Q3 2016

THIRD QUARTER REPORT

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.

DEFINED PRODUCTION GROWTH | RELIABLE & GROWING DIVIDENDS

VERMILION ENERGY

Vermilion Energy Inc. ("Vermilion", "We", "Our", "Us" or the "Company") (TSX, NYSE: VET) is pleased to report operating and unaudited financial results for the three and nine months ended September 30, 2016.

HIGHLIGHTS

- Average production of 63,596 boe/d during Q3 2016 decreased by 1% compared to 64,285 boe/d in the prior quarter as lower production in Canada, France and the Netherlands was largely offset by higher production volumes in Ireland and Australia. During the third quarter, we restricted gas-weighted production in Canada and oil production in Australia in an effort to optimize pricing and manage to overall corporate production targets. Vermilion expects to achieve full year production at approximately the top-end of its 2016 guidance range of 62,500 to 63,500 boe/d, representing year-over-year production growth of approximately 16% (10% on a per share basis). Q3 2016 production increased 13% from 56,280 boe/d in Q3 2015, primarily due to production from Ireland, which was not on line in the year-earlier period.

- Fund flows from operations ("FFO") for Q3 2016 was $141.0 million ($1.21/basic share[(1)]), an increase of 11% quarter-over-quarter. This increase in FFO was primarily attributable to higher sales volumes in Australia, France and Ireland, and stronger AECO natural gas prices in Canada. Year-over-year, FFO increased by 9% compared to Q3 2015 as revenue from Ireland, coupled with lower operating expenses, taxes and royalties, more than offset lower commodity prices.

- Irish production averaged 59 mmcf/d (9,879 boe/d) net to Vermilion during Q3 2016, representing an increase of 25% versus the prior quarter. Production results continued to benefit from better-than-expected well deliverability and minimal downtime. Following the conclusion of a successful offshore work campaign that included laying a flowline to the P2 well, all six wells are now available for production.

- The two sidetrack wells drilled in Australia during Q2 2016 continued to demonstrate strong productive capability with combined production rates exceeding 4,500 bbls/d when utilized. Vermilion intends to produce these wells intermittently to meet corporate production targets while seeking to optimize ultimate recoveries and oil pricing. Following our successful 2015 and 2016 drilling campaigns, we do not expect to drill any additional wells in Australia until 2019.

- We completed our two-well drilling campaign in the Netherlands during the quarter. Langezwaag-3 encountered 17 meters of net pay in the Zechstein-2 carbonate formation. This well is being completed and is expected to be placed on production in November, at which time an in-line production test will be conducted. Andel-6ST encountered a large gas column of inadequate reservoir quality to justify completion. Potential remains to sidetrack this well to an updip location where higher quality gas zones may be encountered. The well has been suspended to allow us to reprocess seismic data to determine the viability of the potential updip target.

- Profitability Enhancement Plan ("PEP") initiatives continue to deliver cost savings across our business units. We estimate that full-year PEP savings related to capital, operating and administrative expenditures will exceed $60 million in 2016. Per-unit operating and G&A expenses are forecasted to decrease by 15% and 13% respectively year-over-year. As announced with our Q2 2016 results, identified cost savings allowed us to expand our 2016 capital program with only a modest change in our capital budget.

- We began proration of the Premium Dividend™ component of our Dividend Reinvestment Plan by 25% beginning with our October dividend payment. Eligible shareholders who have elected to participate in the Premium Dividend™ component are now receiving the 1.5% premium on 75% of their participating shares and the regular cash dividend on the remaining 25% of their shares. We expect to increase the proration factor by a further 25% beginning with the January 2017 dividend payment. Subject to unexpected changes in the commodity price outlook, we will continue to increase the proration during 2017, by the end of which there would be no further equity issuance under the Premium Dividend™ component of our Dividend Reinvestment Plan.

- We also intend to reduce the discount associated with our traditional Dividend Reinvestment Plan from 3% to 2%, beginning with the January 2017 dividend payment.

- Following the preliminary 2017/2018 exploration and development ("E&D") capital investment and production targets we disclosed in the prior quarter, our Board of Directors has formally approved an E&D capital budget of $295 million for 2017. We continue to target production of between 69,000 to 70,000 boe/d in 2017. The preliminary 2018 targets we announced last quarter remain unchanged at $335 million in E&D capital with corresponding production of 75,000 to 76,000 boe/d. Production at the top end of these ranges for 2017 and 2018 would deliver per share growth of approximately 6% for each year.

- We recently announced that Vermilion was one of only five oil and gas companies in the world, and the only oil and gas company in North America, to be awarded a position on CDP's Climate "A" List. CDP (formerly Carbon Disclosure Project) is a London-based not-for-profit organization that administers a global environmental disclosure system that assists in the measurement and management of corporate environmental impacts. To achieve Climate "A" List recognition, a company must receive consistently high scores across all of CDP's scoring dimensions. Only 193 companies globally achieved Climate "A" List recognition in 2016 and only three Canadian companies were awarded a position on this year's list.

(1) Non-GAAP Financial Measure. Please see the "Non-GAAP Financial Measures" section of Management's Discussion and Analysis.
™ denotes trademark of Canaccord Genuity Capital Corporation.

HIGHLIGHTS

	Three Months Ended			Nine Months Ended	
($M except as indicated) Financial	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Sep 30, 2016	Sep 30, 2015
Petroleum and natural gas sales	232,660	212,855	245,051	622,900	705,267
Fund flows from operations	140,974	126,568	129,435	361,209	379,726
Fund flows from operations ($/basic share) (1)	1.21	1.10	1.17	3.14	3.48
Fund flows from operations ($/diluted share) (1)	1.19	1.09	1.16	3.11	3.44
Net loss	(14,475)	(55,696)	(83,310)	(156,019)	(75,222)
Net loss ($/basic share)	(0.12)	(0.48)	(0.76)	(1.36)	(0.69)
Capital expenditures	41,039	71,714	93,381	175,526	357,865
Acquisitions	10,391	8,550	22,155	19,811	22,670
Asset retirement obligations settled	2,066	2,200	2,123	6,290	6,448
Cash dividends ($/share)	0.645	0.645	0.645	1.935	1.935
Dividends declared	75,465	74,662	71,244	222,974	211,610
% of fund flows from operations	54%	59%	55%	62%	56%
Net dividends (1)	24,553	24,146	26,654	73,556	103,341
% of fund flows from operations	17%	19%	21%	20%	27%
Payout (1)	67,658	98,060	122,158	255,372	467,654
% of fund flows from operations	48%	78%	94%	71%	123%
Net debt	1,343,923	1,398,950	1,363,043	1,343,923	1,363,043
Ratio of net debt to annualized fund flows from operations	2.4	2.8	2.6	2.8	2.7
Operational					
Production					
Crude oil and condensate (bbls/d)	27,842	28,416	30,108	28,483	30,106
NGLs (bbls/d)	2,478	2,713	2,678	2,621	2,163
Natural gas (mmcf/d)	199.66	198.93	140.97	199.90	123.51
Total (boe/d)	63,596	64,285	56,280	64,421	52,854
Average realized prices					
Crude oil, condensate and NGLs ($/bbl)	53.24	53.90	56.57	48.95	61.48
Natural gas ($/mcf)	3.98	3.53	5.36	3.76	5.18
Production mix (% of production)					
% priced with reference to WTI	19%	20%	24%	20%	26%
% priced with reference to AECO	20%	22%	22%	22%	21%
% priced with reference to TTF and NBP	32%	29%	20%	29%	18%
% priced with reference to Dated Brent	29%	29%	34%	29%	35%
Netbacks ($/boe)					
Operating netback	27.88	27.66	32.25	25.75	33.55
Fund flows from operations netback	23.25	21.90	24.58	20.46	26.64
Operating expenses	9.05	9.02	10.99	9.21	11.25
Average reference prices					
WTI (US $/bbl)	44.94	45.59	46.43	41.33	51.00
Edmonton Sweet index (US $/bbl)	42.06	42.51	43.01	38.11	46.64
Dated Brent (US $/bbl)	45.85	45.57	50.26	41.77	55.39
AECO ($/mmbtu)	2.32	1.40	2.90	1.85	2.77
NBP ($/mmbtu)	5.29	5.78	8.40	5.69	8.62
TTF ($/mmbtu)	5.43	5.61	8.48	5.58	8.52
Average foreign currency exchange rates					
CDN $/US $	1.31	1.29	1.31	1.32	1.26
CDN $/Euro	1.46	1.46	1.46	1.48	1.40
Share information ('000s)					
Shares outstanding - basic	117,386	116,173	110,818	117,386	110,818
Shares outstanding - diluted (1)	120,183	118,948	113,643	120,183	113,643
Weighted average shares outstanding - basic	116,814	115,366	110,293	114,975	109,052
Weighted average shares outstanding - diluted (1)	118,177	116,587	111,193	116,221	110,433

(1) The above table includes non-GAAP financial measures which may not be comparable to other companies. Please see the "NON-GAAP FINANCIAL MEASURES" section of Management's Discussion and Analysis.

DISCLAIMER

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

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

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

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

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

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

ABBREVIATIONS

$M	thousand dollars
$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO ‘C’ hub in 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
DRIP	Dividend Reinvestment Plan
GJ	gigajoules
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. 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 price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

MESSAGE TO SHAREHOLDERS

Oil prices have increased from the lows experienced during Q1 2016, but remain less than half of what they were in mid-2014 before the downturn started. While future prices are very difficult to accurately predict, it is possible that oversupply will persist and suppress prices for a considerable period. We intend to continue managing our company based on the current commodity strip, maintaining a low level of financial leverage, and keeping cash uses for dividends and exploration and development ("E&D") capital investment below our internal cash generation. At the same time, we are targeting continued growth in production per share.

Whether commodity prices are high or low, we follow a consistent strategy. This strategy is outlined in the current edition of our Corporate Presentation found on our website. We would like to review this strategy with you in the next few paragraphs.

Our capital markets model aims to deliver consistent growth-and-income to our shareholders. We are proud of our thirteen-year record of continuous monthly dividends. We have increased our dividend three times during this period and have never decreased it. Our goal is to also increase our production base on a per-share basis at organic growth rates that are appropriate to our asset base, and over the past five years this growth has accelerated. We intend to provide both the organic growth and income components of this model within our internally-generated cash flow.

Our operating, geographic and organizational models are integral to successfully delivering this ambitious growth-and-income capital markets model. We believe that the four model components represent an internally consistent strategy that differentiates Vermilion from our competitors.

Our operating model provides a framework to ensure that our asset composition supports our capital markets model. Vermilion's largely conventional and semi-conventional asset base delivers the high margins, low base decline rates and strong capital efficiencies which are required to deliver a self-funded growth-and-income model. These characteristics are paramount as we continue to develop the deep and diversified project inventory that supports our targeted organic growth rates for the long-term. We expect to further augment this organic inventory and growth through opportunistic and accretive acquisitions. Prospective acquisitions are subject to disciplined tests to ensure consistency with our operating and capital markets models. With a deep organic inventory already established, we are determined that any acquisitions will be accretive to the "organic part" of our company, and not dilutive of it.

Vermilion's geographic model is a significant differentiator for the Company. Since our first international acquisition in 1997, we have demonstrated our ability to successfully enter new jurisdictions and add assets to our portfolio that are aligned with our operating model. In addition, our geographic diversification provides flexibility to allocate capital to the highest return products and projects for a given economic environment, and creates the opportunity for outsized acquisition returns in certain jurisdictions. Our three regions (Europe, North America and Australia) all feature stable political, fiscal and regulatory regimes.

Our organizational model features a relatively-decentralized business unit structure to effectively manage our geographic diversity. Nonetheless, throughout our company, we maintain a consistent technical focus and emphasize the importance of our shared culture. While capital investment selection is managed as a portfolio at the corporate level, each of our business units (with their integrated engineering, geoscience, production operations and regulatory functions) is responsible for proposing a robust set of capital projects. Once a capital project slate has been selected at the corporate level, our business units are responsible for delivering their production, capital and operating expense targets.

Our self-funded growth-and-income model is fully aligned with the three priorities we have previously communicated to our shareholders. First, we intend to maintain a strong balance sheet. Second, we endeavor to protect our dividend. Third, we seek to deliver continued production growth on a per share basis. We believe that through disciplined execution of our strategy and adherence to these priorities, Vermilion can remain a core investment holding for our shareholders throughout the commodity price cycle.

Q3 2016 REVIEW

The third quarter was a strong one from both operational and financial perspectives. Production was relatively flat from the previous quarter despite a 43% reduction in E&D capital expenditures. Our cash uses for net dividends, E&D capital investment and abandonment expenditures represented 48% of fund flows. This resulted in over $70 million of excess cash generation after payout, which we used to fund minor bolt-on acquisitions in Canada and to reduce net debt by $55 million during the quarter.

Profitability Enhancement Plan ("PEP") initiatives continue to deliver cost savings across our business. As an expansion of our PEP program, all of Vermilion's employees were requested to submit an additional five cost-reducing ideas earlier this year. As a result of this widespread employee engagement, additional cost reductions have been achieved. We estimate that full-year PEP savings related to capital, operating and administrative expenditures will exceed $60 million in 2016. Per-unit operating and G&A expenses are forecasted to decrease by 15% and 13%, respectively, year-over-year. As announced with our Q2 2016 results, identified cost savings allowed us to expand our 2016 capital program with only a modest change in our capital budget.

We began proration of the Premium Dividend™ component of our Dividend Reinvestment Plan by 25% beginning with our October dividend payment. Eligible shareholders who have elected to participate in the Premium Dividend™ component are now receiving the 1.5% premium on 75% of their participating shares and the regular cash dividend on the remaining 25% of their shares. We expect to increase the proration factor by a further 25% beginning with the January 2017 dividend payment. Subject to unexpected changes in the commodity price outlook, we will continue to increase the proration during 2017, by the end of which there would be no further equity issuance under the Premium Dividend™ component of our Dividend Reinvestment Plan. We also intend to reduce the discount associated with our traditional Dividend Reinvestment Plan from 3% to 2%, beginning with the January 2017 dividend payment, subject to TSX approval.

Europe

Subsequent to the third quarter, we commenced our four (4.0 net) well Champotran drilling program in France. These wells will be completed and placed on production in early 2017. This program follows three consecutive years of highly successful Champotran drilling campaigns, during which we have drilled 14 wells with a 100% success rate. The wells drilled during the 2015 campaign continue to deliver strong production results with cumulative production to date approximately 17% greater than we had originally budgeted. Activity during the third quarter in France focused on well optimizations in the Neocomian fields. Our ongoing activities in the Neocomian have resulted in steady production growth since we acquired this asset in 2012. In Q3 2016, oil production levels in these fields reached the highest rate since June 1995, despite not having drilled any wells since the acquisition. We expect to drill our first wells in the Neocomian in 2017.

We completed our two-well drilling campaign in the Netherlands during the quarter. Langezwaag-3 encountered 17 meters of net pay in the Zechstein-2 carbonate formation. This well is being completed and is expected to be placed on production in November, at which time an in-line production test will be conducted. Andel-6ST encountered a large gas column of inadequate reservoir quality to justify completion. Potential remains to sidetrack this well to an updip location where higher quality gas zones may be encountered. The well has been suspended to allow us to reprocess seismic data to determine the viability of the potential updip target. As expected, production from our Diever-02 and Slootdorp-06/07 wells remained curtailed at the end of Q3 2016 pending final approval of our applications to increase production rates at the conclusion of the extended well test periods. We expect the extended well tests to be completed, and the related approvals to be received, during the first half of 2017.

In Germany, we commenced integration activities associated with the acquisition of assets from Engie E&P Deutschland GmbH that we announced in the prior quarter. As noted, this acquisition will provide Vermilion with our first operated position in the country and is expected to close by the end of the year. Germany remains a key area of interest for Vermilion as we advance our objective of developing a material business unit in the country.

Irish production averaged 59 mmcf/d (9,879 boe/d) net to Vermilion during Q3 2016, representing an increase of 25% versus the prior quarter. Production results continued to benefit from better than expected well deliverability and minimal downtime. Following the conclusion of a successful offshore work campaign that included laying a flowline to the P2 well, all six wells are now available for production.

North America

With our 2016 capital plan for North America predominately focused on preserving value through the drilling of operated land expiries and non-operated wells proposed by partners, third quarter capital activities in Canada were limited. We participated in four (1.2 net) condensate-rich Mannville wells drilled by partners but did not conduct any operated drilling. During the quarter, approximately 1,900 boe/d of natural gas weighted production remained voluntarily curtailed in response to low AECO prices. Although the majority of the curtailed volumes would have been economic at Q3 2016 AECO prices, the production is not required to meet our corporate targets, and we believe higher anticipated winter prices will deliver more cash flow from these wells. The majority of this curtailed production will be brought back online in Q1 2017.

During Q4 2016 we intend to drill or participate in seven (5.6 net) Mannville wells. With the exception of one (0.6 net) well, these wells are scheduled to be brought on production in early 2017. As announced in Q2, this activity is being largely funded by savings identified through PEP initiatives.

Australia

The two sidetrack wells drilled in Australia during Q2 2016 continued to demonstrate strong productive capability with combined production rates exceeding 4,500 bbls/d when utilized. Vermilion intends to produce these wells intermittently to meet corporate production targets while seeking to optimize ultimate recoveries and oil pricing. Following our successful 2015 and 2016 drilling campaigns, we do not expect to drill any additional wells in Australia until 2019. Late in the quarter, we commenced a planned 10-day maintenance shutdown. The scope of activities was completed as scheduled and production resumed on October 3, 2016. We also continued to advance our Wandoo Platforms Life Extension project during the quarter.

Sustainability

We recently announced that Vermilion was one of only five oil and gas companies in the world, and the only oil and gas company in North America, to be awarded a position on CDP's Climate "A" List. CDP (formerly Carbon Disclosure Project) is a London-based not-for-profit organization that administers a global environmental disclosure system that assists in the measurement and management of corporate environmental impacts. To achieve Climate "A" List recognition, a company must receive consistently high scores across all of CDP's scoring dimensions. Only 193 companies globally achieved Climate "A" List recognition in 2016, and only three Canadian companies were awarded a position on this year's list.

Vermilion has voluntarily reported emissions data to CDP for each year since 2012. We firmly believe in the importance of measuring and understanding our current environmental impact. This assists our effort to identify and realize opportunities to operate in an even more environmentally and socially sustainable manner in the future.

We also recently released our third annual Sustainability Report which details our efforts to generate environmental, social, and economic benefits for all stakeholders. The report describes our approach to sustainability in our operations, and details our progress and challenges in this regard. We are committed to providing increasingly complete information and objective assessment of our performance in this area on an annual basis. Furthermore, we believe the integration of sustainability principles into our business strategy increases shareholder returns and reduces long-term risks to our business model. Our 2016 Sustainability Report is available on our corporate website at www.vermilionenergy.com/sustainability.

2017 BUDGET

Following the preliminary 2017/2018 E&D capital investment and production targets we disclosed in the prior quarter, our Board of Directors has formally approved an E&D capital budget of $295 million for 2017. We continue to target production of between 69,000 to 70,000 boe/d in 2017. This budget funds development of high-return projects including our condensate-rich Mannville projects in Canada, continued drilling in France, favorably-priced European natural gas projects in the Netherlands, and our emerging Turner Sands play in the United States. The preliminary targets we announced last quarter for 2018 are unchanged with E&D capital investment of $335 million and corresponding production of 75,000 to 76,000 boe/d. Production at the top end of these ranges would represent per share growth of approximately 6% for both years, within our targeted range of 5-7% annual per share production growth.

Our 2017 E&D budget represents the third year of significantly lower capital expenditures since the current commodity price downturn started in 2014. Despite this reduced spending level, we expect to continue delivering strong per share production growth. Our geographic and commodity diversification allow for a high return capital program even in depressed commodity markets, and provides the flexibility to respond to changes in individual commodity markets as prices recover.

At current strip prices, Vermilion expects to fully fund 2017 E&D expenditures and cash dividends from fund flows from operations, with surplus cash generation primarily directed to debt reduction. We maintain the operational flexibility to reduce our 2017 E&D program if commodity prices unexpectedly weaken. Should capital availability increase during the year as a result of a meaningful and sustainable improvement in commodity prices, we do have the capability to increase E&D investment levels. However, we would expect any potential increase to be modest and fully funded by internal cash generation under the prevailing commodity strip.

Europe

Our 2017 E&D budget for the Netherlands of $46 million represents an increase of 92% from our forecasted 2016 investment of $24 million. We anticipate drilling three (1.5 net) exploration wells and one (0.5 net) development well, as compared to our 2016 activity of two (0.9 net) exploration wells. Included in our budget for the Netherlands is a $10 million seismic program in our Akkrum and Zuid Friesland concessions and a major turnaround at our Garijp Treatment Centre.

In France, we have set a 2017 E&D budget of $69 million, representing a 5% increase from our 2016 forecast of $66 million. We intend to complete and tie-in the four (4.0 net) Champotran wells being drilled in Q4 2016 in early 2017 and continue our ongoing program of workovers and optimizations. We also expect to drill our first four (4.0 net) wells in the Neocomian fields in the Paris Basin. The Neocomian fields were acquired by Vermilion in 2012 and since then, we have increased production by approximately 50% through workovers and artificial lift optimizations.

Our 2017 German capital program of $18 million represents a significant increase from the $4 million forecast for 2016. Vermilion will assume operatorship for the drilling phase of the Burgmoor Z5 development well (0.25 net) in the Dümmersee-Uchte area, where we are a member of a four-partner consortium. Completion, tie-in and associated production from this well is expected in mid-2018. We also expect to invest in optimizations and other well work on the acquired Engie assets. Lastly, we will continue to advance our permitting, studies and other activities associated with the farm-in agreement we signed in mid-2015.

Following the achievement of first gas at Corrib on December 30, 2015, and the tie-in of the P2 well during Q3 2016, a low level of capital investment is expected in 2017.

North America

We expect to invest approximately $108 million in E&D activities in Canada in 2017, representing an increase of 83% from the $59 million forecasted for 2016. Our Canadian assets provide significant flexibility to ramp activity levels up or down in response to the prevailing commodity price environment, with a diversified project inventory that provides exposure to oil, condensate and natural gas opportunities.

Our Canadian investment program is significantly oil-weighted. In 2017, we expect to drill or participate in 19 (11.3 net) Mannville wells as well as complete 2.5 net wells and tie-in 6.0 net wells drilled in 2016. Our Ellerslie condensate-focused Mannville program provides particularly attractive economics in the current commodity price environment. Our Cardium light oil program includes nine (6.0 net) wells, with five (5.0 net) of those wells being operated. We intend to drill or participate in 13 (11.3 net) Midale light oil wells in our Southeast Saskatchewan light oil play, as well as to complete and tie-in the four operated wells we drilled earlier in 2016.

In the United States, we expect to drill and complete three (3.0 net) wells targeting the light oil Turner Sand in the Powder River Basin of Wyoming.

Australia

Following our successful 2015 and 2016 drilling campaigns, we do not expect to drill any additional wells in Australia until 2019. Our 2017 E&D budget of $30 million for Australia will focus on adding value through asset optimization and targeted proactive maintenance. Approximately 50% of our budgeted E&D capital program for 2017 is allocated to further improving and debottlenecking our fluid handling capability on the Wandoo B platform. Once completed, we expect that this infrastructure enhancement will allow us to increase oil production on the platform by 600 to 700 bbls/d to help offset natural decline and maintain steady production. The balance of our budget will support a refurbishment campaign that will further extend the life of our Australian assets while reducing future repair and maintenance expenditures.

Capital Expenditures by Country

Country	2017 Budget* ($MM)	2016 Estimate ($MM)	2017 vs. 2016 % Change	2017 Net Wells	2016 Net Wells
Canada	108	59	83%	28.6	16.2
France	69	66	5%	4.0	4.0
Netherlands	46	24	92%	2.0	0.9
Germany	18	4	350%	0.3	-
Australia	30	63	(52%)	-	2.0
USA	16	13	23%	3.0	-
Ireland	2	9	(78%)	-	-
Central and Eastern Europe	6	2	200%	-	-
Total E&D Capital Expenditures	295	240	23%	37.9	23.1

Development Capital by Category

Category	2017 Budget* ($MM)	2016 Estimate ($MM)	2017 vs. 2016 % Change
Drilling, completion, new well equipment and tie-in, workovers and recompletions	175	160	9%
Production equipment and facilities	70	50	40%
Seismic, studies, land and other	50	30	67%
Total E&D Capital Expenditures	295	240	23%

* 2017 Budget reflects foreign exchange assumptions of USD/CAD 1.32, CAD/EUR 1.48 and CAD/AUD 0.99.

Commodity Hedging

Vermilion hedges to manage commodity price exposures and increase the stability of cash flows providing additional certainty with regards to the execution of our capital program. We currently have 33% of our expected net-of-royalty production hedged for 2017, including 50% of anticipated European natural gas volumes and 49% of anticipated North American gas volumes. We will continue to hedge into the 2017 and 2018 periods as suitable opportunities arise.

For additional information on our current hedge position, please visit our website at http://www.vermilionenergy.com/ir/hedging.cfm.

(signed "Anthony Marino")

Anthony Marino
President & Chief Executive Officer
October 31, 2016

TM denotes trademark of Canaccord Genuity Capital Corporation.

ORGANIZATIONAL UPDATE

Vermilion is pleased to announce the appointment of Mr. Robert Michaleski to our Board of Directors effective October 3, 2016.

Mr. Michaleski brings over 30 years of experience in various senior management and executive capacities at Pembina Pipeline Corporation. He has overseen Pembina’s transformation from an Alberta-based oil pipeline company into one of North America’s leading integrated energy transportation and midstream services companies. When he took over leadership, Pembina’s total enterprise value was $450 million and, when he retired in 2013, it was over $12.5 billion. He was Chief Executive Officer from 2000 to 2013 and also President from 2000 to 2012. He was Vice President and Chief Financial Officer from 1997 to 2000, Vice President of Finance from 1992 to 1997, Controller from 1980 to 1992, and Manager of Internal Audit from 1978 to 1980. He has been a Director of Pembina since 2000, a Director of Essential Energy Services Ltd. since 2012, and a Director of Coril Holdings Ltd. since 2003. A proud supporter of the community, Mr. Michaleski provides his leadership to United Way of Calgary and Area serving as co-chair of the General Oil and Gas Division since 2010 and a Director since 2013. Mr. Michaleski holds a Bachelor of Commerce (Honours) Degree from the University of Manitoba. He received his Chartered Accountant designation in 1978. He is a member of the Institute of Corporate Directors.

We look forward to the contributions that Mr. Michaleski will make to our Board of Directors and to the ongoing success of Vermilion.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A"), dated October 28, 2016, of Vermilion Energy Inc.'s ("Vermilion", "We", "Our", "Us" or the "Company") operating and financial results as at and for the three and nine months ended September 30, 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 nine months ended September 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 nine months ended September 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:

(1) 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.

(2) 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.

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.

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.

We released our 2017 capital budget and related guidance concurrent with the release of our Q3 2016 results.

The following table summarizes our 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
2017 Guidance			
2017 Guidance	October 31, 2016	295	69,000 to 70,000

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change		Nine Months Ended		% change
	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Crude oil and condensate (bbls/d)	27,842	28,416	30,108	(2%)	(8%)	28,483	30,106	(5%)
NGLs (bbls/d)	2,478	2,713	2,678	(9%)	(7%)	2,621	2,163	21%
Natural gas (mmcf/d)	199.66	198.93	140.97	-	42%	199.90	123.51	62%
Total (boe/d)	63,596	64,285	56,280	(1%)	13%	64,421	52,854	22%
Build (draw) in inventory (mbbls)	(209)	70	(85)			3	177	
Financial metrics								
Fund flows from operations ($M)	140,974	126,568	129,435	11%	9%	361,209	379,726	(5%)
Per share ($/basic share)	1.21	1.10	1.17	10%	3%	3.14	3.48	(10%)
Net loss	(14,475)	(55,696)	(83,310)	(74%)	(83%)	(156,019)	(75,222)	107%
Per share ($/basic share)	(0.12)	(0.48)	(0.76)	(75%)	(84%)	(1.36)	(0.69)	97%
Net debt ($M)	1,343,923	1,398,950	1,363,043	(4%)	(1%)	1,343,923	1,363,043	(1%)
Cash dividends ($/share)	0.645	0.645	0.645	-	-	1.935	1.935	-
Activity								
Capital expenditures ($M)	41,039	71,714	93,381	(43%)	(56%)	175,526	357,865	(51%)
Acquisitions ($M)	10,391	8,550	22,155	22%	(53%)	19,811	22,670	(13%)
Gross wells drilled	6.00	4.00	11.00			22.00	45.00	
Net wells drilled	2.08	3.14	6.91			13.48	30.56	

Operational review

- Achieved consolidated average production of 63,596 boe/d in Q3 2016, a 1% decrease from Q2 2016 due to lower production in Canada, France, and the Netherlands, which was largely offset by increased production in Ireland and Australia.
- Increased consolidated average production for the three and nine months ended September 30, 2016, by 13% and 22%, versus the comparable periods in 2015. These increases were primarily due to the addition of Corrib production in Ireland. The increase for the nine months ended September 30, 2016, was also due to production increases in Canada and the Netherlands.
- Executed capital expenditures totaling $41.0 million, primarily in France, Australia, Canada, and the Netherlands. In France, capital expenditures of $11.1 million were incurred related to a number of workover and optimization programs in the Aquitaine and Paris basins. In Australia, capital expenditures of $6.9 million were incurred as we continued to advance our Wandoo Platforms Life Extension project during the quarter. Capital expenditures of $10.4 million and $6.4 million were incurred in Canada and the Netherlands, respectively, related largely to drilling activity.

Financial review

Net loss

- The net loss for Q3 2016 was $14.5 million ($0.12/basic share), compared to a net loss of $55.7 million ($0.48/basic share) in Q2 2016. The decrease in the net loss was primarily attributable to higher revenues as a result of higher sales volumes.
- The net loss for Q3 2016 was $14.5 million, compared to a net loss of $83.3 million in Q3 2015. The change was a result of the absence of a non-cash impairment charge recognized in Q3 2015, partially offset by lower unrealized gains on derivative instruments.
- The net loss for the nine months ended September 30, 2016 of $156.0 million is compared to a net loss of $75.2 million for the 2015 period. The change was a result of lower commodity prices 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 $141.0 million during Q3 2016, an increase of 11% from Q2 2016. This quarter-over-quarter increase was primarily attributable to higher sales volumes in Australia, France, and Ireland, as well as stronger AECO natural gas prices in Canada.
- Fund flows from operations increased by 9% in Q3 2016 as compared to Q3 2015 as revenue from Ireland, coupled with lower operating expenses, taxes and royalties, more than offset lower commodity prices. For the nine months ended September 30, 2016, fund flows from operations decreased by 5% as compared to the corresponding period in 2015, largely due to lower commodity prices, partially offset by higher production volumes in Australia and Ireland and an 18% reduction in per unit operating expenses.

Net debt

- Net debt decreased to $1.34 billion from $1.40 billion at June 30, 2016 as fund flows from operations generated in excess of capital expenditures, abandonment expenditures, net dividends, and minor acquisitions was used to reduce net debt.

Dividends

- Declared dividends of $0.215 per common share per month during the third quarter of 2016, totalling $1.935 per common share for the nine months ended September 30, 2016.

COMMODITY PRICES

	Three Months Ended			% change		Nine Months Ended		% change
	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Average reference prices								
Crude oil								
WTI (US $/bbl)	44.94	45.59	46.43	(1%)	(3%)	41.33	51.00	(19%)
Edmonton Sweet index (US $/bbl)	42.06	42.51	43.01	(1%)	(2%)	38.11	46.64	(18%)
Dated Brent (US $/bbl)	45.85	45.57	50.26	1%	(9%)	41.77	55.39	(25%)
Natural gas								
AECO ($/mmbtu)	2.32	1.40	2.90	66%	(20%)	1.85	2.77	(33%)
TTF ($/mmbtu)	5.43	5.61	8.48	(3%)	(36%)	5.58	8.52	(35%)
TTF (€/mmbtu)	3.73	3.86	5.82	(3%)	(36%)	3.78	6.07	(38%)
NBP ($/mmbtu)	5.29	5.78	8.40	(8%)	(37%)	5.69	8.62	(34%)
NBP (€/mmbtu)	3.63	3.97	5.77	(9%)	(37%)	3.85	6.14	(37%)
Henry Hub ($/mmbtu)	3.67	2.52	3.62	46%	1%	3.03	3.52	(14%)
Henry Hub (US $/mmbtu)	2.81	1.95	2.77	44%	1%	2.29	2.80	(18%)
Average foreign currency exchange rates								
CDN $/US $	1.31	1.29	1.31	2%	-	1.32	1.26	5%
CDN $/Euro	1.46	1.46	1.46	-	-	1.48	1.40	6%
Average realized prices ($/boe)								
Canada	28.75	25.39	32.78	13%	(12%)	24.89	36.34	(32%)
France	55.88	57.82	60.96	(3%)	(8%)	52.26	65.66	(20%)
Netherlands	31.80	31.77	49.42	-	(36%)	32.31	48.70	(34%)
Germany	30.47	28.94	44.36	5%	(31%)	30.45	44.30	(31%)
Ireland	28.68	32.59	-	(12%)	100%	31.04	-	100%
Australia	60.61	61.53	68.20	(1%)	(11%)	57.51	76.46	(25%)
United States	44.53	46.80	51.60	(5%)	(14%)	40.78	52.95	(23%)
Consolidated	38.40	36.83	46.56	4%	(18%)	35.29	49.48	(29%)
Production mix (% of production)								
% priced with reference to WTI	19%	20%	24%			20%	26%	
% priced with reference to AECO	20%	22%	22%			22%	21%	
% priced with reference to TTF and NBP	32%	29%	20%			29%	18%	
% priced with reference to Dated Brent	29%	29%	34%			29%	35%	

- Q3 2016 was a volatile quarter for oil benchmarks that ended with prices largely unchanged quarter-over-quarter. The impact of continued reductions in non-OPEC supply and above-trend demand growth was offset by record high output from OPEC, including the partial return of Libyan and Nigerian volumes.
- Natural gas prices at AECO increased by 66% as compared to Q2 2016, as the warmer-than-normal summer in the United States boosted demand for Canadian natural gas. Despite the rise in AECO prices over Q2 2016, AECO decreased by 20% as compared to Q3 2015 as a result of high storage levels and strong Canadian production.
- Ample supply and coal-to-gas switching economics resulted in European natural gas price declines quarter-over-quarter, with TTF down 3% and NBP down 8% in Q3 2016 versus Q2 2016.
- In Q3 2016, the Canadian dollar was relatively consistent versus both the US dollar and Euro compared to Q2 2016 and Q3 2015, respectively.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Nine Months Ended			
	Sep 30, 2016		Jun 30, 2016		Sep 30, 2015		Sep 30, 2016		Sep 30, 2015	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	232,660	38.40	212,855	36.83	245,051	46.56	622,900	35.29	705,267	49.48
Royalties	(12,969)	(2.14)	(12,355)	(2.14)	(17,100)	(3.25)	(39,285)	(2.23)	(49,635)	(3.48)
Petroleum and natural gas revenues	219,691	36.26	200,500	34.69	227,951	43.31	583,615	33.06	655,632	46.00
Transportation	(9,696)	(1.60)	(9,860)	(1.71)	(11,090)	(2.11)	(29,946)	(1.70)	(31,513)	(2.21)
Operating	(54,825)	(9.05)	(52,116)	(9.02)	(57,826)	(10.99)	(162,569)	(9.21)	(160,293)	(11.25)
General and administration	(12,295)	(2.03)	(15,493)	(2.68)	(13,088)	(2.49)	(41,365)	(2.34)	(41,153)	(2.89)
PRRT	272	0.04	(144)	(0.02)	(99)	(0.02)	-	-	(5,824)	(0.41)
Corporate income taxes	(3,546)	(0.59)	(5,564)	(0.96)	(12,383)	(2.35)	(12,270)	(0.70)	(47,350)	(3.32)
Interest expense	(14,150)	(2.34)	(13,647)	(2.36)	(15,420)	(2.93)	(42,547)	(2.41)	(43,268)	(3.04)
Realized gain on derivative instruments	13,532	2.23	21,501	3.72	10,854	2.06	63,456	3.60	20,192	1.42
Realized foreign exchange gain	2,073	0.34	1,329	0.23	309	0.06	2,750	0.16	875	0.06
Realized other (expense) income	(82)	(0.01)	62	0.01	227	0.04	85	-	32,428	2.28
Fund flows from operations	140,974	23.25	126,568	21.90	129,435	24.58	361,209	20.46	379,726	26.64

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

($M)	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	2016 vs. 2015
Fund flows from operations – Comparative period	126,568	129,435	379,726
Sales volume variance:			
Canada	(3,556)	(8,195)	(5,807)
France	6,010	(4,819)	2,596
Netherlands	(503)	(4,602)	20,498
Germany	156	345	(1,341)
Ireland	2,705	26,065	66,429
Australia	11,803	11,125	16,121
United States	(304)	746	2,815
Pricing variance on sales volumes:			
WTI	(1,290)	(1,334)	(34,348)
AECO	7,498	(3,499)	(24,178)
Dated Brent	(3,061)	(12,127)	(78,121)
TTF and NBP	347	(16,096)	(47,031)
Changes in:			
Royalties	(614)	4,131	10,350
Transportation	164	1,394	1,567
Operating	(2,709)	3,001	(2,276)
General and administration	3,198	793	(212)
PRRT	416	371	5,824
Corporate income taxes	2,018	8,837	35,080
Interest	(503)	1,270	721
Realized derivatives	(7,969)	2,678	43,264
Realized foreign exchange	744	1,764	1,875
Realized other income	(144)	(309)	(32,343)
Fund flows from operations – Current period	140,974	140,974	361,209

Generated fund flows from operations of $141.0 million during Q3 2016, an increase of 11% from Q2 2016. This quarter-over-quarter increase was primarily attributable to higher sales volumes in Australia, France, and Ireland, as well as stronger AECO natural gas prices in Canada.

Fund flows from operations increased by 9% in Q3 2016 as compared to Q3 2015 as revenue from Ireland, coupled with lower operating expenses, taxes and royalties, more than offset lower commodity prices. For the nine months ended September 30, 2016, fund flows from operations decreased by 5% as compared to the corresponding period in 2015, largely due to lower commodity prices, partially offset by higher production volumes in Australia and Ireland and an 18% reduction in per unit operating expenses.

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

CANADA BUSINESS UNIT

Overview

- Production and assets focused in West Pembina near Drayton Valley, Alberta and Northgate in southeast Saskatchewan.
- Potential for three significant resource plays sharing the same surface infrastructure in the West Pembina region in Alberta:
  - Cardium light oil (1,800m depth) – in development phase
  - Mannville condensate-rich gas (2,400 – 2,700m depth) – in development phase
  - Duvernay condensate-rich gas (3,200 – 3,400m depth) – in appraisal phase with no investment at present
- Canadian cash flows are fully tax-sheltered for the foreseeable future.

Operational and financial review

	Three Months Ended			% change		Nine Months Ended		% change
Canada business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Crude oil and condensate (bbls/d)	8,984	9,453	11,030	(5%)	(19%)	9,582	11,674	(18%)
NGLs (bbls/d)	2,448	2,687	2,678	(9%)	(9%)	2,589	2,163	20%
Natural gas (mmcf/d)	77.62	87.44	71.94	(11%)	8%	87.37	66.16	32%
Total (boe/d)	24,368	26,713	25,698	(9%)	(5%)	26,732	24,864	8%
Production mix (% of total)								
Crude oil and condensate	37%	35%	43%			36%	47%	
NGLs	10%	10%	10%			10%	9%	
Natural gas	53%	55%	47%			54%	44%	
Activity								
Capital expenditures	10,421	5,619	37,224	85%	(72%)	45,811	173,954	(74%)
Acquisitions	10,380	796	8,062			11,931	8,481	
Gross wells drilled	4.00	2.00	11.00			18.00	37.00	
Net wells drilled	1.20	1.14	6.91			10.60	23.45	
Financial results								
Sales	64,453	61,731	77,493	4%	(17%)	182,294	246,661	(26%)
Royalties	(4,817)	(3,770)	(6,638)	28%	(27%)	(14,085)	(20,998)	(33%)
Transportation	(3,978)	(3,759)	(4,131)	6%	(4%)	(11,888)	(12,542)	(5%)
Operating	(15,579)	(16,460)	(23,877)	(5%)	(35%)	(53,382)	(64,510)	(17%)
General and administration	(3,010)	(4,305)	(3,694)	(30%)	(19%)	(9,791)	(13,219)	(26%)
Fund flows from operations	37,069	33,437	39,153	11%	(5%)	93,148	135,392	(31%)
Netbacks ($/boe)								
Sales	28.75	25.39	32.78	13%	(12%)	24.89	36.34	(32%)
Royalties	(2.15)	(1.55)	(2.81)	39%	(23%)	(1.92)	(3.09)	(38%)
Transportation	(1.77)	(1.55)	(1.75)	14%	1%	(1.62)	(1.85)	(12%)
Operating	(6.95)	(6.77)	(10.10)	3%	(31%)	(7.29)	(9.50)	(23%)
General and administration	(1.34)	(1.77)	(1.56)	(24%)	(14%)	(1.34)	(1.95)	(31%)
Fund flows from operations netback	16.54	13.75	16.56	20%	-	12.72	19.95	(36%)
Realized prices								
Crude oil and condensate ($/bbl)	53.96	56.67	56.95	(5%)	(5%)	49.75	58.99	(16%)
NGLs ($/bbl)	12.49	9.56	2.73	31%	358%	9.73	11.35	(14%)
Natural gas ($/mmbtu)	2.39	1.34	2.88	78%	(17%)	1.87	2.88	(35%)
Total ($/boe)	28.75	25.39	32.78	13%	(12%)	24.89	36.34	(32%)
Reference prices								
WTI (US $/bbl)	44.94	45.59	46.43	(1%)	(3%)	41.33	51.00	(19%)
Edmonton Sweet index (US $/bbl)	42.06	42.51	43.01	(1%)	(2%)	38.11	46.64	(18%)
Edmonton Sweet index ($/bbl)	54.89	54.78	56.32	-	(3%)	50.41	58.77	(14%)
AECO ($/mmbtu)	2.32	1.40	2.90	66%	(20%)	1.85	2.77	(33%)

Production

- Q3 2016 average production in Canada decreased by 9% quarter-over-quarter and 5% year-over-year due to production declines, the impact of a voluntary curtailment of natural gas-weighted production in response to low AECO prices and weather related power outages impacting Saskatchewan production. The year-over-year decrease was partially offset by organic production growth in our Mannville condensate-rich gas resource play.
- Cardium production averaged approximately 6,600 boe/d in Q3 2016, a 2% decrease quarter-over-quarter.
- Mannville production averaged approximately 10,200 boe/d in Q3 2016 representing an 11% decrease quarter-over-quarter and an increase of 48% from Q3 2015 production of approximately 6,900 boe/d.
- Production from our southeast Saskatchewan assets averaged approximately 2,400 boe/d in Q3 2016, a decrease of 15% quarter-over-quarter due to major power outages largely related to weather.

Activity review

- Vermilion participated in the drilling of four (1.2 net) non-operated wells during Q3 2016.

  Cardium

  - Prior to Q3 2016, one (0.1 net) non-operated well was drilled and three (0.5 net) non-operated wells were brought on production, completing our planned activity for the year.

  Mannville

  - During Q3 2016, we participated in the drilling of four (1.2 net) non-operated wells and two (0.7 net) non-operated wells were brought on production.
  - In 2016, we plan to drill or participate in 17 (10.6 net) wells; ten (5.0 net) wells have been drilled to date.

  Saskatchewan

  - Prior to Q3 2016, we drilled four (4.0 net) operated wells and participated in three (1.5 net) non-operated wells. We plan to complete and bring the four operated wells on production in Q1 2017. The non-op wells were brought on production during the first half of 2016.
  - 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.
- Q3 2016 sales per boe increased versus Q2 2016 due to stronger AECO pricing.
- Sales per boe for the three and nine months ended September 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 Q3 2016 increased to 7.5% as compared to 6.1% in Q2 2016 as a result of an annual favourable gas cost allowance adjustment in Alberta recorded in the second quarter of 2016.
- Royalties as a percentage of sales for the three and nine months ended September 30, 2016 decreased to 7.5% and 7.7% versus 8.6% 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 Q3 2016 was lower than Q3 2015 due to lower production.
- Transportation expense for the nine months ended September 30, 2016 was lower than the same period in the prior year despite an 8% increase in production due to an increased gas weighting and lower per unit rates.

Operating

- Operating expenses were lower on a dollar basis for Q3 2016 versus Q2 2016 and Q3 2015. On a per unit basis, costs were relatively consistent with Q2 2016 and down 31% from Q3 2015 due to our ability to execute on cost-cutting initiatives, including service cost negotiations impacting numerous cost drivers.
- Year-over-year operating expense decreased 17% while we achieved an 8% increase in production, resulting in a 23% reduction in per unit expenses as a result of initiatives to reduce our cost structure.

General and administration

- General and administration expense fluctuation in Q3 2016 as compared to Q2 2016 was the result of expenditure timing.
- Year-over-year, general and administration expense for the nine months ended September 30, 2016 was 26% 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.
- Low base decline producing assets comprised of large conventional oil fields with high working interests located in the Aquitaine and Paris Basins.
- Identified inventory of workover, infill drilling, and secondary recovery opportunities.

Operational and financial review

France business unit ($M except as indicated)	Three Months Ended Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	% change Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Nine Months Ended Sep 30, 2016	Sep 30, 2015	% change 2016 vs. 2015
Production								
Crude oil (bbls/d)	11,827	12,326	12,310	(4%)	(4%)	12,123	12,176	-
Natural gas (mmcf/d)	0.42	0.54	1.47	(22%)	(71%)	0.47	0.84	(44%)
Total (boe/d)	11,897	12,416	12,555	(4%)	(5%)	12,201	12,316	(1%)
Inventory (mbbls)								
Opening crude oil inventory	312	247	340			243	197	
Crude oil production	1,088	1,122	1,133			3,322	3,324	
Crude oil sales	(1,161)	(1,057)	(1,234)			(3,326)	(3,282)	
Closing crude oil inventory	239	312	239			239	239	
Activity								
Capital expenditures	11,110	12,772	17,369	(13%)	(36%)	37,345	68,180	(45%)
Acquisitions	-	-	142			-	238	
Gross wells drilled	-	-	-			-	4.00	
Net wells drilled	-	-	-			-	4.00	
Financial results								
Sales	65,221	61,591	76,552	6%	(15%)	174,937	218,011	(20%)
Royalties	(7,069)	(6,564)	(8,038)	8%	(12%)	(20,399)	(19,760)	3%
Transportation	(3,586)	(3,476)	(4,566)	3%	(21%)	(10,775)	(11,103)	(3%)
Operating	(12,933)	(11,265)	(11,998)	15%	8%	(38,518)	(34,926)	10%
General and administration	(4,590)	(4,734)	(5,338)	(3%)	(14%)	(14,000)	(15,323)	(9%)
Other income	-	-	-	-	-	-	31,775	(100%)
Current income taxes	955	(921)	(4,696)	(204%)	(120%)	-	(28,293)	(100%)
Fund flows from operations	37,998	34,631	41,916	10%	(9%)	91,245	140,381	(35%)
Netbacks ($/boe)								
Sales	55.88	57.82	60.96	(3%)	(8%)	52.26	65.66	(20%)
Royalties	(6.06)	(6.16)	(6.40)	(2%)	(5%)	(6.09)	(5.95)	2%
Transportation	(3.07)	(3.26)	(3.64)	(6%)	(16%)	(3.22)	(3.34)	(4%)
Operating	(11.08)	(10.57)	(9.55)	5%	16%	(11.51)	(10.52)	9%
General and administration	(3.93)	(4.44)	(4.25)	(11%)	(8%)	(4.18)	(4.61)	(9%)
Other income	-	-	-	-	-	-	9.57	(100%)
Current income taxes	0.82	(0.86)	(3.74)	(195%)	(122%)	-	(8.52)	(100%)
Fund flows from operations	32.56	32.53	33.38	-	(2%)	27.26	42.29	(36%)
Realized prices								
Crude oil ($/bbl)	56.14	58.19	61.75	(4%)	(9%)	52.53	66.26	(21%)
Natural gas ($/mmbtu)	1.58	1.58	2.93	-	(46%)	1.61	2.36	(32%)
Total ($/boe)	55.88	57.82	60.96	(3%)	(8%)	52.26	65.66	(20%)
Reference prices								
Dated Brent (US $/bbl)	45.85	45.57	50.26	1%	(9%)	41.77	55.39	(25%)
Dated Brent ($/bbl)	59.84	58.72	65.81	2%	(9%)	55.25	69.79	(21%)

Production

- Q3 2016 production decreased 4% versus the prior quarter and 5% versus Q3 2015 due to production declines, well downtime and third party restrictions impacting Vic Bilh gas production.

Activity review

- During the quarter we continued our 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.
- Q3 2016 sales per boe was relatively consistent with Q2 2016.
- Sales per boe for the three and nine months ended September 30, 2016, decreased versus the comparable periods in 2015 as a result of lower 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 10.8% and 11.7% for the three and nine months ended September 30, 2016, consistent with the 10.7% realized in Q2 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 per boe for the three months ended September 30, 2016 decreased 6% and 16% respectively from Q2 2016 and Q3 2015 as a result of successful vessel cost renegotiations and a lower level of project activity at the Ambès terminal.
- Transportation expense per boe for the nine months ended September 30, 2016 decreased by 4% versus the comparable period in 2015 as a result of initiatives to reduce our cost structure.

Operating

- Operating expense on a dollar and per boe basis increased for the three and nine months ended September 30, 2016 versus the same periods in 2015. These increases were primarily due to increased project costs and timing of credits received on electricity charges. On a year-over-year basis, operating expenses were further impacted by unfavourable foreign exchange rates as the Canadian dollar weakened versus the Euro. After normalizing for the unfavourable foreign exchange, per unit costs have increased 4% for the nine months ended September 30, 2016.

General and administration

- General and administration expense for the three and nine months ended September 30, 2016 decreased by 14% and 9% 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 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 Q3 2016 were lower compared to Q2 2016 due to decreased forecasted revenues for the full year 2016. Q3 2016 current income taxes were lower compared to Q3 2015 due to decreased sales.
- Current income taxes for the nine months ended September 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		Nine Months Ended		% change
Netherlands business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Condensate (bbls/d)	86	96	109	(10%)	(21%)	99	95	4%
Natural gas (mmcf/d)	47.62	49.18	53.56	(3%)	(11%)	50.06	40.86	23%
Total (boe/d)	8,023	8,293	9,035	(3%)	(11%)	8,442	6,905	22%
Activity								
Capital expenditures	6,441	8,566	5,297	(25%)	22%	18,003	28,515	(37%)
Gross wells drilled	2.00	-	-			2.00	2.00	
Net wells drilled	0.88	-	-			0.88	1.86	
Financial results								
Sales	23,470	23,973	41,083	(2%)	(43%)	74,729	91,814	(19%)
Royalties	(312)	(396)	(638)	(21%)	(51%)	(1,168)	(2,858)	(59%)
Operating	(4,854)	(4,306)	(5,243)	13%	(7%)	(15,136)	(16,483)	(8%)
General and administration	633	(1,223)	(2,154)	(152%)	(129%)	(1,363)	(3,345)	(59%)
Current income taxes	(1,264)	(3,260)	(4,487)	(61%)	(72%)	(6,724)	(9,222)	(27%)
Fund flows from operations	17,673	14,788	28,561	20%	(38%)	50,338	59,906	(16%)
Netbacks ($/boe)								
Sales	31.80	31.77	49.42	-	(36%)	32.31	48.70	(34%)
Royalties	(0.42)	(0.52)	(0.77)	(19%)	(45%)	(0.50)	(1.52)	(67%)
Operating	(6.58)	(5.71)	(6.31)	15%	4%	(6.54)	(8.74)	(25%)
General and administration	0.86	(1.62)	(2.59)	(153%)	(133%)	(0.59)	(1.77)	(67%)
Current income taxes	(1.71)	(4.32)	(5.40)	(60%)	(68%)	(2.91)	(4.89)	(40%)
Fund flows from operations netback	23.95	19.60	34.35	22%	(30%)	21.77	31.78	(31%)
Realized prices								
Condensate ($/bbl)	49.43	45.05	46.65	10%	6%	41.43	50.63	(18%)
Natural gas ($/mmbtu)	5.27	5.27	8.24	-	(36%)	5.37	8.11	(34%)
Total ($/boe)	31.80	31.77	49.42	-	(36%)	32.31	48.70	(34%)
Reference prices								
TTF ($/mmbtu)	5.43	5.61	8.48	(3%)	(36%)	5.58	8.52	(35%)
TTF (€/mmbtu)	3.73	3.86	5.82	(3%)	(36%)	3.78	6.07	(38%)

Production

- Q3 2016 production decreased 3% versus the prior quarter due to expected production curtailments pending approval to increase production rates at the conclusion of extended well testing being conducted at Slootdorp 06/07 and Diever-02. We expect the extended well tests to be completed, and the related approvals to be received, during the first half of 2017.
- Year-over-year production decreased 11%, as the Slootdorp-06/07 wells came on production in Q3 2015 at higher rates pursuant to the extended well test plan.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

Activity review

- We completed our two-well drilling campaign in the Netherlands during the quarter. Langezwaag-3 encountered 17 meters of net pay in the Zechstein-2 carbonate formation. This well is being completed and is expected to be placed on production in November, at which time an in-line production test will be conducted. Andel-6ST encountered a large gas column of inadequate reservoir quality to justify completion. Potential remains to sidetrack this well to an updip location where higher quality gas zones may be encountered. The well has been suspended to allow us to reprocess seismic data to determine the viability of the potential updip target.

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.
- Q3 2016 sales per boe was consistent with Q2 2016, despite a slight decline in the TTF reference price, due to the timing of sales.
- Sales per boe for the three and nine months ended September 30, 2016 decreased versus the comparable periods in the prior year, consistent with a decrease in the TTF reference price.

Royalties

- In the Netherlands, we pay overriding royalties on certain wells. As such, fluctuations in royalty expense in the periods presented 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

- For the three months ended September 30, 2016 operating expense was higher on a dollar basis versus Q2 2016 and lower than Q3 2015. The increase from Q2 2016 was due to timing of project work and the decrease from Q3 2015 was due to initiatives to reduce our cost structure and lower volumes.
- For the nine months ended September 30, 2016 operating costs have decreased 8% as compared to the same period in the prior year. This decrease is primarily due to our ongoing focus on cost control, while increasing produced volumes by 22%, resulting in a per unit cost decrease of 25%.

General and administration

- Variances in general and administration expense 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 10% and 12% 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 Q3 2016 were lower compared to Q2 2016 due to increased tax deductions for current year capital expenditures. Q3 2016 current income taxes were lower compared to Q3 2015 mainly due to decreased sales.
- Current income taxes for the nine months ended September 30, 2016 were lower versus the comparative period in 2015 as a result of decreased sales in 2016 which offset tax deductions for capital expenditures in 2015.

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 2015.
- 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.

Operational and financial review

	Three Months Ended			% change		Nine Months Ended		% change
Germany business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Natural gas (mmcf/d)	14.52	14.31	14.00	1%	4%	14.93	15.65	(5%)
Total (boe/d)	2,420	2,385	2,333	1%	4%	2,488	2,608	(5%)
Activity								
Capital expenditures	978	592	1,605	65%	(39%)	2,109	5,804	(64%)
Gross wells drilled	-	-	-			-	1.00	
Net wells drilled	-	-	-			-	0.25	
Financial results								
Sales	6,783	6,280	9,523	8%	(29%)	20,755	31,544	(34%)
Royalties	(246)	(964)	(1,477)	(74%)	(83%)	(2,077)	(5,313)	(61%)
Transportation	(556)	(1,051)	(627)	(47%)	(11%)	(2,494)	(2,761)	(10%)
Operating	(3,321)	(2,506)	(2,796)	33%	19%	(8,420)	(6,168)	37%
General and administration	(1,657)	(2,474)	(1,311)	(33%)	26%	(6,559)	(4,354)	51%
Fund flows from operations	1,003	(715)	3,312	(240%)	(70%)	1,205	12,948	(91%)
Netbacks ($/boe)								
Sales	30.47	28.94	44.36	5%	(31%)	30.45	44.30	(31%)
Royalties	(1.10)	(4.44)	(6.88)	(75%)	(84%)	(3.05)	(7.46)	(59%)
Transportation	(2.50)	(4.84)	(2.92)	(48%)	(14%)	(3.66)	(3.88)	(6%)
Operating	(14.92)	(11.55)	(13.03)	29%	15%	(12.35)	(8.66)	43%
General and administration	(7.44)	(11.40)	(6.11)	(35%)	22%	(9.62)	(6.12)	57%
Fund flows from operations netback	4.51	(3.29)	15.42	(237%)	(71%)	1.77	18.18	(90%)
Reference prices								
TTF ($/mmbtu)	5.43	5.61	8.48	(3%)	(36%)	5.58	8.52	(35%)
TTF (€/mmbtu)	3.73	3.86	5.82	(3%)	(36%)	3.78	6.07	(38%)

Production

- Q3 2016 production remained consistent with the prior quarter and Q3 2015.

Activity review

- In 2016, the majority of activity will be associated with permitting and pre-drill activities for the Burgmoor Z5 well. During Q3 2016, we continued our ongoing analysis of the proprietary geologic data associated with the farm-in assets and commenced integration activities associated with the Engie acquisition.

Sales

- The price of our natural gas in Germany is based on the TTF month-ahead index.
- Q3 2016 sales per boe increased versus Q2 2016, despite a slight decline in the TTF reference price, due to the timing of sales.
- Sales per boe for the three and nine months ended September 30, 2016 decreased versus the comparable periods in the prior year, 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 3.6% and 10.0% for the three and nine months ended September 30, 2016, a decrease from the 15.5% and 16.8% for the comparable periods in 2015. The decrease is due to favourable prior year adjustments impacting 2016.

Transportation

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer.
- Q3 2016 transportation expense decreased from Q2 2016 on a total dollar and per unit basis due to an unfavourable prior year adjustment recorded in the second quarter of 2016.
- Transportation expense decreased by 11% and 10% for the three and nine months ended September 30, 2016 compared to the same periods in 2015 due to lower unfavourable prior year adjustments in 2016.

Operating

- Operating expenses for Germany primarily relate to tariffs charged for facility operations and gas processing.
- Operating expense for Q3 2016 increased versus Q2 2016 and Q3 2015 due to a full year 2015 adjustment recorded in the current quarter.
- Year-to-date Q3 2016 operating expense increased versus 2015 on a total dollar and per unit basis due to higher levels of project activity and the aforementioned 2015 adjustment recorded in the current quarter.

General and administration

- Q3 2016 general and administration expenses were lower than Q2 2016 due to lower head office allocations.
- General and administration costs for the three and nine months ended September 30, 2016 were 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.
- Production volumes reached full plant capacity of approximately 65 mmcf/d (10,900 boe/d), net to Vermilion, at the end of Q2 2016.

Operational and financial review

	Three Months Ended			% change		Nine Months Ended		% change
Ireland business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Natural gas (mmcf/d)	59.28	47.26	-	25%	100%	46.86	-	100%
Total (boe/d)	9,879	7,877	-	25%	100%	7,810	-	100%
Activity								
Capital expenditures	2,416	2,172	20,694	11%	(88%)	7,664	53,916	(86%)
Financial results								
Sales	26,065	23,360	-	12%	100%	66,429	-	100%
Transportation	(1,576)	(1,574)	(1,766)	-	(11%)	(4,789)	(5,107)	(6%)
Operating	(4,695)	(5,177)	-	(9%)	100%	(13,498)	-	100%
General and administration	(955)	(1,106)	(663)	(14%)	44%	(3,249)	(1,803)	80%
Fund flows from operations	18,839	15,503	(2,429)	22%	(876%)	44,893	(6,910)	(750%)
Netbacks ($/boe)								
Sales	28.68	32.59	-	(12%)	100%	31.04	-	100%
Transportation	(1.73)	(2.20)	-	(21%)	100%	(2.24)	-	100%
Operating	(5.17)	(7.22)	-	(28%)	100%	(6.31)	-	100%
General and administration	(1.05)	(1.54)	-	(32%)	100%	(1.52)	-	100%
Fund flows from operations netback	20.73	21.63	-	(4%)	100%	20.97	-	
Reference prices								
NBP ($/mmbtu)	5.29	5.78	8.40	(8%)	(37%)	5.69	8.62	(34%)
NBP (€/mmbtu)	3.63	3.97	5.77	(9%)	(37%)	3.85	6.14	(37%)

Production

- Natural gas began to flow from our Corrib gas project on December 30, 2015 and production volumes reached full plant capacity of approximately 65 mmcf/d (10,900 boe/d), net to Vermilion at the end of Q2 2016
- Production averaged 59 mmcf/d (9,879 boe/d) net to Vermilion during Q3 2016, an increase of 25% versus the prior quarter.
- Production results continued to benefit from better than expected well deliverability and minimal downtime.

Activity review

- Following the conclusion of a successful offshore work campaign in Q3 2016 that included laying a flowline to the P2 well, all six wells are now available for production.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Q3 2016 sales per boe decreased relative to Q2 2016, consistent with a decrease in the NBP reference price.

Royalties

- Our production in Ireland is not subject to royalties.

Transportation

- Transportation expense in Ireland relates to payments under a ship or pay agreement related to the Corrib project.
- Transportation expense for the three and nine months ended September 30, 2016 is lower versus the comparable periods in 2015, due to a decrease in the ship or pay obligation.

Operating

- Q3 2016 operating expense decreased on a dollar basis from Q2 2016 by 9% due to less project activity. Production increased 25% over this period resulting in a 28% decrease in per unit costs.

General and administration

- General and administrative expense for the three and nine months ended September 30, 2016 is higher versus the comparable periods in 2015 due to increased corporate support provided for production operations now underway.

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		Nine Months Ended		% change
Australia business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Crude oil (bbls/d)	6,562	6,083	6,433	8%	2%	6,276	5,993	5%
Inventory (mbbls)								
Opening crude oil inventory	218	213	156			75	37	
Crude oil production	604	554	592			1,720	1,636	
Crude oil sales	(740)	(549)	(576)			(1,713)	(1,501)	
Closing crude oil inventory	82	218	172			82	172	
Activity								
Capital expenditures	6,908	39,939	7,966	(83%)	(13%)	54,674	20,889	162%
Gross wells drilled	-	2.00	-			2.00	-	
Net wells drilled	-	2.00	-			2.00	-	
Financial results								
Sales	44,835	33,713	39,325	33%	14%	98,483	114,813	(14%)
Operating	(13,011)	(12,100)	(13,766)	8%	(5%)	(32,602)	(37,735)	(14%)
General and administration	(1,289)	(1,788)	(1,391)	(28%)	(7%)	(4,402)	(3,986)	10%
PRRT	272	(144)	(99)	(289%)	(375%)	-	(5,824)	(100%)
Current income taxes	(2,916)	(1,126)	(2,720)	159%	7%	(4,819)	(8,431)	(43%)
Fund flows from operations	27,891	18,555	21,349	50%	31%	56,660	58,837	(4%)
Netbacks ($/boe)								
Sales	60.61	61.53	68.20	(1%)	(11%)	57.51	76.46	(25%)
Operating	(17.59)	(22.08)	(23.87)	(20%)	(26%)	(19.04)	(25.13)	(24%)
General and administration	(1.74)	(3.26)	(2.41)	(47%)	(28%)	(2.57)	(2.65)	(3%)
PRRT	0.37	(0.26)	(0.17)	(242%)	(318%)	-	(3.88)	(100%)
Current income taxes	(3.94)	(2.05)	(4.72)	92%	(17%)	(2.81)	(5.61)	(50%)
Fund flows from operations netback	37.71	33.88	37.03	11%	2%	33.09	39.19	(16%)
Reference prices								
Dated Brent (US $/bbl)	45.85	45.57	50.26	1%	(9%)	41.77	55.39	(25%)
Dated Brent ($/bbl)	59.84	58.72	65.81	2%	(9%)	55.25	69.79	(21%)

Production

- Q3 2016 production increased 8% quarter-over-quarter and 2% 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

- The two sidetrack wells we drilled during the prior quarter continued to demonstrate strong productive capability during Q3 with combined production rates exceeding 4,500 bbls/d when utilized. Vermilion intends to produce these wells intermittently to meet corporate production targets while seeking to optimize ultimate recoveries and oil pricing. Following our successful 2015 and 2016 drilling campaigns, we do not expect to drill any additional wells in Australia until 2019.
- Late in the third quarter, we commenced a planned 10-day maintenance shutdown. The scope of activities was completed as scheduled and production resumed on October 3, 2016.
- We continued to advance our Wandoo Platforms Life Extension project during the quarter.

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Q3 2016 sales per boe were relatively consistent with Q2 2016.
- Sales per boe for the three and nine months ended September 30, 2016, decreased versus the comparable periods in 2015 due to weaker crude oil pricing. In both periods, this decline in price was partially offset by higher sales volumes, minimizing the impact on 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 Q2 2016 primarily due to a 35% increase in volumes sold. On a per unit basis costs decreased by 20% primarily due to lower diesel costs.
- Year-over-year operating expense is down 5% and 14% for the three and nine months ended September 30, 2016 versus the comparable periods in 2015. These decreases have been achieved while growing production and sales through a continued focus on cost reduction initiatives, including reduced helicopter and vessel costs. As a result, per unit costs have decreased by 26% and 24% respectively for the three and nine months ended September 30, 2016 versus 2015.

General and administration

- Fluctuation in general and administration expense for the three and nine months ended September 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 8% to 10% 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 Q3 2016 were higher compared to Q2 2016 due to an increase in sales. Q3 2016 current income taxes were higher compared to Q3 2015 due to increased sales partially offset with higher tax deductions for capital expenditures.
- PRRT in Q3 2016 was relatively flat compared to Q2 2016 and Q3 2015 as sales were offset with capital expenditures.
- Current income taxes and PRRT for the nine months ended September 30, 2016 were lower versus the comparable period in 2015 as a result of decreased sales and higher tax deductions for capital expenditures.

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		Nine Months Ended		% change
United States business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Crude oil (bbls/d)	383	458	226	(16%)	69%	403	168	140%
NGLs (bbls/d)	30	26	-	15%	100%	32	-	100%
Natural gas (mmcf/d)	0.20	0.20	-	-	100%	0.21	-	100%
Total (boe/d)	447	518	226	(14%)	98%	472	168	181%
Activity								
Capital expenditures	2,765	1,636	3,226	69%	(14%)	9,502	6,607	44%
Acquisitions	11	5,432	12,785			5,558	12,785	
Gross wells drilled	-	-	-			-	1.00	
Net wells drilled	-	-	-			-	1.00	
Financial results								
Sales	1,833	2,207	1,075	(17%)	71%	5,273	2,424	118%
Royalties	(525)	(661)	(309)	(21%)	70%	(1,556)	(706)	120%
Operating	(432)	(302)	(146)	43%	196%	(1,013)	(471)	115%
General and administration	(918)	(697)	(896)	32%	2%	(2,747)	(2,939)	(7%)
Fund flows from operations	(42)	547	(276)	(108%)	(85%)	(43)	(1,692)	(97%)
Netbacks ($/boe)								
Sales	44.53	46.80	51.60	(5%)	(14%)	40.78	52.95	(23%)
Royalties	(12.74)	(14.02)	(14.83)	(9%)	(14%)	(12.03)	(15.42)	(22%)
Operating	(10.50)	(6.39)	(6.98)	64%	50%	(7.84)	(10.28)	(24%)
General and administration	(22.30)	(14.77)	(43.03)	51%	(48%)	(21.25)	(64.20)	(67%)
Fund flows from operations netback	(1.01)	11.62	(13.24)	(109%)	(92%)	(0.34)	(36.95)	(99%)
Realized prices								
Crude oil ($/bbl)	51.29	52.56	51.60	(2%)	(1%)	47.07	52.95	(11%)
NGLs ($/bbl)	5.14	3.25	-	58%	100%	4.49	-	100%
Natural gas ($/mmbtu)	0.64	0.37	-	73%	100%	0.57	-	100%
Total ($/boe)	44.53	46.80	51.60	(5%)	(14%)	40.78	52.95	(23%)
Reference prices								
WTI (US $/bbl)	44.94	45.59	46.43	(1%)	(3%)	41.33	51.00	(19%)
WTI ($/bbl)	58.65	58.75	60.80	-	(4%)	54.67	64.26	(15%)
Henry Hub (US $/mmbtu)	2.81	1.95	2.77	44%	1%	2.29	2.80	(18%)
Henry Hub ($/mmbtu)	3.67	2.52	3.62	46%	1%	3.03	3.52	(14%)

Production

- Q3 2016 production decreased 14% versus the prior quarter due to natural declines and downtime associated with the attempted repair of the Reed 17-1H well following a mechanical failure during the well's completion. The repair was unsuccessful in establishing communication with the remainder of the hydraulically-fractured horizontal lateral, and the well was returned to production during the quarter.

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 are approximately 30% and has remained consistent across all periods.

Operating

- The increase in operating expense for Q3 2016 compared to Q2 2016 and Q3 2015 was primarily due to increased project activity and well repairs in the current quarter.
- On a year-over-year basis, per unit costs have decreased 24% due to production growth and initiatives to reduce our cost structure.

General and administration

- On a year-over-year basis cost-cutting initiatives have resulted in a 7% 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. Expenditures relating to our activities in Central and Eastern Europe are also included in the Corporate segment.

Financial review

CORPORATE ($M)	Three Months Ended Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Nine Months Ended Sep 30, 2016	Sep 30, 2015
General and administration (expense) recovery	(509)	834	2,359	746	3,816
Current income taxes	(321)	(257)	(480)	(727)	(1,404)
Interest expense	(14,150)	(13,647)	(15,420)	(42,547)	(43,268)
Realized gain on derivatives	13,532	21,501	10,854	63,456	20,192
Realized foreign exchange gain	2,073	1,329	309	2,750	875
Realized other (expense) income	(82)	62	227	85	653
Fund flows from operations	543	9,822	(2,151)	23,763	(19,136)

General and administration

- The fluctuations in general and administration costs for Q3 2016 versus all comparable periods is due to the timing of expenditures and allocations to the various business unit segments.

Current income taxes

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

Interest expense

- Interest expense in Q3 2016 was relatively consistent with Q2 2016.
- The decrease in interest expense for the three and nine months ended September 30, 2016, was 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%. This was partially 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 for 2018 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 on derivatives in Q3 2016 related primarily to amounts received on our European natural gas hedges.
- A listing of derivative positions as at September 30, 2016 is included in “Supplemental Table 2” of this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Three Months Ended							
($M except per share)	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016	Dec 31, 2015	Sep 30, 2015	Jun 30, 2015	Mar 31, 2015	Dec 31, 2014
Petroleum and natural gas sales	232,660	212,855	177,385	234,319	245,051	264,331	195,885	306,073
Net (loss) earnings	(14,475)	(55,696)	(85,848)	(142,080)	(83,310)	6,813	1,275	58,642
Net (loss) earnings per share								
Basic	(0.12)	(0.48)	(0.76)	(1.28)	(0.76)	0.06	0.01	0.55
Diluted	(0.12)	(0.48)	(0.76)	(1.28)	(0.76)	0.06	0.01	0.54

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

	Three Months Ended			Nine Months Ended	
	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Sep 30, 2016	Sep 30, 2015
Fund flows from operations	140,974	126,568	129,435	361,209	379,726
Equity based compensation	(15,642)	(13,267)	(16,773)	(49,746)	(53,699)
Unrealized gain (loss) on derivative instruments	332	(72,436)	32,020	(63,050)	16,155
Unrealized foreign exchange gain (loss)	2,899	(2,804)	14,958	1,665	15,144
Unrealized other expense	(24)	(20)	(309)	(131)	(774)
Accretion	(6,341)	(6,025)	(6,199)	(18,475)	(17,587)
Depletion and depreciation	(143,556)	(131,793)	(148,843)	(401,147)	(350,946)
Deferred tax	6,883	44,081	55,401	28,418	79,759
Impairment	-	-	(143,000)	(14,762)	(143,000)
Net loss	(14,475)	(55,696)	(83,310)	(156,019)	(75,222)

The fluctuations in net income from period-to-period are caused by changes in both cash and non-cash based income and charges. Cash based items are reflected in fund flows from operations 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 in Q3 2016 increased as compared to Q2 2016 due to a revision of performance estimates. For the three and nine months ended September 30, 2016, the decrease in equity based compensation is primarily due to the lower average grant value of outstanding awards.

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 well as the impact of contracts settled during the period. 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 nine months ended September 30, 2016, we recognized an unrealized loss on derivative instruments of $63.1 million. This unrealized loss resulted from realizing gains on derivatives for contracts settled during the period, coupled with higher forward prices for European natural gas as at September 30, 2016. As at September 30, 2016, we have a net derivative asset position of $5.3 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 September 30, 2016, the Canadian dollar weakened more significantly against the Euro than the US dollar, resulting in an unrealized foreign exchange gain of $2.9 million. For the nine months ended September 30, 2016, the Canadian dollar strengthened more significantly against the US dollar than the Euro, resulting in an unrealized foreign exchange gain of $1.7 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.

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 Q3 2016 of $23.69 was relatively consistent as compared to $22.80 in Q2 2016.

For the three and nine months ended September 30, 2016, depletion and depreciation on a per boe basis of $23.69 and $22.73 was lower than $28.28 and $24.62 in the same periods of 2015 due to increased production from our Mannville condensate-rich gas properties, which have lower per boe depletion.

Deferred tax

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

Impairment

In Q1 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 shortfall with debt (including borrowing using the unutilized capacity of our existing revolving credit facility), issue equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

To ensure that we maintain a conservative balance sheet, we monitor the ratio of net debt to fund flows from operations and typically strive to maintain an internally targeted ratio of approximately 1.0 to 1.5 in a normalized commodity price environment. Where prices trend higher, we may target a lower ratio and conversely, in a lower commodity price environment, 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 September 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)	Sep 30, 2016	Dec 31, 2015
Revolving credit facility	1,312,652	1,162,998
Senior unsecured notes	-	224,901
Long-term debt	1,312,652	1,387,899

Revolving Credit Facility

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

	As at	
	Sep 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	$21.0 million	$25.2 million
Facility maturity date	31-May-19	31-May-19

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

		As at	
Financial covenant	Limit	Sep 30, 2016	Dec 31, 2015
Consolidated total debt to consolidated EBITDA	4.0	2.36	2.23
Consolidated total senior debt to total capitalization	55%	44%	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:

($M)	As at Sep 30, 2016	As at Dec 31, 2015
Long-term debt	1,312,652	1,162,998
Current liabilities [1]	246,498	503,731
Current assets	(215,227)	(284,778)
Net debt	1,343,923	1,381,951
Ratio of net debt to annualized fund flows from operations	2.8	2.7

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

As at September 30, 2016, long term debt decreased to $1.31 billion (December 31, 2015 - $1.39 billion, including the current portion of long-term debt) as fund flows from operations generated in excess of capital expenditures, abandonment expenditures, acquisitions, and cash dividends was used to reduce debt. The decrease in long-term debt was coupled with working capital changes, such that net debt decreased from $1.38 billion at December 31, 2015 to $1.34 billion at September 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 slightly from 2.7 to 2.8.

Shareholders’ capital

During the nine months ended September 30, 2016, we maintained monthly dividends at $0.215 per share and declared dividends which totalled $223.0 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.

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. Both components of our program can be reduced or eliminated at the company’s discretion, offering considerable flexibility.

As previously announced, we commenced proration of the Premium Dividend™ of our Dividend Reinvestment Plan by 25% beginning with our October dividend payment. Eligible shareholders who have elected to participate in the Premium Dividend™ component are now receiving the 1.5% premium on 75% of their participating shares and the regular cash dividend on the remaining 25% of their shares. We expect to increase the proration factor by a further 25% beginning with the January 2017 dividend payment. Subject to unexpected changes in the commodity price outlook, we will continue to increase the proration during 2017, at the end of which there would be no further equity issuance under the Premium Dividend™ component of our Dividend Reinvestment Plan. We also intend to reduce the discount associated with our traditional Dividend Reinvestment Plan from 3% to 2%, beginning with the January 2017 dividend payment (subject to TSX approval).

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 shortfall with debt, issuances of equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount ($M)
Balance as at December 31, 2015	111,991	2,181,089
Shares issued for the DRIP(1)	3,823	149,418
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	165	6,700
Balance as at September 30, 2016	117,386	2,407,595

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

As at September 30, 2016, there were approximately 1.7 million VIP awards outstanding. As at October 28, 2016, there were approximately 117.7 million common shares issued and outstanding.

ASSET RETIREMENT OBLIGATIONS

As at September 30, 2016, asset retirement obligations were $344.0 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 obligation and accretion expense.

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 September 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 nine months ended September 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 September 30, 2016			Nine Months Ended September 30, 2016			Three Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2015
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	45.08	2.39	28.75	41.23	1.87	24.89	32.78	36.34
Royalties	(3.64)	(0.14)	(2.15)	(3.85)	(0.05)	(1.92)	(2.81)	(3.09)
Transportation	(2.56)	(0.18)	(1.77)	(2.36)	(0.17)	(1.62)	(1.75)	(1.85)
Operating	(8.36)	(0.95)	(6.95)	(7.64)	(1.17)	(7.29)	(10.10)	(9.50)
Operating netback	30.52	1.12	17.88	27.38	0.48	14.06	18.12	21.90
General and administration			(1.34)			(1.34)	(1.56)	(1.95)
Fund flows from operations netback			16.54			12.72	16.56	19.95
France								
Sales	56.14	1.58	55.88	52.53	1.61	52.26	60.96	65.66
Royalties	(6.08)	(0.32)	(6.06)	(6.12)	(0.34)	(6.09)	(6.40)	(5.95)
Transportation	(3.09)	-	(3.07)	(3.24)	-	(3.22)	(3.64)	(3.34)
Operating	(11.06)	(2.55)	(11.08)	(11.49)	(2.35)	(11.51)	(9.55)	(10.52)
Operating netback	35.91	(1.29)	35.67	31.68	(1.08)	31.44	41.37	45.85
General and administration			(3.93)			(4.18)	(4.25)	(4.61)
Other income			-			-	-	9.57
Current income taxes			0.82			-	(3.74)	(8.52)
Fund flows from operations netback			32.56			27.26	33.38	42.29
Netherlands								
Sales	49.43	5.27	31.80	41.43	5.37	32.31	49.42	48.70
Royalties	-	(0.07)	(0.42)	-	(0.09)	(0.50)	(0.77)	(1.52)
Operating	-	(1.11)	(6.58)	-	(1.10)	(6.54)	(6.31)	(8.74)
Operating netback	49.43	4.09	24.80	41.43	4.18	25.27	42.34	38.44
General and administration			0.86			(0.59)	(2.59)	(1.77)
Current income taxes			(1.71)			(2.91)	(5.40)	(4.89)
Fund flows from operations netback			23.95			21.77	34.35	31.78
Germany								
Sales	-	5.08	30.47	-	5.07	30.45	44.36	44.30
Royalties	-	(0.18)	(1.10)	-	(0.51)	(3.05)	(6.88)	(7.46)
Transportation	-	(0.42)	(2.50)	-	(0.61)	(3.66)	(2.92)	(3.88)
Operating	-	(2.49)	(14.92)	-	(2.06)	(12.35)	(13.03)	(8.66)
Operating netback	-	1.99	11.95	-	1.89	11.39	21.53	24.30
General and administration			(7.44)			(9.62)	(6.11)	(6.12)
Fund flows from operations netback			4.51			1.77	15.42	18.18
Ireland								
Sales	-	4.78	28.68	-	5.17	31.04	-	-
Transportation	-	(0.29)	(1.73)	-	(0.37)	(2.24)	-	-
Operating	-	(0.86)	(5.17)	-	(1.05)	(6.31)	-	-
Operating netback	-	3.63	21.78	-	3.75	22.49	-	-
General and administration			(1.05)			(1.52)	-	-
Fund flows from operations netback			20.73			20.97	-	-
Australia								
Sales	60.61	-	60.61	57.51	-	57.51	68.20	76.46
Operating	(17.59)	-	(17.59)	(19.04)	-	(19.04)	(23.87)	(25.13)
PRRT (1)	0.37	-	0.37	-	-	-	(0.17)	(3.88)
Operating netback	43.39	-	43.39	38.47	-	38.47	44.16	47.45
General and administration			(1.74)			(2.57)	(2.41)	(2.65)
Corporate income taxes			(3.94)			(2.81)	(4.72)	(5.61)
Fund flows from operations netback			37.71			33.09	37.03	39.19

	Three Months Ended September 30, 2016			Nine Months Ended September 30, 2016			Three Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2015
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/bbl	Total $/boe
United States								
Sales	47.91	0.64	44.53	43.96	0.57	40.78	51.60	52.95
Royalties	(13.61)	(0.39)	(12.74)	(12.89)	(0.33)	(12.03)	(14.83)	(15.42)
Operating	(11.38)	-	(10.50)	(8.50)	-	(7.84)	(6.98)	(10.28)
Operating netback	22.92	0.25	21.29	22.57	0.24	20.91	29.79	27.25
General and administration			(22.30)			(21.25)	(43.03)	(64.20)
Fund flows from operations netback			(1.01)			(0.34)	(13.24)	(36.95)
Total Company								
Sales	53.24	3.98	38.40	48.95	3.76	35.29	46.56	49.48
Realized hedging gain	0.40	0.67	2.23	1.77	0.88	3.60	2.06	1.42
Royalties	(3.80)	(0.09)	(2.14)	(4.08)	(0.08)	(2.23)	(3.25)	(3.48)
Transportation	(2.09)	(0.19)	(1.60)	(2.19)	(0.21)	(1.70)	(2.11)	(2.21)
Operating	(11.70)	(1.08)	(9.05)	(11.42)	(1.19)	(9.21)	(10.99)	(11.25)
PRRT [(1)]	0.09	-	0.04	-	-	-	(0.02)	(0.41)
Operating netback	36.14	3.29	27.88	33.03	3.16	25.75	32.25	33.55
General and administration			(2.03)			(2.34)	(2.49)	(2.89)
Interest expense			(2.34)			(2.41)	(2.93)	(3.04)
Realized foreign exchange gain			0.34			0.16	0.06	0.06
Other (expense) income			(0.01)			-	0.04	2.28
Corporate income taxes [(1)]			(0.59)			(0.70)	(2.35)	(3.32)
Fund flows from operations netback			23.25			20.46	24.58	26.64

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

Supplemental Table 2: Hedges

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

The following tables outline Vermilion's outstanding risk management positions as at September 30, 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	Jul 2016 - Dec 2016	USD	3,000	48.68	3,000	60.00	3,000	39.33
3-Way Collar [1]	Jan 2017 - Dec 2017	USD	2,000	50.00	2,000	60.00	2,000	40.00

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) [2]
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	Aug 2016 - Oct 2016	CAD	-	-	-	-	2,370	2.56	-
Swap	Nov 2016 - Dec 2017	CAD	-	-	-	-	2,370	2.99	-
Swap	Jan 2017 - Dec 2017	CAD	-	-	-	-	7,109	2.94	-
AECO Basis									
Swap	Jan 2017 - Dec 2017	USD	-	-	-	-	5,000	(0.75)	-
Swap	Jan 2018 - Dec 2018	USD	-	-	-	-	7,500	(0.83)	-
NYMEX									
Swap	Jan 2017 - Dec 2017	USD	-	-	-	-	5,000	3.00	-

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) [2]
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 - Sep 2017	GBP	5,000	3.25	10,000	4.03	-	-	-
Collar	Oct 2016 - Dec 2017	GBP	5,000	3.25	10,000	4.07	-	-	-
Collar	Jan 2017 - Dec 2017	GBP	5,000	3.30	7,500	3.77	-	-	-
Collar	Jan 2018 - Dec 2018	GBP	2,500	3.15	2,500	3.82	-	-	-
Put [3]	Dec 2016 - Feb 2017	GBP	20,000	4.00	-	-	-	-	-
Call	Oct 2016 - Mar 2017	GBP	-	-	2,500	4.90	-	-	-
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	-

(1) To fund the execution of the 3-way collar, Vermilion sold a swaption instrument. This instrument allows the counterparty, on December 30, 2016, to enter into a Dated Brent swap price of US$55.00 for 1,000 bbls/d for 2017.

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

(3) To fund the execution of the put, Vermilion sold a swaption instrument. This instrument allows the counterparty, on December 29, 2016, to enter into a NBP swap with Vermilion at a swap price of £4.20 per mmbtu for 5,300 mmbtu/d for the period of April 2017 to March 2018.

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	Sold Put / Swap Volume (mmbtu/d)	Weighted Average Sold Put / Swap Price / mmbtu	Additional Swap Volume (mmbtu/d) [1]
TTF									
3-Way Collar [2]	Apr 2017 - Sep 2017	EUR	9,827	4.18	9,827	5.06	9,827	3.08	-
3-Way Collar [2]	Jan 2018 - Dec 2018	EUR	4,913	4.40	4,913	5.28	4,913	3.22	-
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 - Sep 2017	EUR	2,457	3.81	4,913	4.47	-	-	-
Collar	Jan 2018 - Dec 2018	EUR	4,913	4.40	4,913	5.31	-	-	-
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
Swap	Oct 2017 - Dec 2018	EUR	-	-	-	-	2,457	4.69	-

Fuel and Electricity	Period	Currency	Swap Volume (unit/d)	Weighted 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			Notional amount	Rate (%)
CDOR Swap	Sep 2015 - Sep 2019	CAD	100,000,000	1.00
CDOR Swap	Oct 2015 - Oct 2019	CAD	100,000,000	1.10

Cross Currency		Receive Notional amount (USD)	Rate (US%)	Pay Notional amount (CAD)	Rate (CAD%)
Swap [3]	Oct 2016	872,238,352	3.27	1,145,799,999	3.15

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

(2) To fund the execution of the 3-way collar, Vermilion sold a swaption instrument. This instrument allows the counterparty, on March 31, 2017, to enter into a TTF swap price of €4.55 per mmbtu for 4,913 mmbtu/d for the period of April 2017 to June 2018.

(3) Subsequent to September 30, 2016, Vermilion repaid $1.1 billion of borrowings on the revolving credit facility bearing interest at CDOR plus applicable margins and simultaneously borrowed US $0.9 billion on the revolving credit facility bearing interest at LIBOR plus applicable margins.

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Three Months Ended Sep 30, 2016	Three Months Ended Jun 30, 2016	Three Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2016	Nine Months Ended Sep 30, 2015
Drilling and development	41,039	71,296	93,381	175,108	357,865
Exploration and evaluation	-	418	-	418	-
Capital expenditures	41,039	71,714	93,381	175,526	357,865
Property acquisition	10,391	8,550	22,155	19,811	22,670
Acquisitions	10,391	8,550	22,155	19,811	22,670

By category ($M)	Three Months Ended Sep 30, 2016	Three Months Ended Jun 30, 2016	Three Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2016	Nine Months Ended Sep 30, 2015
Land	(36)	493	763	1,496	2,974
Seismic	1,110	1,323	810	8,701	4,026
Drilling and completion	18,694	36,542	39,712	83,089	154,031
Production equipment and facilities	18,046	35,612	44,589	59,896	163,301
Recompletions	603	768	3,948	4,969	20,351
Other	2,622	(3,024)	3,559	17,375	13,182
Capital expenditures	41,039	71,714	93,381	175,526	357,865
Acquisitions	10,391	8,550	22,155	19,811	22,670
Total capital expenditures and acquisitions	51,430	80,264	115,536	195,337	380,535

By country ($M)	Three Months Ended Sep 30, 2016	Three Months Ended Jun 30, 2016	Three Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2016	Nine Months Ended Sep 30, 2015
Canada	20,801	6,415	45,286	57,742	182,435
France	11,110	12,772	17,511	37,345	68,418
Netherlands	6,441	8,566	5,297	18,003	28,515
Germany	978	592	1,605	2,109	5,804
Ireland	2,416	2,172	20,694	7,664	53,916
Australia	6,908	39,939	7,966	54,674	20,889
United States	2,776	7,068	16,011	15,060	19,392
Corporate	-	2,740	1,166	2,740	1,166
Total capital expenditures and acquisitions	51,430	80,264	115,536	195,337	380,535

Supplemental Table 4: Production

	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13
Canada												
Crude oil & condensate (bbls/d)	8,984	9,453	10,317	10,413	11,030	11,843	12,163	12,681	12,755	14,108	10,390	8,719
NGLs (bbls/d)	2,448	2,687	2,633	2,710	2,678	2,094	1,706	1,444	1,005	1,364	1,118	1,699
Natural gas (mmcf/d)	77.62	87.44	97.16	87.90	71.94	64.66	61.78	58.36	57.07	57.59	49.53	41.43
Total (boe/d)	24,368	26,713	29,141	27,773	25,698	24,713	24,165	23,851	23,272	25,070	19,763	17,322
% of consolidated	37%	42%	44%	45%	47%	48%	48%	49%	47%	49%	42%	43%
France												
Crude oil (bbls/d)	11,827	12,326	12,220	12,537	12,310	12,746	11,463	11,133	11,111	11,025	10,771	11,131
Natural gas (mmcf/d)	0.42	0.54	0.44	1.36	1.47	1.03	-	-	-	-	-	-
Total (boe/d)	11,897	12,416	12,293	12,763	12,555	12,917	11,463	11,133	11,111	11,025	10,771	11,131
% of consolidated	19%	19%	19%	21%	22%	25%	23%	22%	22%	21%	23%	27%
Netherlands												
Condensate (bbls/d)	86	96	114	110	109	112	63	81	63	96	69	62
Natural gas (mmcf/d)	47.62	49.18	53.40	56.34	53.56	32.43	36.41	31.35	38.07	40.35	43.15	37.53
Total (boe/d)	8,023	8,293	9,015	9,500	9,035	5,517	6,132	5,306	6,407	6,822	7,260	6,318
% of consolidated	13%	13%	14%	16%	16%	11%	12%	11%	13%	13%	16%	15%
Germany												
Natural gas (mmcf/d)	14.52	14.31	15.96	16.17	14.00	16.18	16.80	17.71	15.38	16.13	10.64	-
Total (boe/d)	2,420	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%	4%	5%	6%	6%	5%	5%	4%	-
Ireland												
Natural gas (mmcf/d)	59.28	47.26	33.90	0.12	-	-	-	-	-	-	-	-
Total (boe/d)	9,879	7,877	5,650	20	-	-	-	-	-	-	-	-
% of consolidated	16%	12%	9%	-	-	-	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	6,562	6,083	6,180	7,824	6,433	5,865	5,672	6,134	6,567	6,483	7,110	6,189
% of consolidated	10%	9%	9%	13%	11%	11%	11%	12%	13%	12%	15%	15%
United States												
Crude oil (bbls/d)	383	458	368	420	226	123	153	195	-	-	-	-
NGLs (bbls/d)	30	26	39	29	-	-	-	-	-	-	-	-
Natural gas (mmcf/d)	0.20	0.20	0.26	0.20	-	-	-	-	-	-	-	-
Total (boe/d)	447	518	450	483	226	123	153	195	-	-	-	-
% of consolidated	1%	1%	1%	1%	-	-	-	-	-	-	-	-
Consolidated												
Crude oil, condensate & NGLs (bbls/d)	30,320	31,129	31,871	34,043	32,786	32,783	31,220	31,668	31,501	33,076	29,458	27,800
% of consolidated	48%	48%	49%	56%	58%	63%	62%	64%	63%	63%	63%	68%
Natural gas (mmcf/d)	199.65	198.93	201.11	162.09	140.97	114.29	115.00	107.42	110.52	114.08	103.32	78.96
% of consolidated	52%	52%	51%	44%	42%	37%	38%	36%	37%	37%	37%	32%
Total (boe/d)	63,596	64,285	65,389	61,058	56,280	51,831	50,386	49,571	49,920	52,089	46,677	40,960

	YTD 2016	2015	2014	2013	2012	2011
Canada						
Crude oil & condensate (bbls/d)	9,582	11,357	12,491	8,387	7,659	4,701
NGLs (bbls/d)	2,589	2,301	1,233	1,666	1,232	1,297
Natural gas (mmcf/d)	87.37	71.65	55.67	42.39	37.50	43.38
Total (boe/d)	26,732	25,598	23,001	17,117	15,142	13,227
% of consolidated	41%	46%	47%	41%	40%	38%
France						
Crude oil (bbls/d)	12,123	12,267	11,011	10,873	9,952	8,110
Natural gas (mmcf/d)	0.47	0.97	-	3.40	3.59	0.95
Total (boe/d)	12,201	12,429	11,011	11,440	10,550	8,269
% of consolidated	19%	23%	22%	28%	28%	23%
Netherlands						
Condensate (bbls/d)	99	99	77	64	67	58
Natural gas (mmcf/d)	50.06	44.76	38.20	35.42	34.11	32.88
Total (boe/d)	8,442	7,559	6,443	5,967	5,751	5,538
% of consolidated	13%	14%	13%	15%	15%	16%
Germany						
Natural gas (mmcf/d)	14.93	15.78	14.99	-	-	-
Total (boe/d)	2,488	2,630	2,498	-	-	-
% of consolidated	4%	5%	5%	-	-	-
Ireland						
Natural gas (mmcf/d)	46.86	0.03	-	-	-	-
Total (boe/d)	7,810	5	-	-	-	-
% of consolidated	12%	-	-	-	-	-
Australia						
Crude oil (bbls/d)	6,276	6,454	6,571	6,481	6,360	8,168
% of consolidated	10%	12%	13%	16%	17%	23%
United States						
Crude oil (bbls/d)	403	231	49	-	-	-
NGLs (bbls/d)	32	7	-	-	-	-
Natural gas (mmcf/d)	0.21	0.05	-	-	-	-
Total (boe/d)	472	247	49	-	-	-
% of consolidated	1%	-	-	-	-	-
Consolidated						
Crude oil, condensate & NGLs (bbls/d)	31,104	32,716	31,432	27,471	25,270	22,334
% of consolidated	48%	60%	63%	67%	67%	63%
Natural gas (mmcf/d)	199.89	133.24	108.85	81.21	75.20	77.21
% of consolidated	52%	40%	37%	33%	33%	37%
Total (boe/d)	64,421	54,922	49,573	41,005	37,803	35,202

Supplemental Table 5: Segmented Financial Results

	Three Months Ended September 30, 2016								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Drilling and development	10,421	11,110	6,441	978	2,416	6,908	2,765	-	41,039
Oil and gas sales to external customers	64,453	65,221	23,470	6,783	26,065	44,835	1,833	-	232,660
Royalties	(4,817)	(7,069)	(312)	(246)	-	-	(525)	-	(12,969)
Revenue from external customers	59,636	58,152	23,158	6,537	26,065	44,835	1,308	-	219,691
Transportation	(3,978)	(3,586)	-	(556)	(1,576)	-	-	-	(9,696)
Operating	(15,579)	(12,933)	(4,854)	(3,321)	(4,695)	(13,011)	(432)	-	(54,825)
General and administration	(3,010)	(4,590)	633	(1,657)	(955)	(1,289)	(918)	(509)	(12,295)
PRRT	-	-	-	-	-	272	-	-	272
Corporate income taxes	-	955	(1,264)	-	-	(2,916)	-	(321)	(3,546)
Interest expense	-	-	-	-	-	-	-	(14,150)	(14,150)
Realized gain on derivative instruments	-	-	-	-	-	-	-	13,532	13,532
Realized foreign exchange gain	-	-	-	-	-	-	-	2,073	2,073
Realized other expense	-	-	-	-	-	-	-	(82)	(82)
Fund flows from operations	37,069	37,998	17,673	1,003	18,839	27,891	(42)	543	140,974

	Nine Months Ended September 30, 2016								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Total assets	1,507,693	816,731	186,524	154,699	807,534	258,257	54,953	129,026	3,915,417
Drilling and development	45,811	37,345	18,003	2,109	7,664	54,674	9,502	-	175,108
Exploration and evaluation	-	-	-	-	-	-	-	418	418
Oil and gas sales to external customers	182,294	174,937	74,729	20,755	66,429	98,483	5,273	-	622,900
Royalties	(14,085)	(20,399)	(1,168)	(2,077)	-	-	(1,556)	-	(39,285)
Revenue from external customers	168,209	154,538	73,561	18,678	66,429	98,483	3,717	-	583,615
Transportation	(11,888)	(10,775)	-	(2,494)	(4,789)	-	-	-	(29,946)
Operating	(53,382)	(38,518)	(15,136)	(8,420)	(13,498)	(32,602)	(1,013)	-	(162,569)
General and administration	(9,791)	(14,000)	(1,363)	(6,559)	(3,249)	(4,402)	(2,747)	746	(41,365)
PRRT	-	-	-	-	-	-	-	-	-
Corporate income taxes	-	-	(6,724)	-	-	(4,819)	-	(727)	(12,270)
Interest expense	-	-	-	-	-	-	-	(42,547)	(42,547)
Realized gain on derivative instruments	-	-	-	-	-	-	-	63,456	63,456
Realized foreign exchange gain	-	-	-	-	-	-	-	2,750	2,750
Realized other income	-	-	-	-	-	-	-	85	85
Fund flows from operations	93,148	91,245	50,338	1,205	44,893	56,660	(43)	23,763	361,209

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.

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

	Three Months Ended			Nine Months Ended	
($M)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Sep 30, 2016	Sep 30, 2015
Dividends declared	75,465	74,662	71,244	222,974	211,610
Shares issued for the DRIP[1]	(50,912)	(50,516)	(44,590)	(149,418)	(108,269)
Net dividends	24,553	24,146	26,654	73,556	103,341
Drilling and development	41,039	71,296	93,381	175,108	357,865
Exploration and evaluation	-	418	-	418	-
Asset retirement obligations settled	2,066	2,200	2,123	6,290	6,448
Payout	67,658	98,060	122,158	255,372	467,654

[1] DRIP Refers to Vermilion's dividend reinvestment and Premium Dividend™ plans.

	As at		
('000s of shares)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015
Shares outstanding	117,386	116,173	110,818
Potential shares issuable pursuant to the VIP	2,797	2,775	2,825
Diluted shares outstanding	120,183	118,948	113,643

CONSOLIDATED BALANCE SHEET
(THOUSANDS OF CANADIAN DOLLARS, UNAUDITED)

	Note	September 30, 2016	December 31, 2015
ASSETS			
Current			
Cash and cash equivalents		21,417	41,676
Accounts receivable		145,143	160,499
Crude oil inventory		12,166	13,079
Derivative instruments		20,138	55,214
Prepaid expenses		16,363	14,310
		215,227	284,778
Derivative instruments		3,991	13,128
Deferred taxes	6	147,682	135,753
Exploration and evaluation assets	3	281,839	308,192
Capital assets	2	3,266,678	3,467,369
		3,915,417	4,209,220
LIABILITIES			
Current			
Accounts payable and accrued liabilities		175,754	248,747
Current portion of long-term debt	5	-	224,901
Dividends payable	7	25,238	24,077
Derivative instruments		12,031	-
Income taxes payable		33,475	6,006
		246,498	503,731
Derivative instruments		6,806	-
Long-term debt	5	1,312,652	1,162,998
Finance lease obligation		21,357	23,565
Asset retirement obligations	4	344,008	305,613
Deferred taxes		335,159	354,654
		2,266,480	2,350,561
SHAREHOLDERS' EQUITY			
Shareholders' capital	7	2,407,595	2,181,089
Contributed surplus		83,846	107,946
Accumulated other comprehensive income		83,754	113,647
Deficit		(926,258)	(544,023)
		1,648,937	1,858,659
		3,915,417	4,209,220

APPROVED BY THE BOARD

(Signed "Catherine L. Williams")

Catherine L. Williams, Director

(Signed "Anthony Marino")

Anthony Marino, Director

CONSOLIDATED STATEMENTS OF NET LOSS AND COMPREHENSIVE INCOME (LOSS)
(THOUSANDS OF CANADIAN DOLLARS, EXCEPT SHARE AND PER SHARE AMOUNTS, UNAUDITED)

		Three Months Ended		Nine Months Ended	
	Note	Sep 30, 2016	Sep 30, 2015	Sep 30, 2016	Sep 30, 2015
REVENUE					
Petroleum and natural gas sales		232,660	245,051	622,900	705,267
Royalties		(12,969)	(17,100)	(39,285)	(49,635)
Petroleum and natural gas revenue		219,691	227,951	583,615	655,632
EXPENSES					
Operating		54,825	57,826	162,569	160,293
Transportation		9,696	11,090	29,946	31,513
Equity based compensation	8	15,642	16,773	49,746	53,699
Gain on derivative instruments		(13,864)	(42,874)	(406)	(36,347)
Interest expense		14,150	15,420	42,547	43,268
General and administration		12,295	13,088	41,365	41,153
Foreign exchange gain		(4,972)	(15,267)	(4,415)	(16,019)
Other expense (income)		106	82	46	(31,654)
Accretion	4	6,341	6,199	18,475	17,587
Depletion and depreciation	2, 3	143,556	148,843	401,147	350,946
Impairment	2	-	143,000	14,762	143,000
		237,775	354,180	755,782	757,439
LOSS BEFORE INCOME TAXES		(18,084)	(126,229)	(172,167)	(101,807)
INCOME TAXES					
Deferred	6	(6,883)	(55,401)	(28,418)	(79,759)
Current		3,274	12,482	12,270	53,174
		(3,609)	(42,919)	(16,148)	(26,585)
NET LOSS		(14,475)	(83,310)	(156,019)	(75,222)
OTHER COMPREHENSIVE INCOME (LOSS)					
Currency translation adjustments		38,963	101,923	(29,893)	89,332
COMPREHENSIVE INCOME (LOSS)		24,488	18,613	(185,912)	14,110
NET LOSS PER SHARE					
Basic		(0.12)	(0.76)	(1.36)	(0.69)
Diluted		(0.12)	(0.76)	(1.36)	(0.69)
WEIGHTED AVERAGE SHARES OUTSTANDING ('000s)					
Basic		116,814	110,293	114,975	109,052
Diluted		116,814	110,293	114,975	109,052

CONSOLIDATED STATEMENTS OF CASH FLOWS
(THOUSANDS OF CANADIAN DOLLARS, UNAUDITED)

	Note	Three Months Ended Sep 30, 2016	Three Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2016	Nine Months Ended Sep 30, 2015
OPERATING					
Net loss		(14,475)	(83,310)	(156,019)	(75,222)
Adjustments:					
Accretion	4	6,341	6,199	18,475	17,587
Depletion and depreciation	2, 3	143,556	148,843	401,147	350,946
Impairment	2	-	143,000	14,762	143,000
Unrealized (gain) loss on derivative instruments		(332)	(32,020)	63,050	(16,155)
Equity based compensation		15,642	16,773	49,746	53,699
Unrealized foreign exchange gain		(2,899)	(14,958)	(1,665)	(15,144)
Unrealized other expense		24	309	131	774
Deferred taxes	6	(6,883)	(55,401)	(28,418)	(79,759)
Asset retirement obligations settled	4	(2,066)	(2,123)	(6,290)	(6,448)
Changes in non-cash operating working capital		12,818	(5,082)	(5,662)	(93,733)
Cash flows from operating activities		151,726	122,230	349,257	279,545
INVESTING					
Drilling and development	2	(41,039)	(93,381)	(175,108)	(357,865)
Exploration and evaluation	3	-	-	(418)	-
Property acquisitions	2, 3	(10,391)	(22,155)	(19,811)	(22,670)
Changes in non-cash investing working capital		(15,715)	646	(18,325)	(26,516)
Cash flows used in investing activities		(67,145)	(114,890)	(213,662)	(407,051)
FINANCING					
(Decrease) increase in long-term debt		(44,138)	63,328	147,529	251,189
Repayment of senior unsecured notes	5	-	-	(225,000)	-
Decrease in finance lease obligation		(1,112)	(1,297)	(3,005)	(1,297)
Cash dividends		(24,291)	(26,437)	(72,395)	(102,586)
Cash flows (used in) from financing activities		(69,541)	35,594	(152,871)	147,306
Foreign exchange gain (loss) on cash held in foreign currencies		1,182	7,844	(2,983)	8,611
Net change in cash and cash equivalents		16,222	50,778	(20,259)	28,411
Cash and cash equivalents, beginning of period		5,195	98,038	41,676	120,405
Cash and cash equivalents, end of period		21,417	148,816	21,417	148,816
Supplementary information for cash flows from operating activities					
Interest paid		8,628	18,464	49,353	49,219
Income taxes (refunded) paid		(9,968)	19,501	(15,447)	78,329

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(THOUSANDS OF CANADIAN DOLLARS, UNAUDITED)

		Nine Months Ended	
	Note	Sep 30, 2016	Sep 30, 2015
SHAREHOLDERS' CAPITAL			
Balance, beginning of period		2,181,089	1,959,021
Equity based compensation	8	6,700	1,658
Shares issued for the DRIP [1]		149,418	108,269
Vesting of equity based awards		67,146	56,855
Share-settled dividends on vested equity based awards		3,242	7,561
Balance, end of period	7	2,407,595	2,133,364
CONTRIBUTED SURPLUS			
Balance, beginning of period		107,946	92,188
Equity based compensation	8	43,046	52,041
Vesting of equity based awards		(67,146)	(56,855)
Balance, end of period		83,846	87,374
ACCUMULATED OTHER COMPREHENSIVE INCOME			
Balance, beginning of period		113,647	5,722
Currency translation adjustments		(29,893)	89,332
Balance, end of period		83,754	95,054
DEFICIT			
Balance, beginning of period		(544,023)	(35,585)
Net loss		(156,019)	(75,222)
Dividends declared	7	(222,974)	(211,610)
Share-settled dividends on vested equity based awards		(3,242)	(7,561)
Balance, end of period		(926,258)	(329,978)
TOTAL SHAREHOLDERS' EQUITY		1,648,937	1,985,814

[1] DRIP Refers to Vermilion's dividend reinvestment and Premium Dividend™ plans.

NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2016 AND 2015
(TABULAR AMOUNTS IN THOUSANDS OF CANADIAN DOLLARS, EXCEPT SHARE AND PER SHARE AMOUNTS, UNAUDITED)

1. BASIS OF PRESENTATION

Vermilion Energy Inc. (the "Company" or "Vermilion") is a corporation governed by the laws of the Province of Alberta and is actively engaged in the business of crude oil and natural gas exploration, development, acquisition and production.

These condensed consolidated interim financial statements are in compliance with International Accounting Standard ("IAS") 34, "Interim financial reporting" and have been prepared using the same accounting policies and methods of computation as Vermilion's consolidated financial statements for the year ended December 31, 2015.

These condensed consolidated interim financial statements should be read in conjunction with Vermilion's consolidated financial statements for the year ended December 31, 2015, which are contained within Vermilion's Annual Report for the year ended December 31, 2015 and are available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

These condensed consolidated interim financial statements were approved and authorized for issuance by the Board of Directors of Vermilion on October 28, 2016.

2. CAPITAL ASSETS

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

($M)	Capital Assets
Balance at December 31, 2015	3,467,369
Additions	175,108
Property acquisitions	17,489
Changes in estimate for asset retirement obligations	28,202
Depletion and depreciation	(372,343)
Recognition of finance lease asset	1,593
Impairment	(14,762)
Foreign exchange	(35,978)
Balance at September 30, 2016	3,266,678

Impairment

On a quarterly basis, Vermilion performs an assessment as to whether any cash generating units ("CGUs") have indicators of impairment. When indicators of impairment are identified, Vermilion measures the recoverable amount of the applicable CGU based on the higher of the estimated fair value less costs to sell and value in use as at the reporting date. The estimated recoverable amount takes into account commodity price forecasts, expected production, estimated costs and timing of development, and undeveloped land values.

As a result of declines in the European natural gas price forecast, which decreased expected cash flows, Vermilion recorded a non-cash impairment charge of $14.8 million in the Ireland segment for the nine months ended September 30, 2016. The recoverable amount of the CGU was determined using a value in use approach based on forecasted reserves and expected cash flows and an after-tax discount rate of 9%.

The determination of impairment is sensitive to changes in key judgments, including reserve revisions, changes in forward commodity prices and exchange rates, and changes in costs and timing of development. Changes in these key judgments would impact the recoverable amount of CGUs, therefore resulting in additional impairment charges or recoveries. For the nine months ended September 30, 2016, a one percent increase in the assumed discount rate on expected cash flows of the Ireland CGU would result in no additional impairment, and a five percent decrease in forward commodity prices would result in an additional impairment of $11.0 million.

The following table outlines the forward commodity price estimates that were used in the calculation of the recoverable amount:

	Forward Commodity Price Assumptions (1)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025 (2)
NBP (€/mmbtu)	4.35	4.80	5.51	5.91	6.05	6.17	6.28	6.40	6.52	6.63

(1) Source: Average of GLJ Petroleum Consultants and Sproule price forecasts, effective October 1, 2016.
(2) Escalated at 1.75% per year thereafter.

3. EXPLORATION AND EVALUATION ASSETS

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

($M)	Exploration and Evaluation Assets
Balance at December 31, 2015	308,192
Additions	418
Changes in estimate for asset retirement obligations	20
Property acquisitions	2,322
Depreciation	(28,177)
Foreign exchange	(936)
Balance at September 30, 2016	281,839

4. ASSET RETIREMENT OBLIGATIONS

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

($M)	Asset Retirement Obligations
Balance at December 31, 2015	305,613
Additional obligations recognized	760
Obligations settled	(6,290)
Accretion	18,475
Changes in discount rates	27,462
Foreign exchange	(2,012)
Balance at September 30, 2016	344,008

5. LONG-TERM DEBT

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

	As at	
($M)	Sep 30, 2016	Dec 31, 2015
Revolving credit facility	1,312,652	1,162,998
Senior unsecured notes (1)	-	224,901
Long-term debt	1,312,652	1,387,899

(1) The senior unsecured notes, which had a principal balance of $225.0 million and matured and were repaid on February 10, 2016, were included in the current portion of long-term debt as at December 31, 2015.

Revolving Credit Facility

At September 30, 2016, Vermilion had in place a bank revolving credit facility totalling $2 billion, of which approximately $1.31 billion was drawn. The facility, which matures on May 31, 2019, is fully revolving up to the date of maturity.

The facility is extendable from time to time, but not more than once per year, for a period not longer than four years, at the option of the lenders and upon notice from Vermilion. If no extension is granted by the lenders, the amounts owing pursuant to the facility are due at the maturity date. This facility bears interest at a rate applicable to demand loans plus applicable margins. For the nine months ended September 30, 2016, the interest rate on the revolving credit facility was approximately 3.5% (2015 – 3.1%).

The amount available to Vermilion under this facility is reduced by certain outstanding letters of credit associated with Vermilion's operations totalling $21.0 million as at September 30, 2016 (December 31, 2015 - $25.2 million).

The facility is secured by various fixed and floating charges against the subsidiaries of Vermilion. As at September 30, 2016, Vermilion was in compliance with all financial covenants. These financial covenants required Vermilion to maintain:

- A ratio of total debt (defined as amounts classified as "Long-term debt", "Current portion of long term debt", and "Finance lease obligation" on the balance sheet), to consolidated net earnings before interest, income taxes, depreciation, accretion and other certain non-cash items (defined as consolidated EBITDA) of not greater than 4.0.
- A ratio of consolidated total senior debt (defined as consolidated total debt excluding unsecured and subordinated debt) to total capitalization (defined as amounts classified as "Shareholders' equity" on the balance sheet plus consolidated total senior debt as defined above) of not greater than 55%.

6. DEFERRED INCOME TAXES

For the nine months ended September 30, 2016, Vermilion de-recognized $34.1 million (year ended December 31, 2015 - $51.7 million) of deferred tax assets, relating to certain non-capital losses for which there is uncertainty as to the Company's ability to fully utilize such losses when applying forecasted commodity prices in effect as at September 30, 2016.

7. SHAREHOLDERS' CAPITAL

The following table reconciles the change in Vermilion's 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	3,823	149,418
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	165	6,700
Balance as at September 30, 2016	117,386	2,407,595

Dividends declared to shareholders for the nine months ended September 30, 2016 were $223.0 million (2015 - $211.6 million).

Subsequent to the end of the period and prior to the condensed consolidated interim financial statements being authorized for issue, Vermilion declared dividends totalling $25.3 million or $0.215 per share.

8. EQUITY BASED COMPENSATION

The following table summarizes the number of awards outstanding under the Vermilion Incentive Plan ("VIP"):

Number of Awards ('000s)	2016
Opening balance	1,711
Granted	763
Vested	(628)
Modified	11
Forfeited	(127)
Closing balance	1,730

9. SEGMENTED INFORMATION

Vermilion's operating activities in each business unit relate solely to the exploration, development and production of petroleum and natural gas. Vermilion has a Corporate head office located in Calgary, Alberta. Costs incurred in the Corporate segment relate to Vermilion's global hedging program and expenses incurred in financing and managing the Company's operating business units and expenditures relating to Vermilion's activities in Central and Eastern Europe.

The following table shows the fund flows from operations generated by each of Vermilion's business units. Fund flows from operations is a measure of profit or loss regularly provided to Vermilion's chief operating decision maker. Fund flows from operations provides a measure of each business unit's profitability and, correspondingly, its ability to pay dividends, fund asset retirement obligations, and make capital investments.

	Three Months Ended September 30, 2016								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Drilling and development	10,421	11,110	6,441	978	2,416	6,908	2,765	-	41,039
Oil and gas sales to external customers	64,453	65,221	23,470	6,783	26,065	44,835	1,833	-	232,660
Royalties	(4,817)	(7,069)	(312)	(246)	-	-	(525)	-	(12,969)
Revenue from external customers	59,636	58,152	23,158	6,537	26,065	44,835	1,308	-	219,691
Transportation	(3,978)	(3,586)	-	(556)	(1,576)	-	-	-	(9,696)
Operating	(15,579)	(12,933)	(4,854)	(3,321)	(4,695)	(13,011)	(432)	-	(54,825)
General and administration	(3,010)	(4,590)	633	(1,657)	(955)	(1,289)	(918)	(509)	(12,295)
PRRT	-	-	-	-	-	272	-	-	272
Corporate income taxes	-	955	(1,264)	-	-	(2,916)	-	(321)	(3,546)
Interest expense	-	-	-	-	-	-	-	(14,150)	(14,150)
Realized gain on derivative instruments	-	-	-	-	-	-	-	13,532	13,532
Realized foreign exchange gain	-	-	-	-	-	-	-	2,073	2,073
Realized other expense	-	-	-	-	-	-	-	(82)	(82)
Fund flows from operations	37,069	37,998	17,673	1,003	18,839	27,891	(42)	543	140,974

	Three Months Ended September 30, 2015								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Drilling and development	37,224	17,369	5,297	1,605	20,694	7,966	3,226	-	93,381
Oil and gas sales to external customers	77,493	76,552	41,083	9,523	-	39,325	1,075	-	245,051
Royalties	(6,638)	(8,038)	(638)	(1,477)	-	-	(309)	-	(17,100)
Revenue from external customers	70,855	68,514	40,445	8,046	-	39,325	766	-	227,951
Transportation	(4,131)	(4,566)	-	(627)	(1,766)	-	-	-	(11,090)
Operating	(23,877)	(11,998)	(5,243)	(2,796)	-	(13,766)	(146)	-	(57,826)
General and administration	(3,694)	(5,338)	(2,154)	(1,311)	(663)	(1,391)	(896)	2,359	(13,088)
PRRT	-	-	-	-	-	(99)	-	-	(99)
Corporate income taxes	-	(4,696)	(4,487)	-	-	(2,720)	-	(480)	(12,383)
Interest expense	-	-	-	-	-	-	-	(15,420)	(15,420)
Realized gain on derivative instruments	-	-	-	-	-	-	-	10,854	10,854
Realized foreign exchange gain	-	-	-	-	-	-	-	309	309
Realized other income	-	-	-	-	-	-	-	227	227
Fund flows from operations	39,153	41,916	28,561	3,312	(2,429)	21,349	(276)	(2,151)	129,435

($M)	Nine Months Ended September 30, 2016 Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Total assets	1,507,693	816,731	186,524	154,699	807,534	258,257	54,953	129,026	3,915,417
Drilling and development	45,811	37,345	18,003	2,109	7,664	54,674	9,502	-	175,108
Exploration and evaluation	-	-	-	-	-	-	-	418	418
Oil and gas sales to external customers	182,294	174,937	74,729	20,755	66,429	98,483	5,273	-	622,900
Royalties	(14,085)	(20,399)	(1,168)	(2,077)	-	-	(1,556)	-	(39,285)
Revenue from external customers	168,209	154,538	73,561	18,678	66,429	98,483	3,717	-	583,615
Transportation	(11,888)	(10,775)	-	(2,494)	(4,789)	-	-	-	(29,946)
Operating	(53,382)	(38,518)	(15,136)	(8,420)	(13,498)	(32,602)	(1,013)	-	(162,569)
General and administration	(9,791)	(14,000)	(1,363)	(6,559)	(3,249)	(4,402)	(2,747)	746	(41,365)
PRRT	-	-	-	-	-	-	-	-	-
Corporate income taxes	-	-	(6,724)	-	-	(4,819)	-	(727)	(12,270)
Interest expense	-	-	-	-	-	-	-	(42,547)	(42,547)
Realized gain on derivative instruments	-	-	-	-	-	-	-	63,456	63,456
Realized foreign exchange gain	-	-	-	-	-	-	-	2,750	2,750
Realized other income	-	-	-	-	-	-	-	85	85
Fund flows from operations	93,148	91,245	50,338	1,205	44,893	56,660	(43)	23,763	361,209

($M)	Nine Months Ended September 30, 2015 Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Total assets	1,769,222	902,777	219,221	172,664	947,592	223,261	36,955	231,009	4,502,701
Drilling and development	173,954	68,180	28,515	5,804	53,916	20,889	6,607	-	357,865
Oil and gas sales to external customers	246,661	218,011	91,814	31,544	-	114,813	2,424	-	705,267
Royalties	(20,998)	(19,760)	(2,858)	(5,313)	-	-	(706)	-	(49,635)
Revenue from external customers	225,663	198,251	88,956	26,231	-	114,813	1,718	-	655,632
Transportation	(12,542)	(11,103)	-	(2,761)	(5,107)	-	-	-	(31,513)
Operating	(64,510)	(34,926)	(16,483)	(6,168)	-	(37,735)	(471)	-	(160,293)
General and administration	(13,219)	(15,323)	(3,345)	(4,354)	(1,803)	(3,986)	(2,939)	3,816	(41,153)
PRRT	-	-	-	-	-	(5,824)	-	-	(5,824)
Corporate income taxes	-	(28,293)	(9,222)	-	-	(8,431)	-	(1,404)	(47,350)
Interest expense	-	-	-	-	-	-	-	(43,268)	(43,268)
Realized gain on derivative instruments	-	-	-	-	-	-	-	20,192	20,192
Realized foreign exchange gain	-	-	-	-	-	-	-	875	875
Realized other income	-	31,775	-	-	-	-	-	653	32,428
Fund flows from operations	135,392	140,381	59,906	12,948	(6,910)	58,837	(1,692)	(19,136)	379,726

Reconciliation of fund flows from operations to net loss

	Three Months Ended		Nine Months Ended	
($M)	Sep 30, 2016	Sep 30, 2015	Sep 30, 2016	Sep 30, 2015
Fund flows from operations	140,974	129,435	361,209	379,726
Equity based compensation	(15,642)	(16,773)	(49,746)	(53,699)
Unrealized gain (loss) on derivative instruments	332	32,020	(63,050)	16,155
Unrealized foreign exchange gain	2,899	14,958	1,665	15,144
Unrealized other expense	(24)	(309)	(131)	(774)
Accretion	(6,341)	(6,199)	(18,475)	(17,587)
Depletion and depreciation	(143,556)	(148,843)	(401,147)	(350,946)
Deferred taxes	6,883	55,401	28,418	79,759
Impairment	-	(143,000)	(14,762)	(143,000)
Net loss	(14,475)	(83,310)	(156,019)	(75,222)

10. CAPITAL DISCLOSURES

	Three Months Ended		Nine Months Ended	
($M except as indicated)	Sep 30, 2016	Sep 30, 2015	Sep 30, 2016	Sep 30, 2015
Long-term debt	1,312,652	1,270,154	1,312,652	1,270,154
Current liabilities	246,498	474,885	246,498	474,885
Current assets	(215,227)	(381,996)	(215,227)	(381,996)
Net debt [1]	1,343,923	1,363,043	1,343,923	1,363,043
Fund flows from operations	140,974	129,435	361,209	379,726
Annualized fund flows from operations [2]	563,896	517,740	481,612	506,301
Ratio of net debt to annualized fund flows from operations ([1] ÷ [2])	2.4	2.6	2.8	2.7

The ratio of net debt to annualized fund flows from operations increased to 2.8 times for the nine months ended September 30, 2016 primarily as a result of declines in commodity prices, which decreased annualized fund flows from operations.

11. FINANCIAL INSTRUMENTS

Determination of Fair Values

The level in the fair value hierarchy into which the fair value measurements are categorized is determined on the basis of the lowest level input that is significant to the fair value measurement. Transfers between levels on the fair value hierarchy are deemed to have occurred at the end of the reporting period.
Level 1 – Fair value measurement is determined by reference to unadjusted quoted prices in active markets for identical assets or liabilities.
Level 2 – Fair value measurement is determined based on inputs other than unadjusted quoted prices that are observable, either directly or indirectly.
Level 3 – Fair value measurement is based on inputs for the asset or liability that are not based on observable market data.
Cash and cash equivalents are classified as Level 1 measurements. Receivables and payables approximate their value due to the short-term nature of those instruments. The fair value of long-term debt on the revolving credit facility approximates carrying value due to the use of short-term borrowing instruments at market rates of interest.
Derivative assets and derivative liabilities are classified as Level 2 measurements. The fair value for derivative assets and derivative liabilities are determined using pricing models incorporating future prices that are based on assumptions which are supported by prices from observable market transactions and are adjusted for credit risk.
Vermilion does not have any financial instruments classified as Level 3 measurements.

Nature and Extent of Risks Arising from Financial Instruments

Market risk:
Vermilion's financial instruments are exposed to currency risk related to changes in foreign currency denominated financial instruments and commodity price risk related to outstanding derivatives. The following table summarizes the impact on comprehensive income before tax for the nine months ended September 30, 2016 given changes in the relevant risk variables that Vermilion considers reasonably possible at the balance sheet date. The impact on comprehensive income before tax associated with changes in these risk variables for assets and liabilities that are not considered financial instruments are excluded from this analysis. This analysis does not attempt to reflect any interdependencies between the relevant risk variables.

Risk ($M)	Description of change in risk variable	Before tax effect on comprehensive income - increase (decrease) Sep 30, 2016
Currency risk - Euro to Canadian	5% **increase** in strength of the Canadian dollar against the Euro	(2,128)
	5% **decrease** in strength of the Canadian dollar against the Euro	2,128
Currency risk - US $ to Canadian	5% **increase** in strength of the Canadian dollar against the US $	(57,992)
	5% **decrease** in strength of the Canadian dollar against the US $	57,992
Commodity price risk	US $5.00/bbl **increase** in crude oil price used to determine the fair value of derivatives	(2,600)
	US $5.00/bbl **decrease** in crude oil price used to determine the fair value of derivatives	6,615
	€ 0.5/GJ **increase** in European natural gas price used to determine the fair value of derivatives	(26,545)
	€ 0.5/GJ **decrease** in European natural gas price used to determine the fair value of derivatives	23,923
Interest rate risk	1% **increase** in average Canadian prime interest rate	(8,552)
	1% **decrease** in average Canadian prime interest rate	8,552

The above table shows the before tax effect on comprehensive income for a 5% change in the US dollar to Canadian dollar exchange rate based on derivative instruments, long-term debt, and other financial instruments as at September 30, 2016. The $58.0 million increase or decrease shown above is primarily driven by US $0.9 billion notional of cross currency interest rate swaps outstanding as at September 30, 2016 and effective for October 2016.

Subsequent to September 30, 2016, Vermilion repaid $1.1 billion of borrowings on the revolving credit facility bearing interest at CDOR plus applicable margins and simultaneously borrowed US $0.9 billion on the revolving credit facility bearing interest at LIBOR plus applicable margins. As this transaction occurred subsequent to the balance sheet date, it is not included in the calculations shown in the above table.

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

Robert Michaleski
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

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

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

JPMorgan Chase Bank, N.A., Toronto Branch

Union Bank, Canada Branch

Barclays Bank PLC

Canadian Western Bank

Goldman Sachs Lending Partners LLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

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

INVESTOR RELATIONS CONTACT

Kyle Preston
Director Investor Relations
403-476-8431 TEL
403-476-8100 FAX
1-866-895-8101 IR TOLL FREE
investor_relations@vermilionenergy.com

EXCELLENCE

We aim for exceptional
results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

VERMILION ENERGY

Vermilion Energy Inc.
3500, 520 3rd Avenue SW
Calgary, Alberta T2P 0R3

Telephone: 1.403.269.4884
Facsimile: 1.403.476.8100
IR Toll Free: 1.866.895.8101
investor_relations@vermilionenergy.com

vermilionenergy.com