	Jan 2017 - Dec 2017		GBP	-	-	-	-	-	-	2,500	4.22	2,500
Swap	Apr 2017 - Mar 2018		GBP	-	-	-	-	-	-	5,300	4.20	-
Swap	Jul 2017 - Dec 2017		GBP	-	-	-	-	-	-	2,500	3.95	-
Swap	Jan 2018 - Dec 2018		GBP	-	-	-	-	-	-	2,500	4.04	5,000
NBP Basis (NBP less NYMEX HH)												
Collar	Jan 2017 - Dec 2017		USD	2,500	1.85	2,500	4.00	-	-	-	-	-
TTF												
3-Way Collar	Apr 2017 - Sep 2017		EUR	9,827	4.18	9,827	5.06	9,827	3.08	-	-	-
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	7,370	5.00	7,370	5.54	7,370	3.57	-	-	-
Collar	Jul 2016 - Mar 2018		EUR	2,457	5.61	4,913	6.90	-	-	-	-	-
Collar	Oct 2016 - Dec 2017		EUR	2,457	5.28	2,457	6.21	-	-	-	-	-
Collar	Jan 2017 - Dec 2017		EUR	9,827	5.06	22,111	6.37	-	-	-	-	-
Collar	Apr 2017 - Sep 2017		EUR	2,457	3.81	4,913	4.47	-	-	-	-	-
Collar	Jan 2018 - Dec 2018		EUR	4,913	4.40	4,913	5.31	-	-	-	-	-
Swap	Jul 2016 - Jun 2018		EUR	-	-	-	-	-	-	2,559	5.89	-
Swap	Jan 2017 - Dec 2017		EUR	-	-	-	-	-	-	2,457	5.32	2,457
Swap	Apr 2017 - Jun 2018		EUR	-	-	-	-	-	-	4,299	4.50	-
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	Jan 2019 - Dec 2019		EUR	-	-	-	-	-	-	2,457	4.92	-
Put Spread	Apr 2017 - Sep 2017		EUR	14,740	4.40	-	-	14,740	3.15	-	-	-
Swaption	Jul 2018 - Dec 2019	Oct 31, 2017	EUR	-	-	-	-	-	-	4,913	4.98	-

Fuel and Electricity	Period	Currency	Swap Volume (unit/d)	Weighted Average Swap price / unit
AESO (mwh)				
Swap	Jan 2017 - Dec 2017	CAD	65	33.47

Interest Rate	Period	Currency	Notional amount	Rate (%)
CDOR SWAP	Sep 2015 - Sep 2019	CAD	100,000,000	1.00
CDOR SWAP	Oct 2015 - Oct 2019	CAD	100,000,000	1.10

Cross Currency Interest Rate	Period	Receive Notional amount(USD)	Rate (USD%)	Pay Notional amount(CAD)	Rate (CAD%)
Swap [(3)]	Jul 2017	587,615,392	2.73	775,800,000	2.31

(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.

(3) In July 2017, Vermilion repaid $0.6 billion of borrowings on the revolving credit facility bearing interest at CDOR plus applicable margins and simultaneously borrowed US $0.5 billion on the revolving credit facility bearing interest at LIBOR plus applicable margins.

Supplemental Table 3: Capital Expenditures and Acquisitions

	Three Months Ended			Six Months Ended	
By classification ($M)	**Jun 30, 2017**	**Mar 31, 2017**	**Jun 30, 2016**	**Jun 30, 2017**	**Jun 30, 2016**
Drilling and development	**57,681**	95,164	71,296	**152,845**	134,069
Exploration and evaluation	**1,194**	725	418	**1,919**	418
Capital expenditures	**58,875**	95,889	71,714	**154,764**	134,487
Property acquisitions	**993**	2,620	8,550	**3,613**	9,420
Acquisitions	**993**	2,620	8,550	**3,613**	9,420

	Three Months Ended			Six Months Ended	
By category ($M)	**Jun 30, 2017**	**Mar 31, 2017**	**Jun 30, 2016**	**Jun 30, 2017**	**Jun 30, 2016**
Land	**1,103**	1,445	493	**2,548**	1,532
Seismic	**2,028**	2,011	1,323	**4,039**	7,591
Drilling and completion	**19,942**	55,386	36,542	**75,328**	64,395
Production equipment and facilities	**27,146**	30,176	35,612	**57,322**	41,850
Recompletions	**4,071**	5,501	768	**9,572**	4,366
Other	**4,585**	1,370	(3,024)	**5,955**	14,753
Capital expenditures	**58,875**	95,889	71,714	**154,764**	134,487
Acquisitions	**993**	2,620	8,550	**3,613**	9,420
Total capital expenditures and acquisitions	**59,868**	98,509	80,264	**158,377**	143,907

	Three Months Ended			Six Months Ended	
Capital expenditures by country ($M)	**Jun 30, 2017**	**Mar 31, 2017**	**Jun 30, 2016**	**Jun 30, 2017**	**Jun 30, 2016**
Canada	**20,599**	57,457	5,619	**78,056**	35,390
France	**16,682**	20,916	12,772	**37,598**	26,235
Netherlands	**5,973**	1,712	8,566	**7,685**	11,562
Germany	**326**	906	592	**1,232**	1,131
Ireland	**(73)**	(804)	2,172	**(877)**	5,248
Australia	**9,158**	3,438	39,939	**12,596**	47,766
United States	**5,155**	11,539	1,636	**16,694**	6,737
Corporate	**1,055**	725	418	**1,780**	418
Total capital expenditures	**58,875**	95,889	71,714	**154,764**	134,487

	Three Months Ended			Six Months Ended	
Acquisitions by country ($M)	**Jun 30, 2017**	**Mar 31, 2017**	**Jun 30, 2016**	**Jun 30, 2017**	**Jun 30, 2016**
Canada	**935**	576	796	**1,511**	1,551
Netherlands	**(16)**	16	-	**-**	-
United States	**49**	2,013	5,432	**2,062**	5,547
Corporate	**25**	15	2,322	**40**	2,322
Total acquisitions	**993**	2,620	8,550	**3,613**	9,420

Supplemental Table 4: Production

	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14
Canada												
Crude oil & condensate (bbls/d)	**9,205**	7,987	7,945	8,984	9,453	10,317	10,413	11,030	11,843	12,163	12,681	12,755
NGLs (bbls/d)	**3,745**	2,670	2,444	2,448	2,687	2,633	2,710	2,678	2,094	1,706	1,444	1,005
Natural gas (mmcf/d)	**93.68**	85.74	75.12	77.62	87.44	97.16	87.90	71.94	64.66	61.78	58.36	57.07
Total (boe/d)	**28,563**	24,947	22,910	24,368	26,713	29,141	27,773	25,698	24,713	24,165	23,851	23,272
% of consolidated	**43%**	38%	38%	37%	42%	44%	45%	47%	48%	48%	49%	47%
France												
Crude oil (bbls/d)	**11,368**	10,834	11,220	11,827	12,326	12,220	12,537	12,310	12,746	11,463	11,133	11,111
Natural gas (mmcf/d)	**-**	0.01	0.38	0.42	0.54	0.44	1.36	1.47	1.03	-	-	-
Total (boe/d)	**11,368**	10,836	11,283	11,897	12,416	12,293	12,763	12,555	12,917	11,463	11,133	11,111
% of consolidated	**17%**	17%	19%	19%	19%	19%	21%	22%	25%	23%	22%	22%
Netherlands												
Condensate (bbls/d)	**104**	76	57	86	96	114	110	109	112	63	81	63
Natural gas (mmcf/d)	**31.58**	39.92	41.15	47.62	49.18	53.40	56.34	53.56	32.43	36.41	31.35	38.07
Total (boe/d)	**5,368**	6,729	6,915	8,023	8,293	9,015	9,500	9,035	5,517	6,132	5,306	6,407
% of consolidated	**8%**	10%	11%	13%	13%	14%	16%	16%	11%	12%	11%	13%
Germany												
Crude oil (bbls/d)	**1,047**	989	-	-	-	-	-	-	-	-	-	-
Natural gas (mmcf/d)	**19.86**	19.39	14.80	14.52	14.31	15.96	16.17	14.00	16.18	16.80	17.71	15.38
Total (boe/d)	**4,357**	4,220	2,467	2,420	2,385	2,660	2,695	2,333	2,696	2,801	2,952	2,563
% of consolidated	**6%**	7%	4%	4%	4%	4%	4%	4%	5%	6%	6%	5%
Ireland												
Natural gas (mmcf/d)	**63.81**	64.82	62.92	59.28	47.26	33.90	0.12	-	-	-	-	-
Total (boe/d)	**10,634**	10,803	10,486	9,879	7,877	5,650	20	-	-	-	-	-
% of consolidated	**16%**	17%	17%	16%	12%	9%	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	**6,054**	6,581	6,388	6,562	6,083	6,180	7,824	6,433	5,865	5,672	6,134	6,567
% of consolidated	**9%**	10%	10%	10%	9%	9%	13%	11%	11%	11%	12%	13%
United States												
Crude oil (bbls/d)	**747**	365	362	383	458	368	420	226	123	153	195	-
NGLs (bbls/d)	**76**	24	23	30	26	39	29	-	-	-	-	-
Natural gas (mmcf/d)	**0.44**	0.20	0.18	0.20	0.20	0.26	0.20	-	-	-	-	-
Total (boe/d)	**896**	422	414	447	518	450	483	226	123	153	195	-
% of consolidated	**1%**	1%	1%	1%	1%	1%	1%	-	-	-	-	-
Consolidated												
Crude oil, condensate & NGLs (bbls/d)	**32,346**	29,526	28,439	30,320	31,129	31,871	34,043	32,786	32,783	31,220	31,668	31,501
% of consolidated	**48%**	46%	47%	48%	48%	49%	56%	58%	63%	62%	64%	63%
Natural gas (mmcf/d)	**209.36**	210.07	194.54	199.65	198.93	201.11	162.09	140.97	114.29	115.00	107.42	110.52
% of consolidated	**52%**	54%	53%	52%	52%	51%	44%	42%	37%	38%	36%	37%
Total (boe/d)	**67,240**	64,537	60,863	63,596	64,285	65,389	61,058	56,280	51,831	50,386	49,571	49,920

	YTD 2017	2016	2015	2014	2013	2012
Canada						
Crude oil & condensate (bbls/d)	**8,599**	9,171	11,357	12,491	8,387	7,659
NGLs (bbls/d)	**3,210**	2,552	2,301	1,233	1,666	1,232
Natural gas (mmcf/d)	**89.73**	84.29	71.65	55.67	42.39	37.50
Total (boe/d)	**26,765**	25,771	25,598	23,001	17,117	15,142
% of consolidated	**40%**	40%	46%	47%	41%	40%
France						
Crude oil (bbls/d)	**11,103**	11,896	12,267	11,011	10,873	9,952
Natural gas (mmcf/d)	**-**	0.44	0.97	-	3.40	3.59
Total (boe/d)	**11,103**	11,970	12,429	11,011	11,440	10,550
% of consolidated	**17%**	19%	23%	22%	28%	28%
Netherlands						
Condensate (bbls/d)	**90**	88	99	77	64	67
Natural gas (mmcf/d)	**35.73**	47.82	44.76	38.20	35.42	34.11
Total (boe/d)	**6,044**	8,058	7,559	6,443	5,967	5,751
% of consolidated	**9%**	13%	14%	13%	15%	15%
Germany						
Crude oil (bbls/d)	**1,018**	-	-	-	-	-
Natural gas (mmcf/d)	**19.63**	14.90	15.78	14.99	-	-
Total (boe/d)	**4,289**	2,483	2,630	2,498	-	-
% of consolidated	**7%**	4%	5%	5%	-	-
Ireland						
Natural gas (mmcf/d)	**64.31**	50.89	0.03	-	-	-
Total (boe/d)	**10,718**	8,482	5	-	-	-
% of consolidated	**16%**	13%	-	-	-	-
Australia						
Crude oil (bbls/d)	**6,316**	6,304	6,454	6,571	6,481	6,360
% of consolidated	**10%**	10%	12%	13%	16%	17%
United States						
Crude oil (bbls/d)	**557**	393	231	49	-	-
NGLs (bbls/d)	**50**	29	7	-	-	-
Natural gas (mmcf/d)	**0.32**	0.21	0.05	-	-	-
Total (boe/d)	**660**	457	247	49	-	-
% of consolidated	**1%**	1%	-	-	-	-
Consolidated						
Crude oil, condensate & NGLs (bbls/d)	**30,943**	30,433	32,716	31,432	27,471	25,270
% of consolidated	**47%**	48%	60%	63%	67%	67%
Natural gas (mmcf/d)	**209.71**	198.55	133.24	108.85	81.21	75.20
% of consolidated	**53%**	52%	40%	37%	33%	33%
Total (boe/d)	**65,895**	63,526	54,922	49,573	41,005	37,803

NON-GAAP FINANCIAL MEASURES

This MD&A includes references to certain financial measures which do not have standardized meanings and may not be comparable to similar measures presented by other issuers. These financial measures include fund flows from operations, a measure of profit or loss in accordance with IFRS 8 "Operating Segments" (please see SEGMENTED INFORMATION in the NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS) and net debt, a measure of capital in accordance with IAS 1 "Presentation of Financial Statements" (please see CAPITAL DISCLOSURES in the NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS).

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

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 consider free cash flow to be a key measure as it is used 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.

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, dispositions, 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:

	Three Months Ended			Six Months Ended	
($M)	Jun 30, 2017	Mar 31, 2017	Jun 30, 2016	Jun 30, 2017	Jun 30, 2016
Dividends declared	**77,858**	76,593	74,662	**154,451**	147,509
Shares issued for the Dividend Reinvestment Plan	**(29,241)**	(35,506)	(50,516)	**(64,747)**	(98,506)
Net dividends	**48,617**	41,087	24,146	**89,704**	49,003
Drilling and development	**57,681**	95,164	71,296	**152,845**	134,069
Exploration and evaluation	**1,194**	725	418	**1,919**	418
Asset retirement obligations settled	**2,120**	2,249	2,200	**4,369**	4,224
Payout	**109,612**	139,225	98,060	**248,837**	187,714

	As at		
('000s of shares)	Jun 30, 2017	Mar 31, 2017	Jun 30, 2016
Shares outstanding	**120,947**	119,046	116,173
Potential shares issuable pursuant to the VIP	**2,847**	3,089	2,775
Diluted shares outstanding	**123,794**	122,135	118,948

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 3, 4, 5]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Stephen P. Larke [3, 4]
Calgary, Alberta

Loren M. Leiker [6]
Houston, Texas

William F. Madison [5, 6]
Sugar Land, Texas

Timothy R. Marchant [5, 6]
Calgary, Alberta

Anthony Marino
Calgary, Alberta

Robert Michaleski [3, 4]
Calgary, Alberta

Sarah E. Raiss [4, 5]
Calgary, Alberta

William Roby [5, 6]
Katy, Texas

Catherine L. Williams [3, 4]
Calgary, Alberta

[1] Chairman of the Board
[2] Lead Director
[3] Audit Committee
[4] Governance and Human Resources Committee
[5] Health, Safety and Environment Committee
[6] Independent Reserves Committee

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
mbbls	thousand barrels
mcf	thousand cubic feet
mmbtu	million British thermal units
mmcf/d	million cubic feet per day
MWh	megawatt hour
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
Curtis W. Hicks
Executive 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

Daniel Goulet
Director Corporate HSE

Bryce Kremnica
Director Field Operations – Canada Business Unit

Kyle Preston
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

Jenson Tan
Director Business Development

Robert (Bob) J. Engbloom
Corporate Secretary

UNITED STATES
Daniel G. Anderson
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

Darcy Kerwin
Managing Director - France Business Unit

Scott Seatter
Managing Director - Netherlands Business Unit

Albrecht Moehring
Managing Director - Germany 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

Royal Bank of Canada

The Bank of Nova Scotia

Alberta Treasury Branches

Bank of America N.A., Canada Branch

BNP Paribas, 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

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

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

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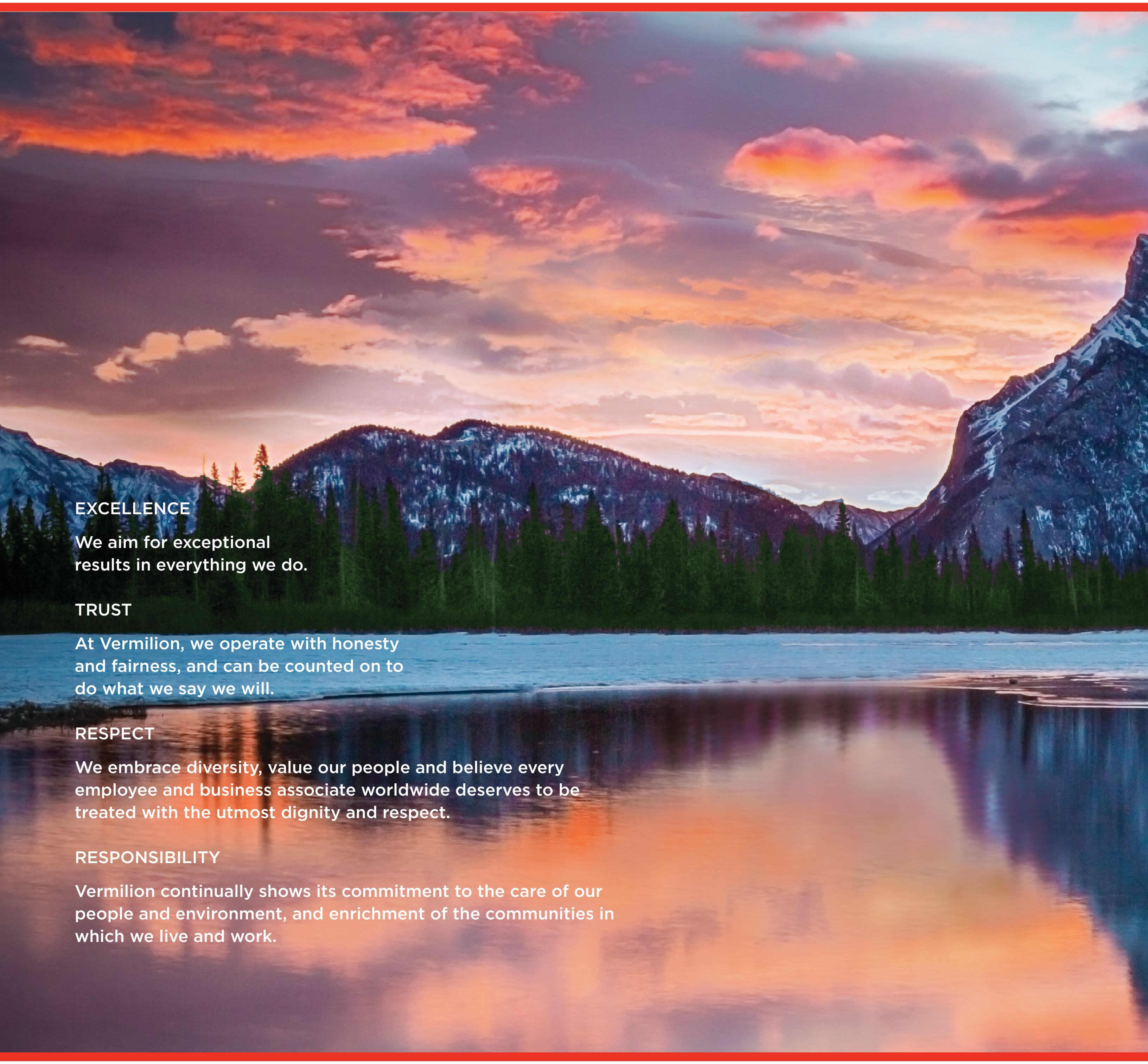

EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

VERMILION ENERGY

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