Q2 2016

MANAGEMENT'S DISCUSSION AND ANALYSIS

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VERMILION ENERGY

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

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

Natural gas volumes have been converted on the basis of six thousand cubic feet of natural gas to one barrel of oil equivalent. Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A"), dated August 4, 2016, 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, 2016 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, 2016 and the audited consolidated financial statements for the year ended December 31, 2015 and 2014, 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, 2016 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.

- Canada business unit: Relates to our assets in Alberta and Saskatchewan.
- France business unit: Relates to our operations in France in the Paris and Aquitaine Basins.
- Netherlands business unit: Relates to our operations in the Netherlands.
- Germany business unit: Relates to our operations in Germany.
- Ireland business unit: Relates to our 18.5% non-operated interest in the Corrib offshore natural gas field.
- Australia business unit: Relates to our operations in the Wandoo offshore crude oil field.
- United States business unit: Relates to our operations in Wyoming in the Powder River Basin.
- Corporate: Includes expenditures 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 a specific business unit.

CHANGE IN PRESENTATION

Prior to 2016, we reported our condensate production in Canada and the Netherlands business units within the NGLs production line. Beginning in Q1 2016, we now report condensate production 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). Comparative periods have been adjusted to reflect this change.

2016 GUIDANCE

On November 9, 2015 we announced preliminary 2016 capital expenditure guidance of $350 million and production guidance of between 63,000-65,000 boe/d. On January 5, 2016, in response to the continued weakness in commodity prices we reduced our 2016 capital expenditure guidance to $285 million with corresponding production guidance of 62,500-63,500 boe/d. On February 29, 2016, we further revised our 2016 capital expenditure guidance to $235 million as a result of continued commodity price deterioration. We maintained our production guidance of 62,500-63,500 boe/d. The February 29, 2016 reduction primarily reflected lower expected non-operated drilling activity in Canada, fewer workovers in France, and a deferral of our Netherlands pipeline twinning program. On August 8, 2016, we modestly increased our 2016 capital expenditure guidance to $240 million with the reinstatement of a four-well drilling program in the Champotran field in France and added drilling activity in Canada, partially offset by capital cost savings achieved to date.

The following table summarizes our 2016 guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2016 Guidance			
2016 Guidance	November 9, 2015	350	63,000 to 65,000
2016 Guidance	January 5, 2016	285	62,500 to 63,500
2016 Guidance	February 29, 2016	235	62,500 to 63,500
2016 Guidance	August 8, 2016	240	62,500 to 63,500

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change		Six Months Ended		% change
	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Q2/16 vs. Q1/16	Q2/16 vs. Q2/15	Jun 30, 2016	Jun 30, 2015	2016 vs. 2015
Production								
Crude oil and condensate (bbls/d)	28,416	29,199	30,689	(3%)	(7%)	28,808	30,104	(4%)
NGLs (bbls/d)	2,713	2,672	2,094	2%	30%	2,693	1,901	42%
Natural gas (mmcf/d)	198.93	201.11	114.29	(1%)	74%	200.02	114.64	74%
Total (boe/d)	64,285	65,389	51,831	(2%)	24%	64,837	51,113	27%
Build (draw) in inventory (mbbls)	70	142	(121)			212	262	
Financial metrics								
Fund flows from operations ($M)	126,568	93,667	129,496	35%	(2%)	220,235	250,291	(12%)
Per share ($/basic share)	1.10	0.83	1.18	33%	(7%)	1.93	2.31	(16%)
Net (loss) earnings	(55,696)	(85,848)	6,813	(35%)	(917%)	(141,544)	8,088	(1,850%)
Per share ($/basic share)	(0.48)	(0.76)	0.06	(37%)	(900%)	(1.24)	0.07	(1,871%)
Net debt ($M)	1,398,950	1,367,063	1,377,902	2%	2%	1,398,950	1,377,902	2%
Cash dividends ($/share)	0.645	0.645	0.645	-	-	1.290	1.290	-
Activity								
Capital expenditures ($M)	71,714	62,773	90,173	14%	(20%)	134,487	264,484	(49%)
Acquisitions ($M)	8,550	870	480	883%	1,681%	9,420	515	1,729%
Gross wells drilled	4.00	12.00	5.00			16.00	34.00	
Net wells drilled	3.14	8.26	3.61			11.40	23.65	

Operational review

- Consolidated average production of 64,285 boe/d in Q2 2016 was a 2% decrease from Q1 2016 due to lower production in Canada and the Netherlands, driven by planned downtime, offset by increased production from Ireland.
- Increased consolidated average production for the three and six months ended June 30, 2016, by 24% and 27%, respectively, versus the comparable periods in 2015. These increases were primarily due to the addition of Corrib production in Ireland, as well as production growth in Canada, the Netherlands, the US, and Australia business units.
- Executed capital expenditures totalling $71.7 million, primarily in Australia where capital expenditures of $39.9 million were incurred related to the two-well sidetrack drilling program.

Financial review

Net (loss) earnings

- The net loss for Q2 2016 was $55.7 million ($0.48/basic share), as compared to a net loss of $85.8 million ($0.76/basic share) in Q1 2016. The decrease in the net loss was primarily attributable to higher revenues as a result of stronger crude oil pricing.
- The net loss for Q2 2016 of $55.7 million is compared to net earnings of $6.8 million in Q2 2015. The change was a result of lower petroleum and natural gas sales as a result of lower commodity prices, as well as higher depletion and depreciation charges associated with higher sold volumes. The net loss for the six months ended June 30, 2016 of $141.5 million compared to net earnings of $8.8 million for the comparable period in the prior year. The change was a result of lower petroleum and natural gas sales as a result of lower commodity prices, higher depletion and depreciation charges associated with higher sold volumes, and the absence of a $31.8 million court-awarded recovery recognized in Q1 2015.

Fund flows from operations

- Generated fund flows from operations of $126.6 million during Q2 2016, an increase of 35% from Q1 2016. This quarter-over-quarter increase was primarily driven by higher crude oil pricing and global cost reductions, including a 6% decrease in per unit operating expense.
- Fund flows from operations decreased by 2% and 12% for the three and six months ended June 30, 2016, respectively, versus the comparable periods in the prior year. This decrease was the result of lower pricing for all commodities, partially offset by higher sold volumes, including the impact of six months of production from Corrib, and global cost reductions. The six months ended June 30, 2016, was also impacted by the absence of the $31.8 million court-awarded recovery recognized in Q1 2015.

Net debt

- Net debt remained relatively consistent at $1.40 billion.

Dividends

- Declared dividends of $0.215 per common share per month during the second quarter of 2016, totalling $1.290 per common share for the six months ended June 30, 2016.

COMMODITY PRICES

	Three Months Ended			% change		Six Months Ended		% change
	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Q2/16 vs. Q1/16	Q2/16 vs. Q2/15	Jun 30, 2016	Jun 30, 2015	2016 vs. 2015
Average reference prices								
Crude oil								
WTI (US $/bbl)	45.59	33.45	57.94	36%	(21%)	39.52	53.29	(26%)
Edmonton Sweet index (US $/bbl)	42.51	29.76	55.08	43%	(23%)	36.13	48.46	(25%)
Dated Brent (US $/bbl)	45.57	33.89	61.92	34%	(26%)	39.73	57.95	(31%)
Natural gas								
AECO ($/mmbtu)	1.40	1.83	2.65	(23%)	(47%)	1.61	2.70	(40%)
TTF ($/mmbtu)	5.61	5.70	8.38	(2%)	(33%)	5.66	8.54	(34%)
TTF (€/mmbtu)	3.86	3.76	6.16	3%	(37%)	3.81	6.19	(38%)
NBP ($/mmbtu)	5.78	5.97	8.42	(3%)	(31%)	5.88	8.71	(32%)
NBP (€/mmbtu)	3.97	3.94	6.19	1%	(36%)	3.96	6.32	(37%)
Henry Hub ($/mmbtu)	2.52	2.87	3.25	(12%)	(22%)	2.69	3.47	(22%)
Henry Hub (US $/mmbtu)	1.95	2.09	2.64	(7%)	(26%)	2.02	2.81	(28%)
Average foreign currency exchange rates								
CDN $/US $	1.29	1.37	1.23	(6%)	5%	1.33	1.24	7%
CDN $/Euro	1.46	1.52	1.36	(4%)	7%	1.49	1.38	8%
Average realized prices ($/boe)								
Canada	25.39	21.16	40.59	20%	(37%)	23.18	38.24	(39%)
France	57.82	43.16	71.96	34%	(20%)	50.32	68.52	(27%)
Netherlands	31.77	33.26	47.63	(4%)	(33%)	32.55	48.13	(32%)
Germany	28.94	31.78	43.31	(9%)	(33%)	30.44	44.27	(31%)
Ireland	32.59	33.07	-	(1%)	100%	32.79	-	100%
Australia	61.53	46.93	80.87	31%	(24%)	55.15	81.60	(32%)
United States	46.80	30.10	60.57	55%	(23%)	39.03	54.07	(28%)
Consolidated	36.83	30.53	54.65	21%	(33%)	33.67	51.19	(34%)
Production mix (% of production)								
% priced with reference to WTI	20%	20%	27%			20%	27%	
% priced with reference to AECO	22%	25%	21%			24%	21%	
% priced with reference to TTF and NBP	29%	26%	16%			28%	17%	
% priced with reference to Dated Brent	29%	29%	36%			28%	35%	

- Oil benchmarks saw a sharp quarter-over-quarter rise in price due to seasonal factors as well as unexpected global supply disruptions, primarily from Nigeria and Canada. Averaging US $45.59/bbl in Q2 2016, WTI was up 36% quarter-over-quarter but still down 21% versus the same quarter in 2015. Dated Brent was up 34% quarter-over-quarter but down 26% from the same period in 2015.
- Edmonton Sweet increased 43% quarter-over-quarter to average US $42.51/bbl for Q2 2016. However, Edmonton Sweet prices remained 23% below the same period in 2015.
- Seasonal factors and above-normal gas-in-storage resulted in lower AECO gas prices for Q2 2016. Averaging $1.40/mmbtu during Q2 2016, AECO was down by 23% versus Q1 2016 and 47% versus the same period in 2015.
- European gas markets managed to largely maintain price levels despite the second quarter typically being a seasonally weaker period. Fuel switching and unplanned maintenance were the main drivers behind the relatively flat quarter-over-quarter price for both TTF and NBP. For Q2 2016, TTF averaged $5.61/mmbtu while NBP averaged $5.78/mmbtu, which represented a 2% and 3% quarter-over-quarter decline, respectively.
- The Canadian dollar gained against both the US dollar and the Euro, as stronger oil prices and no change in the US overnight rate benefitted the Canadian dollar. However, the Canadian dollar was weaker on a year-over-year basis.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Six Months Ended			
	Jun 30, 2016		Mar 31, 2016		Jun 30, 2015		Jun 30, 2016		Jun 30, 2015	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	212,855	36.83	177,385	30.53	264,331	54.65	390,240	33.67	460,216	51.19
Royalties	(12,355)	(2.14)	(13,961)	(2.40)	(16,111)	(3.33)	(26,316)	(2.27)	(32,535)	(3.62)
Petroleum and natural gas revenues	200,500	34.69	163,424	28.13	248,220	51.32	363,924	31.40	427,681	47.57
Transportation	(9,860)	(1.71)	(10,390)	(1.79)	(10,883)	(2.25)	(20,250)	(1.75)	(20,423)	(2.27)
Operating	(52,116)	(9.02)	(55,628)	(9.58)	(58,616)	(12.12)	(107,744)	(9.30)	(102,467)	(11.40)
General and administration	(15,493)	(2.68)	(13,577)	(2.34)	(14,505)	(3.00)	(29,070)	(2.51)	(28,065)	(3.12)
PRRT	(144)	(0.02)	(128)	(0.02)	(3,371)	(0.70)	(272)	(0.02)	(5,725)	(0.64)
Corporate income taxes	(5,564)	(0.96)	(3,160)	(0.54)	(17,344)	(3.59)	(8,724)	(0.75)	(34,967)	(3.89)
Interest expense	(13,647)	(2.36)	(14,750)	(2.54)	(14,550)	(3.01)	(28,397)	(2.45)	(27,848)	(3.10)
Realized gain on derivative instruments	21,501	3.72	28,423	4.89	3,081	0.64	49,924	4.31	9,338	1.04
Realized foreign exchange gain (loss)	1,329	0.23	(652)	(0.11)	(2,740)	(0.57)	677	0.06	566	0.06
Realized other income	62	0.01	105	0.02	204	0.04	167	0.01	32,201	3.58
Fund flows from operations	126,568	21.90	93,667	16.12	129,496	26.76	220,235	19.00	250,291	27.83

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

($M)	Q2/16 vs. Q1/16	Q2/16 vs. Q2/15	2016 vs. 2015
Fund flows from operations – Comparative period	93,667	129,496	250,291
Sales volume variance:			
Canada	(4,189)	(3,932)	2,851
France	(2,206)	(4,561)	8,038
Netherlands	(2,060)	11,920	24,800
Germany	(787)	(1,221)	(1,687)
Ireland	6,356	23,360	40,364
Australia	5,778	(11,894)	3,888
United States	263	1,524	2,069
Pricing variance on sold volumes:			
WTI	15,216	(14,157)	(33,494)
AECO	(4,695)	(11,458)	(20,662)
Dated Brent	23,672	(26,072)	(65,509)
TTF and NBP	(1,878)	(14,985)	(30,634)
Changes in:			
Royalties	1,606	3,756	6,219
Transportation	530	1,023	173
Operating	3,512	6,500	(5,277)
General and administration	(1,916)	(988)	(1,005)
PRRT	(16)	3,227	5,453
Corporate income taxes	(2,404)	11,780	26,243
Interest	1,103	903	(549)
Realized derivatives	(6,922)	18,420	40,586
Realized foreign exchange	1,981	4,069	111
Realized other income	(43)	(142)	(32,034)
Fund flows from operations – Current period	126,568	126,568	220,235

Fund flows from operations of $126.6 million during Q2 2016 represented an increase of 35% versus Q1 2016. This increase relates primarily to higher crude oil pricing and global cost reductions, including a 6% decrease in per unit operating expense.

Fund flows from operations decreased by 2% and 12% for the three and six months ended June 30, 2016, respectively, versus the comparable periods in the prior year. This decrease was the result of lower pricing for all commodities, offset by higher sold volumes, including the impact of six months of production from Corrib. The impact of lower pricing was further minimized by global cost reductions, including a 26% and 18% decrease in per unit operating expense for the three and six months ended June 30, 2016, respectively, versus the comparable periods in 2015. Fund flows from operations for the six month period ended June 30, 2016 was also affected by the absence of a $31.8 million court-awarded recovery recognized in Q1 2015.

Fluctuations in fund flows from operations (and correspondingly net (loss) earnings) 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 in income.

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
- Canadian cash flows are fully tax-sheltered for the foreseeable future.

Operational and financial review

	Three Months Ended			% change		Six Months Ended		% change
Canada business unit ($M except as indicated)	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Q2/16 vs. Q1/16	Q2/16 vs. Q2/15	Jun 30, 2016	Jun 30, 2015	2016 vs. 2015
Production								
Crude oil and condensate (bbls/d)	9,453	10,317	11,843	(8%)	(20%)	9,885	12,001	(18%)
NGLs (bbls/d)	2,687	2,633	2,094	2%	28%	2,660	1,901	40%
Natural gas (mmcf/d)	87.44	97.16	64.66	(10%)	35%	92.30	63.23	46%
Total (boe/d)	26,713	29,141	24,713	(8%)	8%	27,928	24,441	14%
Production mix (% of total)								
Crude oil and condensate	35%	35%	48%			35%	49%	
NGLs	10%	9%	8%			10%	8%	
Natural gas	55%	56%	44%			55%	43%	
Activity								
Capital expenditures	5,619	29,771	21,881	(81%)	(74%)	35,390	136,730	(74%)
Acquisitions	796	755	384			1,551	419	
Gross wells drilled	2.00	12.00	1.00			14.00	26.00	
Net wells drilled	1.14	8.26	0.50			9.40	16.54	
Financial results								
Sales	61,731	56,110	91,284	10%	(32%)	117,841	169,168	(30%)
Royalties	(3,770)	(5,498)	(5,768)	(31%)	(35%)	(9,268)	(14,360)	(35%)
Transportation	(3,759)	(4,151)	(4,469)	(9%)	(16%)	(7,910)	(8,411)	(6%)
Operating	(16,460)	(21,343)	(21,534)	(23%)	(24%)	(37,803)	(40,633)	(7%)
General and administration	(4,305)	(2,476)	(5,510)	74%	(22%)	(6,781)	(9,525)	(29%)
Fund flows from operations	33,437	22,642	54,003	48%	(38%)	56,079	96,239	(42%)
Netbacks ($/boe)								
Sales	25.39	21.16	40.59	20%	(37%)	23.18	38.24	(39%)
Royalties	(1.55)	(2.07)	(2.56)	(25%)	(39%)	(1.82)	(3.25)	(44%)
Transportation	(1.55)	(1.57)	(1.99)	(1%)	(22%)	(1.56)	(1.90)	(18%)
Operating	(6.77)	(8.05)	(9.58)	(16%)	(29%)	(7.44)	(9.19)	(19%)
General and administration	(1.77)	(0.94)	(2.45)	88%	(28%)	(1.33)	(2.15)	(38%)
Fund flows from operations netback	13.75	8.53	24.01	61%	(43%)	11.03	21.75	(49%)
Realized prices								
Crude oil and condensate ($/bbl)	56.67	39.69	67.10	43%	(16%)	47.81	59.95	(20%)
NGLs ($/bbl)	9.56	7.31	13.62	31%	(30%)	8.45	17.53	(52%)
Natural gas ($/mmbtu)	1.34	1.93	2.78	(31%)	(52%)	1.65	2.88	(43%)
Total ($/boe)	25.39	21.16	40.59	20%	(37%)	23.18	38.24	(39%)
Reference prices								
WTI (US $/bbl)	45.59	33.45	57.94	36%	(21%)	39.52	53.29	(26%)
Edmonton Sweet index (US $/bbl)	42.51	29.76	55.08	43%	(23%)	36.13	48.46	(25%)
Edmonton Sweet index ($/bbl)	54.78	40.91	67.72	34%	(19%)	48.11	59.86	(20%)
AECO ($/mmbtu)	1.40	1.83	2.65	(23%)	(47%)	1.61	2.70	(40%)

Production

- Q2 2016 average production in Canada decreased by 8% quarter-over-quarter, mainly driven by a planned turnaround at our West Pembina battery, production declines, and voluntary gas-weighted production curtailment of approximately 6 mmcf/d (1,000 boe/d) over the quarter in response to low AECO prices. Q2 2016 production increased 8% year-over-year, primarily attributable to strong organic production growth in our Mannville condensate-rich gas resource play.
- Cardium production averaged approximately 6,700 boe/d in Q2 2016, a 10% decrease quarter-over-quarter.
- Mannville production averaged approximately 11,500 boe/d in Q2 2016, a 12% decrease quarter-over-quarter but more than double Q2 2015 production of approximately 5,600 boe/d.
- Production from our southeast Saskatchewan assets averaged approximately 2,800 boe/d in Q2 2016, an increase of 5% quarter-over-quarter.

Activity review

- Vermilion drilled one (1.0 net) operated well and participated in the drilling of one (0.1 net) non-operated well during Q2 2016.

  Cardium
  - In Q2 2016, no new operated wells were drilled, completed or brought on production. One (0.1 net) non-operated well was drilled, completed and brought on production during the quarter.
  - 2016 activity includes drilling three (3.0 net) operated wells, in addition to the optimization of existing assets.

  Mannville
  - During Q2 2016, one (0.3 net) non-operated well was completed and two (0.8 net) non-operated wells were brought on production.
  - In 2016, we plan to drill or participate in 13 (7.8 net) wells; six (3.8 net) wells have been drilled to date.

  Saskatchewan
  - We drilled one (1.0 net) operated Midale well during Q2 2016, which we plan to complete and bring on production in Q1 2017 along with the three operated wells drilled in Q1 2016. One (0.5 net) non-operated well drilled in Q1 2016 was tied in and brought on production during the quarter.
  - We have drilled and participated in seven (5.5 net) wells, completing our 2016 planned capital activity.

Sales

- The realized price for our crude oil and condensate production in Canada is directly linked to WTI, but 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 spot price in Canada.
- Q2 2016 sales per boe increased versus Q1 2016 due to strengthening crude oil pricing.
- Sales per boe for the three and six months ended June 30, 2016 decreased versus the comparable periods in 2015, largely as a result of lower crude oil and natural gas pricing.

Royalties

- Royalties as a percentage of sales for Q2 2016 decreased to 6.1% as compared to 9.8% in Q1 2016 as a result of an annual favourable gas cost allowance adjustment in Alberta resulting in gas royalties being in a recovery position for the current quarter.
- Royalties as a percentage of sales for the three and six months ended June 30, 2016 decreased to 6.1% and 7.9% versus 6.3% and 8.5% for the comparable 2015 periods due to the impact of lower reference prices on the sliding scale used to determine crude oil royalty rates.

Transportation

- Transportation expense relates to the delivery of crude oil and natural gas production to major pipelines where legal title transfers.
- Transportation expense for Q2 2016 was lower than Q1 2016 as a result of lower production.
- Transportation expense for the three and six months ended June 30, 2016 was lower for both periods in absolute dollars while production increased. This was primarily the result of production having an increased natural gas weighting, which has a lower per unit transportation cost relative to crude oil, condensate and NGLs.

Operating

- Operating expense reductions of 23% in Q2 2016 versus Q1 2016, resulting in a 16% reduction in per unit costs for the second consecutive quarter. Our cost control and cost-cutting initiatives, including service cost negotiations impacting numerous cost drivers, have resulted in these cost reductions.
- Operating expenses were lower on an absolute dollar basis for the three and six months ended June 30, 2016 compared to the same periods in 2015 by 24% and 7% respectively. As a result of the cost control and cost-cutting initiatives, these reductions were achieved while increasing production, resulting in year-over-year per unit decreases of 29% and 19%.

General and administration

- General and administration expense fluctuation in Q2 2016 as compared to Q1 2016 was the result of expenditure timing.
- Year-over-year, general and administration expense for the six months ended June 30, 2016 was 29% lower than the comparable period in 2015 due to cost-cutting initiatives to reduce our cost structure and preserve balance sheet strength.

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.
- Producing assets include large conventional oil fields with high working interests located in the Aquitaine and Paris Basins, containing an identified inventory of workover, infill drilling, and secondary recovery opportunities.
- Production is characterized by Brent-based crude pricing and low base decline rates.

Operational and financial review

	Three Months Ended			% change		Six Months Ended		% change
France business unit ($M except as indicated)	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Q2/16 vs. Q1/16	Q2/16 vs. Q2/15	Jun 30, 2016	Jun 30, 2015	2016 vs. 2015
Production								
Crude oil (bbls/d)	12,326	12,220	12,746	1%	(3%)	12,273	12,108	1%
Natural gas (mmcf/d)	0.54	0.44	1.03	23%	(48%)	0.49	0.52	(6%)
Total (boe/d)	12,416	12,293	12,917	1%	(4%)	12,354	12,194	1%
Inventory (mbbls)								
Opening crude oil inventory	247	243	299			243	197	
Crude oil production	1,122	1,112	1,160			2,234	2,192	
Crude oil sales	(1,057)	(1,108)	(1,119)			(2,165)	(2,049)	
Closing crude oil inventory	312	247	340			312	340	
Activity								
Capital expenditures	12,772	13,463	16,697	(5%)	(24%)	26,235	50,811	(48%)
Acquisitions	-	-	96			-	96	
Gross wells drilled	-	-	-			-	4.00	
Net wells drilled	-	-	-			-	4.00	
Financial results								
Sales	61,591	48,125	81,627	28%	(25%)	109,716	141,459	(22%)
Royalties	(6,564)	(6,766)	(6,620)	(3%)	(1%)	(13,330)	(11,722)	14%
Transportation	(3,476)	(3,713)	(3,526)	(6%)	(1%)	(7,189)	(6,537)	10%
Operating	(11,265)	(14,320)	(12,102)	(21%)	(7%)	(25,585)	(22,928)	12%
General and administration	(4,734)	(4,676)	(4,874)	1%	(3%)	(9,410)	(9,985)	(6%)
Other income	-	-	-	-	-	-	31,775	(100%)
Current income taxes	(921)	(34)	(9,316)	2,609%	(90%)	(955)	(23,597)	(96%)
Fund flows from operations	34,631	18,616	45,189	86%	(23%)	53,247	98,465	(46%)
Netbacks ($/boe)								
Sales	57.82	43.16	71.96	34%	(20%)	50.32	68.52	(27%)
Royalties	(6.16)	(6.07)	(5.84)	1%	5%	(6.11)	(5.68)	8%
Transportation	(3.26)	(3.33)	(3.11)	(2%)	5%	(3.30)	(3.17)	4%
Operating	(10.57)	(12.84)	(10.67)	(18%)	(1%)	(11.73)	(11.11)	6%
General and administration	(4.44)	(4.19)	(4.30)	6%	3%	(4.32)	(4.84)	(11%)
Other income	-	-	-	-	-	-	15.39	(100%)
Current income taxes	(0.86)	(0.03)	(8.21)	2,767%	(90%)	(0.44)	(11.43)	(96%)
Fund flows from operations netback	32.53	16.70	39.83	95%	(18%)	24.42	47.68	(49%)
Realized prices								
Crude oil ($/bbl)	58.19	43.36	72.83	34%	(20%)	50.60	68.97	(27%)
Natural gas ($/mmbtu)	1.58	1.66	1.53	(5%)	3%	1.62	1.53	6%
Total ($/boe)	57.82	43.16	71.96	34%	(20%)	50.32	68.52	(27%)
Reference prices								
Dated Brent (US $/bbl)	45.57	33.89	61.92	34%	(26%)	39.73	57.95	(31%)
Dated Brent ($/bbl)	58.72	46.59	76.12	26%	(23%)	52.91	71.59	(26%)

Production

- Production increased 1% versus the prior quarter. Year-over-year production decreased 4%, due to the impact of production additions from our Champotran drilling program in 2015 and third party restrictions impacting Vic Bilh gas production.

Activity review

- During the quarter we completed a number of workover and optimization programs in the Aquitaine and Paris Basins.
- In 2016, our planned capital activity includes a four-well drilling program in Champotran, and approximately 15 well workovers in the Aquitaine and Paris Basins.

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Q2 2016 sales per boe increased versus Q1 2016 due to strengthening crude oil pricing.
- Sales per boe for the three and six months ended June 30, 2016 decreased versus the comparable periods in 2015 as a result of weakening crude oil pricing.

Royalties

- Royalties in France relate to two components: RCDM (levied on units of production and not subject to changes in commodity prices) and R31 (based on a percentage of sales).
- Royalties as a percentage of sales was 10.7% and 12.1% for the three and six months ended June 30, 2016, a decrease from the 14.1% realized in Q1 2016 and an increase over the comparable periods in 2015. These fluctuations in royalties as a percentage of sales were the result of fixed per unit RCDM royalties.

Transportation

- Transportation expense for the three months ended June 30, 2016 was relatively consistent with Q1 2016 and Q2 2015.
- Transportation expense for the six months ended June 30, 2016 increased by 10% compared to the prior year due to a 6% increase in volumes sold and an 8% depreciation in the Canadian dollar relative to the Euro. After adjusting for the unfavourable foreign exchange impact, per unit transportation costs decreased by 4% year-over-year due to successful vessel cost renegotiations and a lower level of project activity at the Ambès terminal.

Operating

- Operating expense decreased by 21% from Q1 2016 primarily due to decreases in electricity pricing, electricity consumption and lower downhole maintenance costs. In addition, an inventory build and a favourable foreign exchange adjustment as the Euro weakened relative to the Canadian dollar resulted in lower costs.
- Operating expense on a dollar basis decreased 7% for the three months ended June 30, 2016 and increased 12% for the six months ended June 30, 2016 versus the same periods in 2015. An ongoing focus on cost reduction initiatives and savings from contract renegotiations helped offset an unfavourable foreign exchange expense in both periods. After normalizing for the unfavourable foreign exchange impact, per unit costs have decreased 7% and 2% respectively for the three and six months ended June 30, 2016.

General and administration

- General and administration expense for the three and six months ended June 30, 2016 decreased by 3% and 6% respectively compared to the prior year due to cost reduction initiatives.

Current income taxes

- In France, current income taxes are applied to taxable income, after eligible deductions, at a statutory rate of 34.4% for 2016. For 2016, the effective rate on current taxes is expected to be between approximately 1% to 3% of pre-tax fund flows from operations. This is subject to change in response to commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Current income taxes in Q2 2016 were higher compared to Q1 2016 and lower compared to Q2 2015 due to the respective change in sales.
- Current income taxes for the six months ended June 30, 2016 were lower versus the comparative period in 2015 as a result of decreased sales.

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

	Three Months Ended			% change		Six Months Ended		% change
Netherlands business unit ($M except as indicated)	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Q2/16 vs. Q1/16	Q2/16 vs. Q2/15	Jun 30, 2016	Jun 30, 2015	2016 vs. 2015
Production								
Condensate (bbls/d)	96	114	112	(16%)	(14%)	105	88	19%
Natural gas (mmcf/d)	49.18	53.40	32.43	(8%)	52%	51.29	34.41	49%
Total (boe/d)	8,293	9,015	5,517	(8%)	50%	8,654	5,823	49%
Activity								
Capital expenditures	8,566	2,996	18,885	186%	(55%)	11,562	23,218	(50%)
Gross wells drilled	-	-	2.00			-	2.00	
Net wells drilled	-	-	1.86			-	1.86	
Financial results								
Sales	23,973	27,286	23,913	(12%)	-	51,259	50,731	1%
Royalties	(396)	(460)	(1,294)	(14%)	(69%)	(856)	(2,220)	(61%)
Operating	(4,306)	(5,976)	(5,414)	(28%)	(20%)	(10,282)	(11,240)	(9%)
General and administration	(1,223)	(773)	(454)	58%	169%	(1,996)	(1,191)	68%
Current income taxes	(3,260)	(2,200)	(2,347)	48%	39%	(5,460)	(4,735)	15%
Fund flows from operations	14,788	17,877	14,404	(17%)	3%	32,665	31,345	4%
Netbacks ($/boe)								
Sales	31.77	33.26	47.63	(4%)	(33%)	32.55	48.13	(32%)
Royalties	(0.52)	(0.56)	(2.58)	(7%)	(80%)	(0.54)	(2.11)	(74%)
Operating	(5.71)	(7.28)	(10.78)	(22%)	(47%)	(6.53)	(10.66)	(39%)
General and administration	(1.62)	(0.94)	(0.90)	72%	80%	(1.27)	(1.13)	12%
Current income taxes	(4.32)	(2.68)	(4.67)	61%	(7%)	(3.47)	(4.49)	(23%)
Fund flows from operations netback	19.60	21.80	28.70	(10%)	(32%)	20.74	29.74	(30%)
Realized prices								
Condensate ($/bbl)	45.05	32.24	53.28	40%	(15%)	38.10	53.15	(28%)
Natural gas ($/mmbtu)	5.27	5.55	7.92	(5%)	(33%)	5.41	8.01	(32%)
Total ($/boe)	31.77	33.26	47.63	(4%)	(33%)	32.55	48.13	(32%)
Reference prices								
TTF ($/mmbtu)	5.61	5.70	8.38	(2%)	(33%)	5.66	8.54	(34%)
TTF (€/mmbtu)	3.86	3.76	6.16	3%	(37%)	3.81	6.19	(38%)

Production

- Q2 2016 production decreased 8% versus the prior quarter mainly due to downtime associated with the installation of permanent wellsite facilities for the Slootdorp-06/07 wells.
- Year-over-year production increased 50%, primarily due to production additions from Diever-02 and Slootdorp-06/07 wells, and enhanced by debottlenecking at our Garijp Treatment Centre. The Diever-02 exploration well (45% working interest), which came on an extended production test in late October 2015, continues to produce approximately 15 mmcf/d (2,500 boe/d), net to Vermilion.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

Activity review

- Installed permanent wellsite facilities for the Slootdorp-06/07 wells during Q2 2016.
- Planning activities for the drilling of Langezwaag-03 (42% working interest) and Andel-6ST (45% working interest) were carried out during the quarter. We expect to drill these wells in Q3 2016, and if successful, we expect to have the wells on production prior to year end.

Sales

- The price of our natural gas in the Netherlands is based on the TTF day-ahead index. GasTerra, a state owned entity, continues to purchase all of the natural gas we produce in the Netherlands.
  Sales per boe decreased versus all comparable periods, consistent with a decrease in the TTF reference price. Compared to the comparable periods in 2015, the decrease in price was entirely offset by increased production.

Royalties

- In the Netherlands, we pay overriding royalties on certain wells associated with an acquisition completed by the Netherlands business unit in October 2013. As such, fluctuations in royalty expense in the periods presented relate 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

- Operating expense on a dollar basis decreased versus Q1 2016 by 28% due to continued focus on cost-cutting initiatives.
- For the three and six months ended June 30, 2016 operating expense was lower on a dollar and per unit basis compared to the same periods in 2015. Our ongoing focus on cost control, while increasing year-over-year volumes by approximately 50%, resulted in per unit cost decreases of 47% and 39% for the three and six months ended June 30, 2016 versus the comparable periods in 2015.

General and administration

- Variances in general and administration expense generally relate to timing of expenditures, including the timing of allocations from Vermilion's Corporate segment.

Current income taxes

- In the Netherlands, current income taxes are applied to taxable income, after eligible deductions, at an implied tax rate of approximately 46%. For 2016, the effective rate on current taxes is expected to be between approximately 15% and 17% of pre-tax fund flows from operations. This rate is subject to change in response to commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Current income taxes in Q2 2016 were higher compared to Q1 2016 as decreased revenues were offset by the impact of changes to the 2016 full year tax estimates. Q2 2016 current income taxes were higher compared to Q2 2015 as result of increased pre-tax fund flows from operations.
- Q2 2016 year-to-date current income taxes were higher compared to the comparative period in 2015 as a result of increased pre-tax fund flows from operations.

GERMANY BUSINESS UNIT

Overview
- Vermilion entered Germany in February 2014.
- 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 110,000 net acres (100% working interest) across two exploration licenses in Lower Saxony in 2016.

Operational and financial review

Germany business unit ($M except as indicated)	Three Months Ended Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	% change Q2/16 vs. Q1/16	Q2/16 vs. Q2/15	Six Months Ended Jun 30, 2016	Jun 30, 2015	% change 2016 vs. 2015
Production								
Natural gas (mmcf/d)	14.31	15.96	16.18	(10%)	(12%)	15.13	16.49	(8%)
Total (boe/d)	2,385	2,660	2,696	(10%)	(12%)	2,522	2,748	(8%)
Activity								
Capital expenditures	592	539	3,231	10%	(82%)	1,131	4,199	(73%)
Gross wells drilled	-	-	1.00			-	1.00	
Net wells drilled	-	-	0.25			-	0.25	
Financial results								
Sales	6,280	7,692	10,626	(18%)	(41%)	13,972	22,021	(37%)
Royalties	(964)	(867)	(2,238)	11%	(57%)	(1,831)	(3,836)	(52%)
Transportation	(1,051)	(887)	(1,240)	18%	(15%)	(1,938)	(2,134)	(9%)
Operating	(2,506)	(2,593)	(1,373)	(3%)	83%	(5,099)	(3,372)	51%
General and administration	(2,474)	(2,428)	(1,435)	2%	72%	(4,902)	(3,043)	61%
Fund flows from operations	(715)	917	4,340	(178%)	(116%)	202	9,636	(98%)
Netbacks ($/boe)								
Sales	28.94	31.78	43.31	(9%)	(33%)	30.44	44.27	(31%)
Royalties	(4.44)	(3.58)	(9.12)	24%	(51%)	(3.99)	(7.71)	(48%)
Transportation	(4.84)	(3.67)	(5.05)	32%	(4%)	(4.22)	(4.29)	(2%)
Operating	(11.55)	(10.71)	(5.60)	8%	106%	(11.11)	(6.78)	64%
General and administration	(11.40)	(10.03)	(5.85)	14%	95%	(10.68)	(6.12)	75%
Fund flows from operations netback	(3.29)	3.79	17.69	(187%)	(119%)	0.44	19.37	(98%)
Reference prices								
TTF ($/mmbtu)	5.61	5.70	8.38	(2%)	(33%)	5.66	8.54	(34%)
TTF (€/mmbtu)	3.86	3.76	6.16	3%	(37%)	3.81	6.19	(38%)

Production
- Q2 2016 production decreased 10% quarter-over-quarter and 12% year-over-year. Q2 2016 production was impacted by a shut down for pipeline pigging operations.

Activity review
- During Q2 2016, Vermilion entered into a definitive purchase and sale agreement for operated and non-operated interests in five oil and three gas producing fields from Engie E&P Deutschland GmbH, for total consideration of €33 million ($47.9 million). Vermilion will assume operatorship of six of the eight producing fields. For 2016, the assets are expected to produce approximately 2,000 boe/d (50% oil). The acquisition has an effective date of January 1, 2016 and is anticipated to close in late Q4 2016.
- In 2016, the majority of activity will be associated with permitting and pre-drill activities for Burgmoor Z5 and two farm-in prospects, which are planned for 2017. In addition, we will continue our ongoing analysis of the proprietary geologic data associated with the farm-in assets.
-

Sales
- The price of our natural gas in Germany is based on the TTF month-ahead index.
- Sales per boe decreased versus all comparable periods, consistent with a decrease in the TTF reference price.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Royalties as a percentage of sales was 15.4% and 13.1% for the three and six months ended June 30, 2016, a decrease from the 21.1% and 17.4% for the comparable periods in 2015. The decrease is due to unfavourable prior year adjustments impacting 2015.

Transportation

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer.
- Q2 2016 transportation expense increased from Q1 2016 on a total dollar and per unit basis due to an adjustment recorded in the current quarter relating to 2015.
- Transportation expense decreased by 15% and 9% for the three and six months ended June 30, 2016 compared to the same periods in 2015, primarily due to declining production.

Operating

- Operating expenses for Germany primarily relate to tariffs charged for facility operations and gas processing.
- Operating expense for Q2 2016 was consistent with Q1 2016 and increased from Q2 2015 on a total dollar basis due to higher levels of project activity.
- Year-to-date Q2 2016 operating expense increased versus 2015 on a total dollar and per unit basis due to higher levels of project activity.
- We expect per unit operating costs to improve as our production base in Germany grows.

General and administration

- Q2 2016 general and administration expenses were consistent with Q1 2016.
- General and administration costs for the three and six months ended June 30, 2016 are higher compared to 2015 due to higher staffing levels and office costs incurred to support our farm-in agreement, as well as costs incurred to support asset acquisition activity.
- We expect per unit general and administration costs to improve as our production base in Germany grows.

Current income taxes

- Current income taxes in Germany are applied to taxable income, after eligible deductions, at a statutory tax rate of approximately 24.2%. As a function of Vermilion's tax basis in Germany, Vermilion does not presently pay income taxes in Germany.

IRELAND BUSINESS UNIT

Overview

- 18.5% non-operating interest in the offshore Corrib gas field located approximately 83 km off the northwest coast of Ireland.
- Project comprises six offshore wells, offshore and onshore sales and transportation pipeline segments as well as a natural gas processing facility.
- Corrib is expected to produce approximately 58 mmcf/d (9,700 boe/d) net to Vermilion at peak production rates.

Operational and financial review

	Three Months Ended			% change		Six Months Ended		% change
Ireland business unit ($M except as indicated)	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Q2/16 vs. Q1/16	Q2/16 vs. Q2/15	Jun 30, 2016	Jun 30, 2015	2016 vs. 2015
Production								
Natural gas (mmcf/d)	47.26	33.90	-	39%	100%	40.58	-	100%
Total (boe/d)	7,877	5,650	-	39%	100%	6,763	-	100%
Activity								
Capital expenditures	2,172	3,076	20,267	(29%)	(89%)	5,248	33,222	(84%)
Financial results								
Sales	23,360	17,004	-	37%	100%	40,364	-	100%
Transportation	(1,574)	(1,639)	(1,648)	(4%)	(4%)	(3,213)	(3,341)	(4%)
Operating	(5,177)	(3,626)	-	43%	100%	(8,803)	-	100%
General and administration	(1,106)	(1,188)	(628)	(7%)	76%	(2,294)	(1,140)	101%
Fund flows from operations	15,503	10,551	(2,276)	47%	(781%)	26,054	(4,481)	(681%)
Netbacks ($/boe)								
Sales	32.59	33.07	-	(1%)	100%	32.79	-	100%
Transportation	(2.20)	(3.19)	-	(31%)	100%	(2.61)	-	100%
Operating	(7.22)	(7.05)	-	2%	100%	(7.15)	-	100%
General and administration	(1.54)	(2.31)	-	(33%)	100%	(1.86)	-	100%
Fund flows from operations netback	21.63	20.52	-	5%	100%	21.17	-	
Reference prices								
NBP ($/mmbtu)	5.78	5.97	8.42	(3%)	(31%)	5.88	8.71	(32%)
NBP (€/mmbtu)	3.97	3.94	6.19	1%	(36%)	3.96	6.32	(37%)

Production

- Natural gas began to flow from our Corrib gas project on December 30, 2015 and to date, well performance and facility runtimes have exceeded expectations.
- Production averaged 47 mmcf/d (7,877 boe/d) net to Vermilion during Q2 2016, an increase of 39% versus the prior quarter.
- Following the completion of previously planned recertification activities associated with the third party gas distribution pipeline network during the quarter, production volumes at Corrib reached full plant capacity of approximately 65 mmcf/d (10,900 boe/d), net to Vermilion at the end of Q2 2016.

Activity review

- As part of the recertification process, confirmatory inspection digs on the export sales pipeline were completed during Q2 2016, as well as some subsea inspections, maintenance and repairs on the subsea systems.
- Five of the six wells are currently on production, with the remaining well to be brought online in Q3 2016 following the conclusion of our offshore work program to lay a pipeline to the sixth well.

Sales

- The price of our natural gas in Ireland is based on the NBP index.

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 2016 transportation expense is slightly lower than Q1 2016 due to a favourable foreign exchange impact.
- Transportation expense for the three and six months ended June 30, 2016 is 4% lower versus the comparable periods in 2015, despite unfavourable foreign exchange impacts, due to a decrease in the ship or pay obligation.

Operating

- Operating expense increased on a dollar basis from Q1 2016 by 43% primarily due to the 39% increase in production.

General and administration

- General and administrative expense for the three and six months ended June 30, 2016 is higher versus the comparable periods in 2015 due to increased corporate allocations as a result of achieving our first two full quarters of production.

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 ($M except as indicated)	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Q2/16 vs. Q1/16	Q2/16 vs. Q2/15	Jun 30, 2016	Jun 30, 2015	2016 vs. 2015
Production								
Crude oil (bbls/d)	6,083	6,180	5,865	(2%)	4%	6,132	5,769	6%
Inventory (mbbls)								
Opening crude oil inventory	213	75	318			75	37	
Crude oil production	554	562	534			1,116	1,044	
Crude oil sales	(549)	(424)	(696)			(973)	(925)	
Closing crude oil inventory	218	213	156			218	156	
Activity								
Capital expenditures	39,939	7,827	6,468	410%	517%	47,766	12,923	270%
Gross wells drilled	2.00	-	-			2.00	-	
Net wells drilled	2.00	-	-			2.00	-	
Financial results								
Sales	33,713	19,935	56,204	69%	(40%)	53,648	75,488	(29%)
Operating	(12,100)	(7,491)	(18,083)	62%	(33%)	(19,591)	(23,969)	(18%)
General and administration	(1,788)	(1,325)	(1,141)	35%	57%	(3,113)	(2,595)	20%
PRRT	(144)	(128)	(3,371)	13%	(96%)	(272)	(5,725)	(95%)
Current income taxes	(1,126)	(777)	(5,134)	45%	(78%)	(1,903)	(5,711)	(67%)
Fund flows from operations	18,555	10,214	28,475	82%	(35%)	28,769	37,488	(23%)
Netbacks ($/boe)								
Sales	61.53	46.93	80.87	31%	(24%)	55.15	81.60	(32%)
Operating	(22.08)	(17.63)	(26.02)	25%	(15%)	(20.14)	(25.91)	(22%)
General and administration	(3.26)	(3.12)	(1.64)	4%	99%	(3.20)	(2.81)	14%
PRRT	(0.26)	(0.30)	(4.85)	(13%)	(95%)	(0.28)	(6.19)	(95%)
Current income taxes	(2.05)	(1.83)	(7.39)	12%	(72%)	(1.96)	(6.17)	(68%)
Fund flows from operations netback	33.88	24.05	40.97	41%	(17%)	29.57	40.52	(27%)
Reference prices								
Dated Brent (US $/bbl)	45.57	33.89	61.92	34%	(26%)	39.73	57.95	(31%)
Dated Brent ($/bbl)	58.72	46.59	76.12	26%	(23%)	52.91	71.59	(26%)

Production

- Q2 2016 production decreased 2% quarter-over-quarter and increased 4% year-over-year.
- 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

- Drilled a two-well sidetrack program in Q2 2016. One well was placed on production at the end of June 2016, with the second well placed on production in late July 2016.
- Other 2016 planned activity includes facilities enhancement, including work relating to platform life extension.

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Q2 2016 sales per boe increased versus Q1 2016, consistent with an increase in the Dated Brent reference price. This increase in price, combined with higher volumes sold, resulted in a 69% increase in sales.
- Sales per boe for the three and six months ended June 30, 2016 decreased versus the comparable periods in 2015 due to weaker crude oil pricing. For the three months ended June 30, 2016, this decline in price was coupled with lower volumes sold, resulting in a 40% decrease 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 dollar basis increased from Q1 2016, primarily due to the 29% increase in volumes sold, higher diesel costs and increased project activity.
- Year-over-year operating expense is down 33% and 18% for the three and six months ended June 30, 2016 versus the comparable periods in 2015. After adjusting for timing of sales, per unit cost decreases of 15% and 22% for the three and six month periods were realized through a continued focus on cost reduction initiatives, including reduced helicopter and vessel costs.

General and administration

- Fluctuation in general and administration expense for the three and six months ended June 30, 2016 versus the comparable periods in 2015 was largely a result of the timing of expenditures.

PRRT and corporate 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.
- For 2016, the effective tax rate for corporate income tax is expected to be between approximately 4% to 6% of pre-tax fund flows from operations and PRRT is expected to be between approximately 0% to 2% of pre-tax fund flows from operations. This is subject to change in response to commodity price fluctuations, the timing of capital expenditures and other eligible in-country adjustments.
- Current income taxes in Q2 2016 were higher compared to Q1 2016 and lower compared to Q2 2015 due to the respective change in sales.
- PPRT in Q2 2016 was relatively flat compared to Q1 2016 as increased sales were offset with the impact of 2016 capital expenditures in the calculation of PRRT. Q2 2016 PRRT was lower compared to Q2 2015 due to decreased sales.
- Q2 2016 year-to-date current income taxes and PRRT were lower versus the comparable period in 2015 as a result of decreased sales.

UNITED STATES BUSINESS UNIT

Overview
- Entered the United States in September 2014.
- Interests include approximately 97,100 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 ($M except as indicated)	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Q2/16 vs. Q1/16	Q2/16 vs. Q2/15	Jun 30, 2016	Jun 30, 2015	2016 vs. 2015
Production								
Crude oil (bbls/d)	458	368	123	24%	272%	413	138	199%
NGLs (bbls/d)	26	39	-	(33%)	100%	33	-	100%
Natural gas (mmcf/d)	0.20	0.26	-	(23%)	100%	0.23	-	100%
Total (boe/d)	518	450	123	15%	321%	484	138	251%
Activity								
Capital expenditures	1,636	5,101	2,744	(68%)	(40%)	6,737	3,381	99%
Acquisitions	5,432	115	-			5,547	-	
Gross wells drilled	-	-	1.00			-	1.00	
Net wells drilled	-	-	1.00			-	1.00	
Financial results								
Sales	2,207	1,233	677	79%	226%	3,440	1,349	155%
Royalties	(661)	(370)	(191)	79%	246%	(1,031)	(397)	160%
Operating	(302)	(279)	(110)	8%	175%	(581)	(325)	79%
General and administration	(697)	(1,132)	(963)	(38%)	(28%)	(1,829)	(2,043)	(10%)
Fund flows from operations	547	(548)	(587)	200%	193%	(1)	(1,416)	(100%)
Netbacks ($/boe)								
Sales	46.80	30.10	60.57	55%	(23%)	39.03	54.07	(28%)
Royalties	(14.02)	(9.03)	(17.08)	55%	(18%)	(11.70)	(15.92)	(27%)
Operating	(6.39)	(6.82)	(9.88)	(6%)	(35%)	(6.59)	(13.04)	(49%)
General and administration	(14.77)	(27.65)	(86.12)	(47%)	(83%)	(20.76)	(81.87)	(75%)
Fund flows from operations netback	11.62	(13.40)	(52.51)	187%	122%	(0.02)	(56.76)	(100%)
Realized prices								
Crude oil ($/bbl)	52.56	35.80	60.57	47%	(13%)	45.09	54.07	(17%)
NGLs ($/bbl)	3.25	4.81	-	(32%)	100%	4.18	-	100%
Natural gas ($/mmbtu)	0.37	0.67	-	(45%)	100%	0.54	-	100%
Total ($/boe)	46.80	30.10	60.57	55%	(23%)	39.03	54.07	(28%)
Reference prices								
WTI (US $/bbl)	45.59	33.45	57.94	36%	(21%)	39.52	53.29	(26%)
WTI ($/bbl)	58.75	45.99	71.23	28%	(18%)	52.63	65.83	(20%)
Henry Hub (US $/mmbtu)	1.95	2.09	2.64	(7%)	(26%)	2.02	2.81	(28%)
Henry Hub ($/mmbtu)	2.52	2.87	3.25	(12%)	(22%)	2.69	3.47	(22%)

Production
- Q2 2016 production increased 15% versus the prior quarter and over 300% versus the prior year due to production additions from our Seedy Draw well drilled in 2015, and Coyote Draw and Reed 17 wells completed in Q1 2016. The Coyote Draw well is currently producing 145 bbls/d in its fourth month of production. The Reed 17 well experienced a mechanical failure during the completion operation which resulted in only approximately 8% of the horizontal section being open to production. Despite only producing from one or two frac stages, the Reed 17 well is currently producing 40 bbls/d of oil in its third month of production.

Activity review
- In Q1 2016, we completed the two (2.0 net) wells drilled in the East Finn prospect in Q4 2015.

Sales
- The price of crude oil in the United States is directly linked to WTI, subject to market conditions in the United States.

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 of approximately 30% has remained consistent across all periods.

Operating

- The increase in operating expense for Q2 2016 as compared to Q1 2016 and Q2 2015 was primarily due to increasing production rates over these periods. On a per unit basis, expenses have decreased by 6% and 35% for these periods.
- On a year-over-year basis, full year per unit operating costs have decreased by 49% as a result of a continued focus on cost cutting initiatives and our drilling program (which resulted in a 251% increase in production).

General and administration

- General and administration expenses decreased versus Q1 2016 and Q2 2015 due to cost-cutting initiatives.
- On a year-over year basis cost-cutting initiatives have resulted in a 10% reduction in expenses.

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.

Financial review

CORPORATE ($M)	Three Months Ended Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Six Months Ended Jun 30, 2016	Jun 30, 2015
General and administration recovery	834	421	500	1,255	1,457
Current income taxes	(257)	(149)	(547)	(406)	(924)
Interest expense	(13,647)	(14,750)	(14,550)	(28,397)	(27,848)
Realized gain on derivatives	21,501	28,423	3,081	49,924	9,338
Realized foreign exchange gain (loss)	1,329	(652)	(2,740)	677	566
Realized other income	62	105	204	167	426
Fund flows from operations	9,822	13,398	(14,052)	23,220	(16,985)

General and administration

- The fluctuations in the recovery of general and administration costs for Q2 2016 versus all comparable periods is due to the timing of expenditures and salary 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 decrease in interest expense versus Q1 2016 and Q2 2015 is primarily due to the retiring of our 6.5% senior unsecured notes in February using funds from our revolving credit facility, which has a marginal rate of 3.4%.
- Interest expense of the six months ended June 30, 2016 was relatively unchanged as the aforementioned reduced interest expense from retiring our 6.5% senior unsecured notes was offset by higher average borrowings under our revolving credit facility.

Hedging

- The nature of our operations results in exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates. We monitor and, when appropriate, use derivative financial instruments to manage our exposure to these fluctuations. All transactions of this nature entered into are related to an underlying financial position or to future crude oil and natural gas production. We do not use derivative financial instruments for speculative purposes. We have elected not to designate any of our derivative financial instruments as accounting hedges and thus account for changes in fair value in net (loss) earnings at each reporting period. We have not obtained collateral or other security to support our financial derivatives as we review the creditworthiness of our counterparties prior to entering into derivative contracts.
- Our hedging philosophy is to hedge solely for the purposes of risk mitigation. Our approach is to hedge centrally to manage our global risk (typically with an outlook of 12 to 18 months) up to 50% of net of royalty volumes through a portfolio of forward collars, swaps, and physical fixed price arrangements. We currently have European gas contracts up to 30 months forward as an exception to our typical horizon.
- We believe that our hedging philosophy and approach increases the stability of revenues, cash flows, and future dividends while also assisting us in the execution of our capital and development plans.
- The realized gain in Q2 2016 related primarily to amounts received on our global natural gas and crude oil hedges.
- A listing of derivative positions as at June 30, 2016 is included in "Supplemental Table 2" of this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Three Months Ended							
($M except per share)	Jun 30, 2016	Mar 31, 2016	Dec 31, 2015	Sep 30, 2015	Jun 30, 2015	Mar 31, 2015	Dec 31, 2014	Sep 30, 2014
Petroleum and natural gas sales	212,855	177,385	234,319	245,051	264,331	195,885	306,073	344,688
Net (loss) earnings	(55,696)	(85,848)	(142,080)	(83,310)	6,813	1,275	58,642	53,903
Net (loss) earnings per share								
Basic	(0.48)	(0.76)	(1.28)	(0.76)	0.06	0.01	0.55	0.50
Diluted	(0.48)	(0.76)	(1.28)	(0.76)	0.06	0.01	0.54	0.50

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

	Three Months Ended			Six Months Ended	
	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Jun 30, 2016	Jun 30, 2015
Fund flows from operations	126,568	93,667	129,496	220,235	250,291
Equity based compensation	(13,267)	(20,837)	(17,886)	(34,104)	(36,926)
Unrealized (loss) gain on derivative instruments	(72,436)	9,054	4,105	(63,382)	(15,865)
Unrealized foreign exchange (loss) gain	(2,804)	1,570	5,031	(1,234)	186
Unrealized other expense	(20)	(87)	(204)	(107)	(465)
Accretion	(6,025)	(6,109)	(5,713)	(12,134)	(11,388)
Depletion and depreciation	(131,793)	(125,798)	(111,146)	(257,591)	(202,103)
Deferred tax	44,081	(22,546)	3,130	21,535	24,358
Impairment	-	(14,762)	-	(14,762)	-
Net (loss) earnings	(55,696)	(85,848)	6,813	(141,544)	8,088

The fluctuations in net (loss) earnings 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 and include: sales, royalties, operating expenses, transportation, general and administration expense, current tax expense, interest expense, realized gains and losses on derivative instruments, and realized foreign exchange gains and losses. 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 acquisitions or charges resulting from impairment or impairment recoveries.

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"). The expense is recognized over the vesting period based on the grant date fair value of awards, adjusted for the ultimate number of awards that actually vest as determined by the Company's achievement of performance conditions.

Equity based compensation decreased versus all comparable periods primarily due to a revision of vesting estimates. The decrease from Q1 2016 also resulted from the settlement of the employee bonus plan with equity in Q1 2016.

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, 2016, we recognized an unrealized loss on derivative instruments of $63.4 million, relating primarily to a loss on our global natural gas hedges. As at June 30, 2016, we have a net derivative asset position of $5.0 million.

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).

For the three months ended June 30, 2016, the Canadian dollar weakened slightly against the US dollar while remaining relatively unchanged against the Euro, resulting in an unrealized foreign exchange loss of $2.8 million. For the six months ended June 30, 2016, the Canadian dollar strengthened more significantly against the Euro than the US dollar, resulting in an unrealized foreign exchange loss of $1.2 million.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. Fluctuations in accretion expense are primarily the result of changes in discount rates applicable to the balance of asset retirement obligations and changes in the balance of asset retirement obligations, including the impact of additions resulting from drilling and acquisitions.

Q2 2016 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.

Depletion and depreciation on a per boe basis for Q2 2016 of $22.80 was relatively consistent as compared to $21.65 in Q1 2016 and $22.98 in Q2 2015. For the six months ended June 30, 2016, depletion and depreciation on a per boe basis of $22.23 was relatively consistent with $22.48 in the same period of 2015.

Deferred tax

Deferred tax expense (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.

Impairment

For the six months ended June 30, 2016, Vermilion recorded a non-cash impairment charge of $14.8 million in Ireland as a result of a decline in the price forecast for European natural gas.

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 excess 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, the 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 within forecasted fund flows from operations, which is continually monitored for revised forward price estimates, as well as by hedging additional European natural gas volumes to maintain a diversified commodity portfolio.

Long-term debt

Our long-term debt as at June 30, 2016 consists entirely of borrowings against our revolving credit facility. We redeemed the senior unsecured notes that came due on February 10, 2016 using funds drawn against the revolving credit facility.

The balances recognized on our balance sheet are as follows:

	As at	
($M)	Jun 30, 2016	Dec 31, 2015
Revolving credit facility	1,349,366	1,162,998
Senior unsecured notes	-	224,901
Long-term debt	1,349,366	1,387,899

Revolving Credit Facility

The following table outlines the current terms of our revolving credit facility:

	As at	
	Jun 30, 2016	Dec 31, 2015
Total facility amount	$2.0 billion	$2.0 billion
Amount drawn	$1.3 billion	$1.2 billion
Letters of credit outstanding	$24.0 million	$25.2 million
Facility maturity date	31-May-19	31-May-19

In addition, as at June 30, 2016, the revolving credit facility was subject to the following covenants:

		As at	
Financial covenant	Limit	Jun 30, 2016	Dec 31, 2015
Consolidated total debt to consolidated EBITDA	4.0	2.42	2.23
Consolidated total senior debt to total capitalization	55%	45%	36%

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

- Consolidated total debt: Includes all amounts classified as "Long-term debt", "Current portion of long-term debt", and "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.

Net debt

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

	As at	
($M)	Jun 30, 2016	Dec 31, 2015
Long-term debt	1,349,366	1,162,998
Current liabilities [1]	278,831	503,731
Current assets	(229,247)	(284,778)
Net debt	1,398,950	1,381,951
Ratio of net debt to annualized fund flows from operations	3.2	2.7

(1) Current liabilities at December 31, 2015 includes $224,901 relating to the current portion of long-term debt.

As at June 30, 2016, long term debt decreased to $1.35 billion (December 31, 2015 - $1.39 billion, including the current portion of long-term debt) as capital expenditures and cash dividends were funded through fund flows from operations. The decrease in long-term debt was offset by working capital changes, such that net debt increased from $1.38 billion at December 31, 2015 to $1.40 billion at June 30, 2016. Weaker commodity prices versus the prior period decreased fund flows from operations, resulting in the ratio of net debt to annualized fund flows from operations increasing from 2.7 to 3.2.

Shareholders' capital

During the six months ended June 30, 2016, we maintained monthly dividends at $0.215 per share and declared dividends which totalled $147.5 million.

The following table outlines our dividend payment history:

Date	Monthly dividend per unit or share
January 2003 to December 2007	$0.170
January 2008 to December 2012	$0.190
January 2013 to December 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.

As a further step to preserve our financial flexibility and conservatively exercise our access to capital, in February of 2015 we amended our existing dividend reinvestment plan to include a Premium Dividend™ Component. The Premium Dividend™ Component, when combined with our continuing Dividend Reinvestment Component, increases our access to the lowest cost sources of equity capital available. While the Premium Dividend™ results in a modest amount of equity issuance, we believe it represents the most prudent approach to preserving near-term balance sheet strength. We view implementation of a Premium Dividend™ as a short-term measure to maintain our financial flexibility while we continue to lower our unit costs and await further clarity on the direction of commodity prices. Both components of our program can be reduced or eliminated at the company's discretion, offering considerable flexibility. We will actively monitor our ongoing needs and manage our continued use of each component as circumstances dictate.

Although we expect to be able to maintain our current dividend, fund flows from operations may not be sufficient during this low commodity price environment to fund cash dividends, capital expenditures, and asset retirement obligations. We will evaluate our ability to finance any shortfalls 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, 2015	111,991	2,181,089
Shares issued for the DRIP[1]	2,640	98,506
Vesting of equity based awards	1,320	67,146
Share-settled dividends on vested equity based awards	87	3,242
Shares issued for equity based compensation	135	5,328
Balance as at June 30, 2016	116,173	2,355,311

(1) DRIP Refers to Vermilion's dividend reinvestment and Premium Dividend™ plans.

As at June 30, 2016, there were approximately 1.7 million VIP awards outstanding. As at August 4, 2016, there were approximately 116.6 million common shares issued and outstanding.

ASSET RETIREMENT OBLIGATIONS

As at June 30, 2016, asset retirement obligations were $329.1 million compared to $305.6 million as at December 31, 2015.

The increase in asset retirement obligations is largely attributable to an overall decrease in the discount rates applied to the abandonment obligations.

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, 2016.

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, 2015.

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, 2016. 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, 2015, 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.

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, 2016			Six Months Ended June 30, 2016			Three Months Ended June 30, 2015	Six Months Ended June 30, 2015
	Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	46.24	1.34	25.39	39.46	1.65	23.18	40.59	38.24
Royalties	(3.86)	0.06	(1.55)	(3.95)	(0.01)	(1.82)	(2.56)	(3.25)
Transportation	(2.23)	(0.16)	(1.55)	(2.27)	(0.16)	(1.56)	(1.99)	(1.90)
Operating	(7.29)	(1.06)	(6.77)	(7.30)	(1.26)	(7.44)	(9.58)	(9.19)
Operating netback	32.86	0.18	15.52	25.94	0.22	12.36	26.46	23.90
General and administration			(1.77)			(1.33)	(2.45)	(2.15)
Fund flows from operations netback			13.75			11.03	24.01	21.75
France								
Sales	58.19	1.58	57.82	50.60	1.62	50.32	71.96	68.52
Royalties	(6.19)	(0.39)	(6.16)	(6.14)	(0.35)	(6.11)	(5.84)	(5.68)
Transportation	(3.29)	-	(3.26)	(3.32)	-	(3.30)	(3.11)	(3.17)
Operating	(10.55)	(2.27)	(10.57)	(11.72)	(2.26)	(11.73)	(10.67)	(11.11)
Operating netback	38.16	(1.08)	37.83	29.42	(0.99)	29.18	52.34	48.56
General and administration			(4.44)			(4.32)	(4.30)	(4.84)
Other income			-			-	-	15.39
Current income taxes			(0.86)			(0.44)	(8.21)	(11.43)
Fund flows from operations netback			32.53			24.42	39.83	47.68
Netherlands								
Sales	45.05	5.27	31.77	38.10	5.41	32.55	47.63	48.13
Royalties	-	(0.09)	(0.52)	-	(0.09)	(0.54)	(2.58)	(2.11)
Operating	-	(0.96)	(5.71)	-	(1.10)	(6.53)	(10.78)	(10.66)
Operating netback	45.05	4.22	25.54	38.10	4.22	25.48	34.27	35.36
General and administration			(1.62)			(1.27)	(0.90)	(1.13)
Current income taxes			(4.32)			(3.47)	(4.67)	(4.49)
Fund flows from operations netback			19.60			20.74	28.70	29.74
Germany								
Sales	-	4.82	28.94	-	5.07	30.44	43.31	44.27
Royalties	-	(0.74)	(4.44)	-	(0.66)	(3.99)	(9.12)	(7.71)
Transportation	-	(0.81)	(4.84)	-	(0.70)	(4.22)	(5.05)	(4.29)
Operating	-	(1.92)	(11.55)	-	(1.85)	(11.11)	(5.60)	(6.78)
Operating netback	-	1.35	8.11	-	1.86	11.12	23.54	25.49
General and administration			(11.40)			(10.68)	(5.85)	(6.12)
Fund flows from operations netback			(3.29)			0.44	17.69	19.37
Ireland								
Sales	-	5.43	32.59	-	5.47	32.79	-	-
Transportation	-	(0.37)	(2.20)	-	(0.44)	(2.61)	-	-
Operating	-	(1.20)	(7.22)	-	(1.19)	(7.15)	-	-
Operating netback	-	3.86	23.17	-	3.84	23.03	-	-
General and administration			(1.54)			(1.86)	-	-
Fund flows from operations netback			21.63			21.17	-	-
Australia								
Sales	61.53	-	61.53	55.15	-	55.15	80.87	81.60
Operating	(22.08)	-	(22.08)	(20.14)	-	(20.14)	(26.02)	(25.91)
PRRT (1)	(0.26)	-	(0.26)	(0.28)	-	(0.28)	(4.85)	(6.19)
Operating netback	39.19	-	39.19	34.73	-	34.73	50.00	49.50
General and administration			(3.26)			(3.20)	(1.64)	(2.81)
Corporate income taxes			(2.05)			(1.96)	(7.39)	(6.17)
Fund flows from operations netback			33.88			29.57	40.97	40.52

Supplemental Table 1: Netbacks (Continued)

	Three Months Ended June 30, 2016			Six Months Ended June 30, 2016			Three Months Ended June 30, 2015	Six Months Ended June 30, 2015
	Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/bbl	Total $/boe
United States								
Sales	49.89	0.37	46.80	42.11	0.54	39.03	60.57	54.07
Royalties	(14.92)	(0.18)	(14.02)	(12.55)	(0.30)	(11.70)	(17.08)	(15.92)
Operating	(6.83)	-	(6.39)	(7.16)	-	(6.59)	(9.88)	(13.04)
Operating netback	28.14	0.19	26.39	22.40	0.24	20.74	33.61	25.11
General and administration			(14.77)			(20.76)	(86.12)	(81.87)
Fund flows from operations netback			11.62			(0.02)	(52.51)	(56.76)
Total Company								
Sales	53.90	3.53	36.83	46.63	3.65	33.67	54.65	51.19
Realized hedging gain	1.84	0.91	3.72	2.51	0.99	4.31	0.64	1.04
Royalties	(4.15)	(0.05)	(2.14)	(4.23)	(0.08)	(2.27)	(3.33)	(3.62)
Transportation	(2.15)	(0.22)	(1.71)	(2.24)	(0.22)	(1.75)	(2.25)	(2.27)
Operating	(11.44)	(1.13)	(9.02)	(11.27)	(1.25)	(9.30)	(12.12)	(11.40)
PRRT [1]	(0.05)	-	(0.02)	(0.05)	-	(0.02)	(0.70)	(0.64)
Operating netback	37.95	3.04	27.66	31.35	3.09	24.64	36.89	34.30
General and administration			(2.68)			(2.51)	(3.00)	(3.12)
Interest expense			(2.36)			(2.45)	(3.01)	(3.10)
Realized foreign exchange gain (loss)			0.23			0.06	(0.57)	0.06
Other income			0.01			0.01	0.04	3.58
Corporate income taxes [1]			(0.96)			(0.75)	(3.59)	(3.89)
Fund flows from operations netback			21.90			19.00	26.76	27.83

(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, 2016:

Crude Oil	Period	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
Dated Brent								
3-Way Collar [1]	Jul 2016 - Dec 2016	USD	3,000	48.68	3,000	60.00	3,000	39.33
Collar	May 2016 - Sept 2016	USD	250	41.50	500	49.85	-	-
Collar	Apr 2016 - Sept 2016	CAD	250	52.00	750	64.80	-	-
WTI								
Collar	Apr 2016 - Sept 2016	USD	750	40.50	2,000	50.45	-	-
Collar	May 2016 - Sept 2016	USD	750	41.17	1,500	50.67	-	-
Put [2]	May 2016 - Jul 2016	USD	1,000	40.00	-	-	-	-
Collar	Apr 2016 - Sept 2016	CAD	500	52.25	1,250	64.46	-	-

North American Gas	Period	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap Price / mmbtu	Additional Swap Volume (mmbtu/d) [3]
AECO									
Collar	Nov 2015 - Oct 2016	CAD	9,478	2.70	9,478	3.41	-	-	-
Collar	Jan 2016 - Dec 2016	CAD	9,478	2.66	9,478	3.47	-	-	-
Collar	Mar 2016 - Dec 2016	CAD	4,739	2.16	9,478	2.92	-	-	-
Collar	Apr 2016 - Oct 2016	CAD	4,739	2.43	4,739	2.96	-	-	-
Collar	Apr 2016 - Dec 2016	CAD	2,370	2.22	7,109	3.08	-	-	-
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	-	-	-
Swap	Apr 2016 - Oct 2016	CAD	-	-	-	-	4,739	2.73	4,739
Swap	Nov 2016 - Dec 2017	CAD	-	-	-	-	2,370	2.99	-
AECO Basis									
Swap	Jan 2017 - Dec 2017	USD	-	-	-	-	5,000	(0.75)	-
NYMEX									
Swap	Jan 2017 - Dec 2017	USD	-	-	-	-	5,000	3.00	-

(1) To fund the execution of the 3-way collar, Vermilion sold a swaption instrument. This instrument allows the counterparty, on August 31, 2016, to enter into a Dated Brent swap with Vermilion at a swap price of US$57.18 for 1,500 bbls/d during 2017.

(2) US$0.60/bbl funded cost

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

Supplemental Table 2: Hedges (Continued)

European Gas	Period	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap Price / mmbtu	Additional Swap Volume (mmbtu/d) [1]
NBP									
Collar	Apr 2016 - Mar 2017	GBP	2,500	4.00	2,500	4.77	-	-	-
Collar	Jul 2016 - Dec 2016	GBP	2,500	3.00	7,500	4.30	-	-	-
Collar	Oct 2016 - Mar 2017	GBP	2,500	3.30	5,000	3.72	-	-	-
Collar	Oct 2016 - Sept 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	-	-	-
Put	Apr 2016 - Sept 2016	GBP	2,500	4.00	-	-	-	-	-
Call	Oct 2016 - Mar 2017	GBP	-	-	2,500	4.90	-	-	-
Swap	Jul 2016 - Sept 2016	GBP	-	-	-	-	7,500	3.09	-
Swap	Jul 2016 - Dec 2016	GBP	-	-	-	-	2,500	3.81	-
Swap	Oct 2016 - Dec 2016	GBP	-	-	-	-	2,500	3.41	-
Swap	Jan 2017 - Dec 2017	GBP	-	-	-	-	2,500	4.22	2,500
Swap	Jul 2017 - Dec 2017	GBP	-	-	-	-	2,500	3.95	-
Swap	Jan 2018 - Dec 2018	GBP	-	-	-	-	2,500	4.04	5,000
Swap	Jul 2016 - Mar 2017	EUR	-	-	-	-	2,457	5.73	-
TTF									
Collar	Jan 2016 - Dec 2016	EUR	2,457	6.08	4,913	6.86	-	-	-
Collar	Apr 2016 - Dec 2016	EUR	12,284	5.89	14,740	6.55	-	-	-
Collar	Apr 2016 - Mar 2017	EUR	4,913	5.57	9,827	6.70	-	-	-
Collar	Jul 2016 - Dec 2016	EUR	2,457	5.28	2,457	5.93	-	-	-
Collar	Jul 2016 - Mar 2017	EUR	2,457	5.35	4,913	6.92	-	-	-
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 - Sept 2017	EUR	2,457	3.81	4,913	4.47	-	-	-
Collar	Jan 2018 - Dec 2018	EUR	4,913	4.40	4,913	5.31	-	-	-
Put	Apr 2016 - Sept 2016	EUR	2,457	5.50	-	-	-	-	-
Call	Oct 2016 - Mar 2017	EUR	-	-	2,457	6.36	-	-	-
Swap	Apr 2016 - Dec 2016	EUR	-	-	-	-	2,457	6.23	-
Swap	Jul 2016 - Jun 2018	EUR	-	-	-	-	2,559	5.89	-
Swap	Oct 2016 - Dec 2016	EUR	-	-	-	-	2,457	5.75	-
Swap	Jan 2017 - Dec 2017	EUR	-	-	-	-	2,457	5.32	2,457

[1] On the last business day of each month, the counterparty has the option to increase the contracted volumes for the

Fuel and Electricity	Period	Currency	Swap Volume (unit/d)	Average Swap Price/ unit
GasOil (bbl)				
Swap	Mar 2016 - Dec 2016	USD	125	42.55
AESO (mwh)				
Swap	Jan 2016 - Dec 2016	CAD	94	38.58
Swap	Jan 2017 - Dec 2017	CAD	65	33.47

Interest rate	Period	Currency	Notional Amount	Rate (%)
CDOR Swap	Sept 2015 - Sept 2019	CAD	100,000,000	1.00
CDOR Swap	Oct 2015 - Oct 2019	CAD	100,000,000	1.10

Supplemental Table 3: Capital Expenditures

By classification ($M)	Three Months Ended Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Six Months Ended Jun 30, 2016	Jun 30, 2015
Drilling and development	71,296	62,773	90,173	134,069	264,484
Exploration and evaluation	418	-	-	418	-
Capital expenditures	71,714	62,773	90,173	134,487	264,484
Property acquisition	8,550	870	480	9,420	515
Acquisitions	8,550	870	480	9,420	515

By category ($M)	Three Months Ended Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Six Months Ended Jun 30, 2016	Jun 30, 2015
Land	493	1,039	1,469	1,532	2,211
Seismic	1,323	6,268	1,723	7,591	3,216
Drilling and completion	36,542	27,853	31,976	64,395	114,319
Production equipment and facilities	35,612	6,238	43,957	41,850	118,712
Recompletions	768	3,598	9,288	4,366	16,403
Other	(3,024)	17,777	1,760	14,753	9,623
Capital expenditures	71,714	62,773	90,173	134,487	264,484
Acquisitions	8,550	870	480	9,420	515
Total capital expenditures and acquisitions	80,264	63,643	90,653	143,907	264,999

By country ($M)	Three Months Ended Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Six Months Ended Jun 30, 2016	Jun 30, 2015
Canada	6,415	30,526	22,265	36,941	137,149
France	12,772	13,463	16,793	26,235	50,907
Netherlands	8,566	2,996	18,885	11,562	23,218
Germany	592	539	3,231	1,131	4,199
Ireland	2,172	3,076	20,267	5,248	33,222
Australia	39,939	7,827	6,468	47,766	12,923
United States	7,068	5,216	2,744	12,284	3,381
Corporate	2,740	-	-	2,740	-
Total capital expenditures and acquisitions	80,264	63,643	90,653	143,907	264,999

Supplemental Table 4: Production

	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13
Canada												
Crude oil & condensate (bbls/d)	9,453	10,317	10,413	11,030	11,843	12,163	12,681	12,755	14,108	10,390	8,719	7,969
NGLs (bbls/d)	2,687	2,633	2,710	2,678	2,094	1,706	1,444	1,005	1,364	1,118	1,699	1,897
Natural gas (mmcf/d)	87.44	97.16	87.90	71.94	64.66	61.78	58.36	57.07	57.59	49.53	41.43	43.40
Total (boe/d)	26,713	29,141	27,773	25,698	24,713	24,165	23,851	23,272	25,070	19,763	17,322	17,099
% of consolidated	42%	44%	45%	47%	48%	48%	49%	47%	49%	42%	43%	41%
France												
Crude oil (bbls/d)	12,326	12,220	12,537	12,310	12,746	11,463	11,133	11,111	11,025	10,771	11,131	11,625
Natural gas (mmcf/d)	0.54	0.44	1.36	1.47	1.03	-	-	-	-	-	-	5.23
Total (boe/d)	12,416	12,293	12,763	12,555	12,917	11,463	11,133	11,111	11,025	10,771	11,131	12,496
% of consolidated	19%	19%	21%	22%	25%	23%	22%	22%	21%	23%	27%	30%
Netherlands												
Condensate (bbls/d)	96	114	110	109	112	63	81	63	96	69	62	48
Natural gas (mmcf/d)	49.18	53.40	56.34	53.56	32.43	36.41	31.35	38.07	40.35	43.15	37.53	28.78
Total (boe/d)	8,293	9,015	9,500	9,035	5,517	6,132	5,306	6,407	6,822	7,260	6,318	4,845
% of consolidated	13%	14%	16%	16%	11%	12%	11%	13%	13%	16%	15%	12%
Germany												
Natural gas (mmcf/d)	14.31	15.96	16.17	14.00	16.18	16.80	17.71	15.38	16.13	10.64	-	-
Total (boe/d)	2,385	2,660	2,695	2,333	2,696	2,801	2,952	2,563	2,689	1,773	-	-
% of consolidated	4%	4%	4%	4%	5%	6%	6%	5%	5%	4%	-	-
Ireland												
Natural gas (mmcf/d)	47.26	33.90	0.12	-	-	-	-	-	-	-	-	-
Total (boe/d)	7,877	5,650	20	-	-	-	-	-	-	-	-	-
% of consolidated	12%	9%	-	-	-	-	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	6,083	6,180	7,824	6,433	5,865	5,672	6,134	6,567	6,483	7,110	6,189	7,070
% of consolidated	9%	9%	13%	11%	11%	11%	12%	13%	12%	15%	15%	17%
United States												
Crude oil (bbls/d)	458	368	420	226	123	153	195	-	-	-	-	-
NGLs (bbls/d)	26	39	29	-	-	-	-	-	-	-	-	-
Natural gas (mmcf/d)	0.20	0.26	0.20	-	-	-	-	-	-	-	-	-
Total (boe/d)	518	450	483	226	123	153	195	-	-	-	-	-
% of consolidated	1%	1%	1%	-	-	-	-	-	-	-	-	-
Consolidated												
Crude oil, condensate & NGLs (bbls/d)	31,129	31,871	34,043	32,786	32,783	31,220	31,668	31,501	33,076	29,458	27,800	28,609
% of consolidated	48%	49%	56%	58%	63%	62%	64%	63%	63%	63%	68%	69%
Natural gas (mmcf/d)	198.93	201.11	162.09	140.97	114.29	115.00	107.42	110.52	114.08	103.32	78.96	77.41
% of consolidated	52%	51%	44%	42%	37%	38%	36%	37%	37%	37%	32%	31%
Total (boe/d)	64,285	65,389	61,058	56,280	51,831	50,386	49,571	49,920	52,089	46,677	40,960	41,510

Supplemental Table 4: Production (Continued)

	YTD 2016	2015	2014	2013	2012	2011
Canada						
Crude oil & condensate (bbls/d)	9,885	11,357	12,491	8,387	7,659	4,701
NGLs (bbls/d)	2,660	2,301	1,233	1,666	1,232	1,297
Natural gas (mmcf/d)	92.30	71.65	55.67	42.39	37.50	43.38
Total (boe/d)	27,928	25,598	23,001	17,117	15,142	13,227
% of consolidated	44%	46%	47%	41%	40%	38%
France						
Crude oil (bbls/d)	12,273	12,267	11,011	10,873	9,952	8,110
Natural gas (mmcf/d)	0.49	0.97	-	3.40	3.59	0.95
Total (boe/d)	12,354	12,429	11,011	11,440	10,550	8,269
% of consolidated	19%	23%	22%	28%	28%	23%
Netherlands						
Condensate (bbls/d)	105	99	77	64	67	58
Natural gas (mmcf/d)	51.29	44.76	38.20	35.42	34.11	32.88
Total (boe/d)	8,654	7,559	6,443	5,967	5,751	5,538
% of consolidated	13%	14%	13%	15%	15%	16%
Germany						
Natural gas (mmcf/d)	15.13	15.78	14.99	-	-	-
Total (boe/d)	2,522	2,630	2,498	-	-	-
% of consolidated	4%	5%	5%	-	-	-
Ireland						
Natural gas (mmcf/d)	40.58	0.03	-	-	-	-
Total (boe/d)	6,763	5	-	-	-	-
% of consolidated	10%	-	-	-	-	-
Australia						
Crude oil (bbls/d)	6,132	6,454	6,571	6,481	6,360	8,168
% of consolidated	9%	12%	13%	16%	17%	23%
United States						
Crude oil (bbls/d)	413	231	49	-	-	-
NGLs (bbls/d)	33	7	-	-	-	-
Natural gas (mmcf/d)	0.23	0.05	-	-	-	-
Total (boe/d)	484	247	49	-	-	-
% of consolidated	1%	-	-	-	-	-
Consolidated						
Crude oil, condensate & NGLs (bbls/d)	31,501	32,716	31,432	27,471	25,270	22,334
% of consolidated	49%	60%	63%	67%	67%	63%
Natural gas (mmcf/d)	200.02	133.24	108.85	81.21	75.20	77.21
% of consolidated	51%	40%	37%	33%	33%	37%
Total (boe/d)	64,837	54,922	49,573	41,005	37,803	35,202

Supplemental Table 5: Segmented Financial Results

	Three Months Ended June 30, 2016								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Drilling and development	5,619	12,772	8,566	592	2,172	39,939	1,636	-	71,296
Exploration and evaluation	-	-	-	-	-	-	-	418	418
Oil and gas sales to external customers	61,731	61,591	23,973	6,280	23,360	33,713	2,207	-	212,855
Royalties	(3,770)	(6,564)	(396)	(964)	-	-	(661)	-	(12,355)
Revenue from external customers	57,961	55,027	23,577	5,316	23,360	33,713	1,546	-	200,500
Transportation	(3,759)	(3,476)	-	(1,051)	(1,574)	-	-	-	(9,860)
Operating	(16,460)	(11,265)	(4,306)	(2,506)	(5,177)	(12,100)	(302)	-	(52,116)
General and administration	(4,305)	(4,734)	(1,223)	(2,474)	(1,106)	(1,788)	(697)	834	(15,493)
PRRT	-	-	-	-	-	(144)	-	-	(144)
Corporate income taxes	-	(921)	(3,260)	-	-	(1,126)	-	(257)	(5,564)
Interest expense	-	-	-	-	-	-	-	(13,647)	(13,647)
Realized gain on derivative instruments	-	-	-	-	-	-	-	21,501	21,501
Realized foreign exchange gain	-	-	-	-	-	-	-	1,329	1,329
Realized other income	-	-	-	-	-	-	-	62	62
Fund flows from operations	33,437	34,631	14,788	(715)	15,503	18,555	547	9,822	126,568

	Six Months Ended June 30, 2016								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Total assets	1,542,342	811,724	180,403	152,627	809,690	263,723	52,651	131,625	3,944,785
Drilling and development	35,390	26,235	11,562	1,131	5,248	47,766	6,737	-	134,069
Exploration and evaluation	-	-	-	-	-	-	-	418	418
Oil and gas sales to external customers	117,841	109,716	51,259	13,972	40,364	53,648	3,440	-	390,240
Royalties	(9,268)	(13,330)	(856)	(1,831)	-	-	(1,031)	-	(26,316)
Revenue from external customers	108,573	96,386	50,403	12,141	40,364	53,648	2,409	-	363,924
Transportation	(7,910)	(7,189)	-	(1,938)	(3,213)	-	-	-	(20,250)
Operating	(37,803)	(25,585)	(10,282)	(5,099)	(8,803)	(19,591)	(581)	-	(107,744)
General and administration	(6,781)	(9,410)	(1,996)	(4,902)	(2,294)	(3,113)	(1,829)	1,255	(29,070)
PRRT	-	-	-	-	-	(272)	-	-	(272)
Corporate income taxes	-	(955)	(5,460)	-	-	(1,903)	-	(406)	(8,724)
Interest expense	-	-	-	-	-	-	-	(28,397)	(28,397)
Realized gain on derivative instruments	-	-	-	-	-	-	-	49,924	49,924
Realized foreign exchange gain	-	-	-	-	-	-	-	677	677
Realized other income	-	-	-	-	-	-	-	167	167
Fund flows from operations	56,079	53,247	32,665	202	26,054	28,769	(1)	23,220	220,235

NON-GAAP FINANCIAL MEASURES

This MD&A includes references to certain financial measures which do not have standardized meanings. 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:

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.

Free cash flow: Represents fund flows from operations in excess of drilling and development and exploration and evaluation costs (collectively referred to as 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.

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

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 to assess the amount of cash distributed back to shareholders and re-invested in the business for maintaining production and organic growth.

Fund flows from operations (excluding Corrib) and Payout (excluding Corrib): Management excludes expenditures relating to the Corrib project in assessing fund flows from operations and payout in order to assess our ability to generate income and finance organic growth from our current producing assets. Beginning in Q1 2016, the Corrib project is considered a producing asset, and as such these financial measures are not applicable for the 2016 periods.

Diluted shares outstanding: Is 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.

Cash dividends per share: Represents cash dividends declared per share.

The following tables reconcile fund flows from operations excluding Corrib, net dividends, payout (and excluding Corrib), and diluted shares outstanding to their most directly comparable GAAP measures as presented in our financial statements:

The following tables reconcile fund flows from operations (and excluding Corrib), net dividends, payout (and excluding Corrib), and diluted shares outstanding to their most directly comparable GAAP measures as presented in our financial statements:

	Three Months Ended			Six Months Ended	
($M)	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Jun 30, 2016	Jun 30, 2015
Fund flows from operations	126,568	93,667	129,496	220,235	250,291
Expenses related to Corrib	N/A	N/A	2,276	N/A	4,481
Fund flows from operations (excluding Corrib)	N/A	N/A	131,772	N/A	254,772

	Three Months Ended			Six Months Ended	
($M)	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015	Jun 30, 2016	Jun 30, 2015
Dividends declared	74,662	72,847	70,976	147,509	140,366
Shares issued for the DRIP[1]	(50,516)	(47,990)	(42,301)	(98,506)	(63,679)
Net dividends	24,146	24,857	28,675	49,003	76,687
Drilling and development	71,296	62,773	90,173	134,069	264,484
Exploration and evaluation	418	-	-	418	-
Asset retirement obligations settled	2,200	2,024	1,218	4,224	4,325
Payout	98,060	89,654	120,066	187,714	345,496
Corrib drilling and development	N/A	N/A	(20,267)	N/A	(33,222)
Payout (excluding Corrib)	N/A	N/A	99,799	N/A	312,274

(1) DRIP Refers to Vermilion's dividend reinvestment and Premium Dividend™ plans.

	As at		
('000s of shares)	Jun 30, 2016	Mar 31, 2016	Jun 30, 2015
Shares outstanding	116,173	113,451	109,806
Potential shares issuable pursuant to the VIP	2,775	3,040	2,820
Diluted shares outstanding	118,948	116,491	112,626

CORPORATE INFORMATION

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 4, 5, 6]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Claudio A. Ghersinich [3, 6]
Executive Director, Carrera Investments Corp.
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

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

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 southeast Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
bcf	billion cubic feet
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
btu	British thermal units
CGU	Cash generating unit, the basis upon which Vermilion's assets are evaluated for potential impairments
DRIP	Dividend Reinvestment Plan
GJ	gigajoules
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mboe	thousand barrel of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmboe	million barrel of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
NBP	the reference price paid for natural gas in the United Kingdom, quoted in pence per therm, at the National Balancing Point Virtual Trading Point operated by National Grid. Our production in Ireland is priced with reference to NBP.
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 day-ahead price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services
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

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BANKERS

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Bank of Montreal

Canadian Imperial Bank of Commerce

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

HSBC Bank Canada

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian Branch

Alberta Treasury Branches

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

Union Bank, Canada Branch

JPMorgan Chase Bank, N.A., Toronto Branch

Canadian Western Bank

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EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

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