VERMILION ENERGY

Vermilion Energy Inc.

2014 Third Quarter Management's Discussion & Analysis

DEFINED PRODUCTION GROWTH
RELIABLE & GROWING DIVIDENDS

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 present value of future net cash flows from such reserves; petroleum and natural gas sales; future production levels (including the timing thereof) and rates of average annual production growth; estimated contingent resources and prospective resources; 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; the timing of regulatory proceedings and approvals; and the timing of first commercial natural gas and the estimate of Vermilion’s share of the expected natural gas production from the Corrib field.

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.

All oil and natural gas reserve information contained in this document has been prepared and presented in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. The actual oil and natural gas reserves and future production will be greater than or less than the estimates provided in this document. The estimated future net revenue from the production of oil and natural gas reserves does not represent the fair market value of these reserves.

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A"), dated November 6, 2014, of Vermilion Energy Inc.'s ("Vermilion" or the "Company") operating and financial results as at and for the three and nine months ended September 30, 2014 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, 2014 and the audited consolidated financial statements for the year ended December 31, 2013 and 2012, 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, 2014 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 measures which do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS"). As such, these financial measures are considered additional GAAP or non-GAAP financial measures and therefore are unlikely to be comparable with similar financial measures presented by other issuers. These additional GAAP and non-GAAP financial measures include:

- Fund flows from operations: This additional GAAP financial measure is calculated as cash flows from operating activities before changes in non-cash operating working capital and asset retirement obligations settled. 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 cash necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.
- Netbacks: These non-GAAP financial measures are per boe and per mcf 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 third party crude oil and natural gas producers.

For a full description of these and other non-GAAP financial measures and a reconciliation of these measures to their most directly comparable GAAP measures, please refer to "ADDITIONAL AND NON-GAAP FINANCIAL MEASURES".

VERMILION'S BUSINESS

Vermilion is a Calgary, Alberta based international oil and gas producer focused on the acquisition, development and optimization of producing properties in Western Canada, Europe, and Australia. We manage our business through our Calgary head office and our international business unit offices.

This MD&A separately discusses each of our business units in addition to our corporate segment.

- Canada business unit: Relates to our assets in Alberta and Saskatchewan.
- France business unit: Relates to our operations in France in the Paris and Aquitaine Basins.
- Netherlands business unit: Relates to our operations in the Netherlands.
- Germany business unit: Relates to our 25% contractual participation interest in a four-partner consortium in Germany.
- Ireland business unit: Relates to our 18.5% non-operated interest in the offshore Corrib natural gas field.
- Australia business unit: Relates to our operations in the Wandoo offshore crude oil field.
- Corporate: Includes expenditures related to our global hedging program, financing expenses, and general and administration expenses, primarily incurred in Canada and not directly related to the operations of a specific business unit.

Prior to December 31, 2013, Vermilion combined the operating and financial results of the Canada business unit and the Corporate segment and presented the combined results as Canada.

GUIDANCE

We first issued 2014 capital expenditure guidance of $555 million on November 7, 2013. We subsequently increased our 2014 capital expenditure guidance to $590 million on March 18, 2014, to reflect an additional $35 million of 2014 development capital expected to be incurred in association with our acquisition of Elkhorn Resources Inc. Concurrent with the release of our first quarter 2014 financial and operating results on May 2, 2014, we further updated our 2014 capital expenditure guidance to $635 million, reflecting the expected full-year rise in the cost to Vermilion, in Canadian dollar terms, of both actual and anticipated international capital expenditures as a result of the devaluation of the Canadian dollar against both the U.S. dollar and the Euro, and the addition of approximately $15 million of anticipated spending associated with drilling activities. We also increased our original production guidance from 47,500-48,500 boe/d to 48,000-49,000 boe/d.

Based on the continued strength of our operations during the second quarter of 2014, we further increased our full-year 2014 production and capital expenditure guidance to 48,500-49,500 boe/d and $650 million, respectively. The increase in capital expenditures was attributed to increased Mannville development drilling and higher than anticipated costs associated with the Duvernay development program.

We are further revising our 2014 full year production guidance from the previous range of 48,500-49,500 boe/d to a range of 49,000-49,500 boe/d and currently expect to achieve production near the upper end of this refined range for 2014.

The following table summarizes our 2014 guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2014 Guidance	November 7, 2013	555	45,000 to 46,000
2014 Guidance - Update	March 18, 2014	590	47,500 to 48,500
2014 Guidance - Update	May 2, 2014	635	48,000 to 49,000
2014 Guidance - Update	July 31, 2014	650	48,500 to 49,500
2014 Guidance - Update	November 10, 2014	650	49,000 to 49,500

SHAREHOLDER RETURN

Vermilion strives to provide investors with reliable and growing dividends in addition to sustainable, global production growth. The following table, as of September 30, 2014, reflects our trailing one, three, and five year performance:

Total return (1)	Trailing One Year	Trailing Three Year	Trailing Five Year
Dividends per Vermilion share	$2.54	$7.19	$11.75
Capital appreciation per Vermilion share	$11.56	$24.14	$38.60
Total return per Vermilion share	24.9%	71.1%	170.2%
Annualized total return per Vermilion share	24.9%	19.6%	22.0%
Annualized total return on the S&P TSX High Income Energy Index	13.2%	7.6%	7.5%

(1) The above table includes non-GAAP financial measures which may not be comparable to other companies. Please see the “ADDITIONAL AND NON-GAAP FINANCIAL MEASURES” section of this MD&A.

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change		Nine Months Ended		% change
	Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	Q3/14 vs. Q2/14	Q3/14 vs. Q3/13	Sep 30, 2014	Sep 30, 2013	2014 vs. 2013
Production								
Crude oil (bbls/d)	**29,147**	30,184	26,664	(3%)	9%	**28,890**	25,640	13%
NGLs (bbls/d)	**2,354**	2,892	1,945	(19%)	21%	**2,463**	1,719	43%
Natural gas (mmcf/d)	**110.52**	114.08	77.41	(3%)	43%	**109.33**	81.97	33%
Total (boe/d)	**49,920**	52,089	41,510	(4%)	20%	**49,574**	41,020	21%
Build (draw) in inventory (mbbl)	**104**	67	20			**74**	(218)	
Financial metrics								
Fund flows from operations ($M)	**197,898**	216,076	165,645	(8%)	19%	**619,337**	503,866	23%
Per share ($/basic share)	**1.85**	2.05	1.63	(10%)	13%	**5.90**	5.01	18%
Net earnings ($M)	**53,903**	53,993	67,796	-	(20%)	**210,684**	226,131	(7%)
Per share ($/basic share)	**0.50**	0.51	0.67	(2%)	(25%)	**2.01**	2.25	(11%)
Cash flows from operating activities ($M)	**235,010**	149,592	158,236	57%	49%	**562,840**	528,022	7%
Net debt ($M)	**1,243,438**	1,168,998	700,286	6%	78%	**1,243,438**	700,286	78%
Cash dividends ($/share)	**0.645**	0.645	0.600	-	8%	**1.935**	1.800	8%
Activity								
Capital expenditures ($M)	**190,033**	135,073	135,661	41%	40%	**521,481**	394,248	32%
Acquisitions ($M)	**40,847**	381,139	7,586	(89%)	438%	**600,213**	7,586	7,812%
Gross wells drilled	**26.00**	13.00	21.00			**63.00**	55.00	
Net wells drilled	**20.31**	6.72	16.26			**45.86**	47.62	

Operational review

- Recorded consolidated average production of 49,920 boe/d during Q3 2014, a 4% decrease as compared to Q2 2014. This decrease was primarily driven by a 7% quarter-over-quarter decrease in production in Canada following reduced activity during spring breakup in Q2 2014.
- Increased consolidated average production for the three and nine months ended September 30, 2014 by approximately 20% versus the comparable periods in 2013, primarily due to growth in Canada, the Netherlands, and incremental production from our acquisition in Germany. In Canada, production growth of 36% and 33% for the three and nine months ended September 30, 2014 versus the comparable periods in 2013 resulted from our continued development of the Cardium and Mannville plays in Alberta coupled with incremental production from southeast Saskatchewan following our acquisition in April 2014 of Elkhorn Resources Inc. (1,524 boe/d in the year-to-date period). In the Netherlands, production growth of 32% and 17% for the three and nine months ended September 30, 2014 versus the comparable periods in 2013 resulted from incremental production from our acquisition in the Netherlands in Q4 2013, increased volumes following completion of the Middenmeer Treatment Centre retrofit in the latter part of 2013, and ongoing recompletion and production optimization activities. These production increases were partially offset by decreased production in France due primarily to the temporary shut-in of natural gas production from the Vic Bilh field for the entirety of 2014.
- Activity during the quarter included capital expenditures totalling $190.0 million, incurred primarily in Canada, France, and Ireland. In Canada, capital expenditures totalling $97.4 million were significantly higher than the $37.0 million incurred in Q2 2014 and related to the drilling of 16.86 net wells (3.29 net wells in Q2 2014), with activity influenced by spring breakup in Q2 2014. In France, capital expenditures of $35.1 million related to the drilling of 3.0 net wells in the Champotran field. In Ireland, $30.1 million of capital expenditures were incurred relating to various tunnel outfitting and offshore workover activities.
- Acquisition expenditures for the quarter totalling $40.8 million related to our acquisition in the U.S. and crown land sales, primarily in southeast Saskatchewan, with the purchase of approximately 15,000 net acres.

Financial review

Net earnings

- Net earnings for Q3 2014 was $53.9 million ($0.50/basic share) as compared to $54.0 million ($0.51/basic share) for Q2 2014. Quarter-over-quarter net earnings were relatively consistent as lower petroleum and natural gas sales ("sales") and operating income were offset by gains on derivative instruments (including $7.8 million of unrealized gains due to lower forecasted pricing for the remainder of 2014 and the impact on the valuation of our crude oil derivative positions) and lower unrealized foreign exchange losses. Unrealized foreign exchange losses primarily resulted from the weakening of the Euro versus the Canadian dollar and the resulting impact on our Euro denominated financial assets. In Q3 2014, the Euro weakened by 3% versus 4% in Q2 2014.
- Net earnings for the three and nine months ended September 30, 2014 were 20% and 7% lower versus the respective comparable periods in 2013. These decreases occurred despite significantly increased revenue due to the impact of the aforementioned unrealized foreign exchange losses, increased depletion expense associated with higher production, and higher deferred tax expense due to the utilization of tax losses in Canada.

Cash flows from operating activities

- Cash flow from operations increased by 49% and 7% for the three and nine months ended September 30, 2014 as compared to the same period in 2013. Both increases were the result of higher produced volumes and the resulting increase in fund flows from operations. For the nine months ended September 30, 2014, this increase in fund flows from operations was partially offset by timing differences pertaining to working capital balances.

Fund flows from operations

- Generated fund flows from operations of $197.9 million during Q3 2014, a decrease of $18.2 million (8%) versus Q2 2014. This quarter-over-quarter decrease was the result of lower sales partially offset by increased realized derivative gains and decreases in corporate income taxes. Lower sales were driven largely by weaker commodity pricing coupled with lower sold volumes in Canada and an inventory build in France, partially offset by increased sold volumes in Australia. Lower corporate income taxes was the result of lower taxable income resulting from decreased sales and revisions to the estimated 2014 effective tax rate in France.
- Fund flows from operations increased by 19% and 23% for the three and nine months ended September 30, 2014, respectively, versus the comparable periods in 2013. These increases were primarily the result of increased sales volumes in Canada and the Netherlands coupled with incremental production following our Q1 2014 acquisition in Germany, partially offset by a build in inventory in Australia for both the three and nine months ended September 30, 2014.

Net debt

- As a result of funding our 2014 acquisitions in Germany and Saskatchewan, net debt increased to $1.2 billion or 1.5 times annualized cash flow as at September 30, 2014.

Dividends

- Declared dividends of $0.215 per common share per month during 2014, totalling $0.645 per common share for the quarter and $1.935 per common share for the year-to-date period.

COMMODITY PRICES

	Three Months Ended			% change		Nine Months Ended		% change
	Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	Q3/14 vs. Q2/14	Q3/14 vs. Q3/13	Sep 30, 2014	Sep 30, 2013	2014 vs. 2013
Average reference prices								
WTI (US $/bbl)	**97.17**	102.99	105.82	(6%)	(8%)	**99.61**	98.14	1%
Edmonton Sweet index (US $/bbl)	**89.24**	96.85	101.10	(8%)	(12%)	**92.17**	93.03	(1%)
Dated Brent (US $/bbl)	**101.85**	109.63	110.37	(7%)	(8%)	**106.57**	108.45	(2%)
AECO ($/GJ)	**3.81**	4.44	2.31	(14%)	65%	**4.56**	2.89	58%
TTF ($/GJ)	**7.26**	7.91	9.94	(8%)	(27%)	**8.41**	10.17	(17%)
TTF (€/GJ)	**5.04**	5.27	7.20	(4%)	(30%)	**5.68**	7.53	(25%)
Average foreign currency exchange rates								
CDN $/US $	**1.09**	1.09	1.04	-	5%	**1.09**	1.02	7%
CDN $/Euro	**1.44**	1.50	1.38	(4%)	4%	**1.48**	1.35	10%
Average realized prices ($/boe)								
Canada	**64.85**	71.56	63.56	(9%)	2%	**68.58**	61.16	12%
France	**107.99**	117.29	107.08	(8%)	1%	**114.36**	104.29	10%
Netherlands	**45.73**	48.14	61.44	(5%)	(26%)	**52.80**	62.70	(16%)
Germany	**36.43**	45.36	-	(20%)	100%	**44.68**	-	100%
Australia	**119.07**	126.87	120.95	(6%)	(2%)	**124.59**	117.65	6%
Consolidated	**76.80**	82.96	86.10	(7%)	(11%)	**82.73**	83.10	-
Production mix (% of production)								
% priced with reference to WTI	**28%**	30%	24%			**27%**	24%	
% priced with reference to AECO	**18%**	18%	17%			**18%**	17%	
% priced with reference to TTF	**18%**	18%	14%			**18%**	16%	
% priced with reference to Dated Brent	**36%**	34%	45%			**37%**	43%	

Reference prices

- Weakening global oil fundamentals, marked by a growing supply surplus, prompted a decline in oil prices throughout Q3 2014. Averaging the quarter at US $101.85/bbl, Dated Brent was 7% lower quarter-over-quarter and 8% below the same period last year.
- WTI also suffered downward price pressure throughout Q3 2014 despite strong refining runs and averaged US $97.17/bbl or 6% lower than Q2 2014 and 8% lower year-over-year.
- AECO natural gas fell 14% quarter-over-quarter to average $3.81/GJ in Q3 2014. Even as seasonal factors weighed on prices on a quarter-over-quarter basis, low storage levels and relatively strong flows on export pipelines led prices up 65% year-over-year.
- European natural gas continued to weaken over the quarter as above-normal storage levels, LNG weakness and modest summer demand led prices lower by 8% quarter-over-quarter and 27% versus the same period last year.
- The Canadian dollar was relatively flat quarter-over-quarter but 5% weaker to the US dollar year-over-year.

Realized prices

- Consolidated realized price decreased by 7% for Q3 2014 as compared to Q2 2014 and 11% as compared to Q3 2013. These decreases were primarily the result of weaker commodity reference prices during Q3 2014 versus the comparable quarters.
- Consolidated realized price for the nine months ended September 30, 2014 was relatively unchanged versus the same period in 2013 as the impact of weaker TTF pricing was offset by stronger AECO pricing and a weaker Canadian dollar.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Nine Months Ended			
	Sep 30, 2014		Jun 30, 2014		Sep 30, 2013		Sep 30, 2014		Sep 30, 2013	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	**344,688**	**76.80**	387,684	82.96	327,185	86.10	**1,113,555**	**82.73**	948,727	83.10
Royalties	**(29,000)**	**(6.46)**	(29,013)	(6.21)	(18,730)	(4.93)	**(82,037)**	**(6.09)**	(50,320)	(4.41)
Petroleum and natural gas revenues	**315,688**	**70.34**	358,671	76.75	308,455	81.17	**1,031,518**	**76.64**	898,407	78.69
Transportation expense	**(10,979)**	**(2.45)**	(12,032)	(2.57)	(6,549)	(1.72)	**(32,872)**	**(2.44)**	(19,843)	(1.74)
Operating expense	**(56,227)**	**(12.53)**	(58,213)	(12.46)	(46,246)	(12.17)	**(172,426)**	**(12.81)**	(146,903)	(12.87)
General and administration	**(16,262)**	**(3.62)**	(17,762)	(3.80)	(12,033)	(3.17)	**(48,491)**	**(3.60)**	(35,956)	(3.15)
PRRT	**(13,834)**	**(3.08)**	(12,699)	(2.72)	(15,649)	(4.12)	**(46,772)**	**(3.47)**	(39,392)	(3.45)
Corporate income taxes	**(17,454)**	**(3.89)**	(32,635)	(6.98)	(46,453)	(12.22)	**(88,692)**	**(6.59)**	(118,729)	(10.40)
Interest expense	**(12,918)**	**(2.88)**	(12,334)	(2.64)	(10,109)	(2.66)	**(36,712)**	**(2.73)**	(28,134)	(2.46)
Realized gain (loss) on derivative instruments	**8,837**	**1.97**	2,419	0.52	(4,765)	(1.25)	**13,896**	**1.03**	(5,782)	(0.51)
Realized foreign exchange gain (loss)	**812**	**0.17**	587	0.12	(1,227)	(0.32)	**(642)**	**(0.05)**	(572)	(0.05)
Realized other income	**235**	**0.05**	74	0.02	221	0.06	**530**	**0.04**	770	0.07
Fund flows from operations	**197,898**	**44.08**	216,076	46.24	165,645	43.60	**619,337**	**46.02**	503,866	44.13

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

($M)	Q3/14 vs. Q2/14	Q3/14 vs. Q3/13	2014 vs. 2013
Fund flows from operations – Comparative period	**216,076**	**165,645**	**503,866**
Sales volume variance:			
Canada	(13,984)	38,597	101,499
France	(8,863)	(11,373)	(15,669)
Netherlands	(1,638)	8,838	16,748
Germany	(398)	8,591	28,603
Australia	9,052	(14,515)	(20,740)
Pricing variance on sold volumes:			
WTI	(9,583)	(8,722)	16,434
AECO	(840)	8,979	22,723
Dated Brent	(13,351)	(3,631)	33,703
TTF	(3,391)	(9,261)	(18,473)
Changes in:			
Royalties	13	(10,270)	(31,717)
Transportation	1,053	(4,430)	(13,029)
Operating expense	1,986	(9,981)	(25,523)
General and administration	1,500	(4,229)	(12,535)
PRRT	(1,135)	1,815	(7,380)
Corporate income taxes	15,181	28,999	30,037
Interest	(584)	(2,809)	(8,578)
Realized derivatives	6,418	13,602	19,678
Realized foreign exchange	225	2,039	(70)
Realized other income	161	14	(240)
Fund flows from operations – Current Period	**197,898**	**197,898**	**619,337**

Fund flows from operations of $197.9 million during Q3 2014 represented a decrease of $18.2 million (8%) versus Q2 2014. This quarter-over-quarter decrease was the result of a $43.0 million decrease in sales, partially offset by a $6.4 million increase in hedging proceeds (following weaker commodity prices during the quarter) and a $15.2 million decrease in corporate income taxes. The decrease in sales included $27.2 million of pricing variance due to a decrease in all relevant commodity prices and $15.8 million of sales volume variance due primarily to lower sales volumes in Canada (resulting from operational declines) and France (due to a build in inventory during Q3 2014), partially offset by higher produced and sold volumes in Australia. The decrease in corporate income taxes was due to lower taxable income resulting from decreased sales and revisions to the estimated 2014 effective tax rate in France.

On a year-over-year basis, fund flows from operations increased 19% and 23% for the three and nine months ended September 30, 2014, respectively, versus the comparable periods in 2013. These increases were primarily the result of favorable sales volume variances in Canada and the Netherlands coupled with incremental production following our Q1 2014 acquisition in Germany. These favorable sales volume variances were partially offset by a build in inventory in Australia. On a quarterly basis, the year-over-year change in fund flows from operations includes an unfavorable pricing variance of $12.6 million due to weaker crude oil and TTF pricing. For the nine months ended September 30, 2014 versus the same period in 2013, fund flows from operations includes a favorable variance of $54.4 million due to the impact of the weakening Canadian dollar on crude oil pricing coupled with stronger AECO natural gas pricing, offset partially by lower TTF pricing.

Fluctuations in fund flows from operations (and correspondingly net earnings and cash flows from operating activities) 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 highly 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 our balance sheet. When the crude oil inventory is subsequently drawn down, the related expenses are recognized in fund flows from operations.

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

Operational review

Canada business unit	Three Months Ended Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	% change Q3/14 vs. Q2/14	Q3/14 vs. Q3/13	Nine Months Ended Sep 30, 2014	Sep 30, 2013	% change 2014 vs. 2013
Production								
Crude oil (bbls/d)	**11,469**	12,676	7,969	(10%)	44%	**11,202**	8,274	35%
NGLs (bbls/d)	**2,291**	2,796	1,897	(18%)	21%	**2,387**	1,654	44%
Natural gas (mmcf/d)	**57.07**	57.59	43.40	(1%)	31%	**54.76**	42.72	28%
Total (boe/d)	**23,272**	25,070	17,099	(7%)	36%	**22,714**	17,047	33%
Production mix (% of total)								
Crude oil	**49%**	51%	47%			**49%**	49%	
NGLs	**10%**	11%	11%			**11%**	10%	
Natural gas	**41%**	38%	42%			**40%**	41%	
Activity								
Capital expenditures ($M)	**97,393**	36,968	62,270	163%	56%	**249,300**	163,952	52%
Acquisitions ($M)	**27,883**	381,326	7,586			**413,977**	7,586	
Gross wells drilled	**22.00**	9.00	21.00			**51.00**	48.00	
Net wells drilled	**16.86**	3.29	16.26			**35.12**	40.62	

Production

- Production in Canada of 23,272 boe/d during Q3 2014 represented a decrease of 7% quarter-over-quarter and an increase of 36% year-over-year. Year-to-date average production of 22,714 boe/d represents an increase of 33% versus the same period in 2013.
- Quarter-over-quarter decrease in production was largely due to the effect of lower activity levels during spring breakup.
- The strong year-over-year increase was primarily attributable to production additions from our southeast Saskatchewan acquisition. Production growth was further supplemented by strong volume additions from our Mannville and Cardium development programs over the same period.
- Cardium production averaged more than 10,600 boe/d in Q3 2014, and more than 11,000 boe/d year-to-date 2014.
- Mannville production averaged more than 3,700 boe/d in Q3 2014, and nearly 3,800 boe/d year-to-date 2014.
- Saskatchewan production averaged approximately 2,600 boe/d in Q3 2014, a 31% increase over the Q2 2014, taking into account an effective acquisition date of April 29, 2014.

Activity review

- Vermilion drilled a total of 16 (14.7 net) operated wells during Q3 2014.

  Cardium
  - We drilled five (4.5 net) operated wells and brought two (2.0 net) operated wells on production during Q3 2014. Year-to-date we have drilled 17 (16.0 net) operated wells and brought 20 (20.0 net) operated wells on production, of which 15 were long-reach wells with horizontal lengths greater than one mile.
  - Since 2009, we have drilled or participated in 264 (188.7 net) wells.
  - Operating netbacks have averaged approximately $67/boe year-to-date.
  - In 2014, we plan to drill or participate in approximately 40 (27.5 net) wells.

  Mannville
  - During Q3 2014, we drilled one (1.0 net) well. Year-to-date we have drilled six (4.7 net) operated wells and brought on production five (3.7 net) operated wells.
  - In 2014, we expect to drill or participate in up to 20 (11.4 net) wells.

  Duvernay
  - In Q2 2014, we drilled two (1.3 net) horizontal wells. One (0.3 net) well was completed in Q3 2014, and the other is anticipated to be completed in Q4 2014. The first well was brought on production subsequent to the third quarter and the second well is anticipated to be on production prior to year-end 2014.

  Saskatchewan
  - We drilled 10 (9.2 net) operated Midale wells in Saskatchewan and brought seven gross (6.3 net) operated wells on production during Q3 2014.
  - In 2014, we plan to drill or participate in 12 (10.4 net) Midale wells.

Financial review

	Three Months Ended			% change		Nine Months Ended		% change
Canada business unit ($M except as indicated)	**Sep 30, 2014**	**Jun 30, 2014**	**Sep 30, 2013**	**Q3/14 vs. Q2/14**	**Q3/14 vs. Q3/13**	**Sep 30, 2014**	**Sep 30, 2013**	**2014 vs. 2013**
Sales	**138,853**	163,261	100,000	(15%)	39%	**425,294**	284,638	49%
Royalties	**(19,034)**	(18,240)	(11,156)	4%	71%	**(49,937)**	(29,852)	67%
Transportation expense	**(4,048)**	(4,024)	(3,272)	1%	24%	**(11,170)**	(8,152)	37%
Operating expense	**(19,074)**	(21,179)	(12,770)	(10%)	49%	**(56,863)**	(42,586)	34%
General and administration	**(4,523)**	(6,560)	(3,484)	(31%)	30%	**(13,951)**	(10,501)	33%
Fund flows from operations	**92,174**	113,258	69,318	(19%)	33%	**293,373**	193,547	52%
Netbacks ($/boe)								
Sales	**64.85**	71.56	63.56	(9%)	2%	**68.58**	61.16	12%
Royalties	**(8.89)**	(7.99)	(7.09)	11%	25%	**(8.05)**	(6.41)	26%
Transportation expense	**(1.89)**	(1.76)	(2.08)	7%	(9%)	**(1.80)**	(1.75)	3%
Operating expense	**(8.91)**	(9.28)	(8.12)	(4%)	10%	**(9.17)**	(9.15)	-
General and administration	**(2.11)**	(2.88)	(2.21)	(27%)	(5%)	**(2.25)**	(2.26)	-
Fund flows from operations netback	**43.05**	49.65	44.06	(13%)	(2%)	**47.31**	41.59	14%
Reference prices								
WTI (US $/bbl)	**97.17**	102.99	105.82	(6%)	(8%)	**99.61**	98.14	1%
Edmonton Sweet index (US $/bbl)	**89.24**	96.85	101.10	(8%)	(12%)	**92.17**	93.03	(1%)
AECO ($/GJ)	**3.81**	4.44	2.31	(14%)	65%	**4.56**	2.89	58%

Sales

- The realized price for our crude oil production in Canada is directly linked to WTI but is subject to market conditions in Western Canada. These market conditions can result in fluctuations in the pricing differential, 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.
- Sales per boe decreased by 9% quarter-over-quarter as a result of an 8% decrease in Edmonton Sweet index pricing and a 14% decrease in AECO pricing. This decrease coupled with lower production volumes resulting from reduced activity over spring breakup resulted in a 15% decrease in sales.
- On a year-over-year basis, sales per boe increased by 2% and 12% for the three and nine months ended September 30, 2014 versus the same periods in 2013. Sales increased despite declining Edmonton Sweet index pricing due to higher AECO pricing and increased production mix towards crude oil and NGLs. These increases coupled with incremental production from our Saskatchewan acquisition and production growth in the Cardium and Mannville resource plays resulted in sales growth of 39% and 49% for the three and nine months ended September 30, 2014, respectively.

Royalties

- Royalty expense as a percentage of sales increased to 13.7% for Q3 2014 from 11.2% in both Q3 2013 and Q2 2014. Royalty expense as a percentage of sales increased to 11.7% for the year-to-date period ended Q3 2014 as compared to 10.5% for the same period of the prior year.
- The quarter-over-quarter increase is largely associated with wells coming off of incentive royalty rates after reaching specified production thresholds. In addition, the year-over-year increase in royalty rates as a percentage of sales is partially attributable to increased gas prices as well as slightly higher average royalty rates associated with Vermilion's Saskatchewan production.

Transportation

- Transportation expense relates to the delivery of crude oil and natural gas production to major pipelines where legal title transfers.
- Transportation expense per boe increased for the year-to-date period ended Q3 2014 as compared to the same period in the prior year due to trucking costs associated with Vermilion's recently acquired Saskatchewan assets as well as pipeline tariff increases.

Operating expense

- Operating expense per boe for Q3 2014 was slightly lower than the prior quarter due to favorable equalization adjustments received in the current quarter. The increase in operating expense per boe for the current quarter as compared to the same quarter in 2013 is attributable to higher operating expenses associated with the Saskatchewan properties Vermilion acquired in the second quarter of 2014. Year-to-date operating expense per boe is consistent with the prior year due to project timing, partially offset by the higher costs associated with Vermilion's Saskatchewan production.

General and administration

- General and administration expense decreased in the current quarter as compared to the prior quarter largely due to higher costs in the previous quarter related to the Saskatchewan acquisition including legal and consultant costs ($1.1MM) and additional salary allocations from our Corporate segment to our Canadian business unit associated with the integration process ($0.7MM).
- Year-over-year, the increase in general and administration expense is associated with incremental expense associated with the Saskatchewan acquisition, higher staffing levels and the timing of expenditures.

FRANCE BUSINESS UNIT

Overview

- Entered France in 1997 and completed three subsequent acquisitions, including two in 2012.
- Largest oil producer in France.
- Producing assets include large conventional fields with high working interests located in the Aquitaine and Paris Basins with an identified inventory of workover, infill drilling, and secondary recovery opportunities.
- Production is characterized by Brent-based crude pricing and low base decline rates.

Operational review

	Three Months Ended			% change		Nine Months Ended		% change
France business unit	Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	Q3/14 vs. Q2/14	Q3/14 vs. Q3/13	Sep 30, 2014	Sep 30, 2013	2014 vs. 2013
Production								
Crude oil (bbls/d)	**11,111**	11,025	11,625	1%	(4%)	**10,970**	10,786	2%
Natural gas (mmcf/d)	**-**	-	5.23	-	(100%)	**-**	4.54	(100%)
Total (boe/d)	**11,111**	11,025	12,496	1%	(11%)	**10,970**	11,544	(5%)
Inventory (mbbls)								
Opening crude oil inventory	**179**	238	202			**268**	354	
Adjustments	**-**	-	-			**-**	5	
Crude oil production	**1,022**	1,003	1,069			**2,995**	2,945	
Crude oil sales	**(987)**	(1,062)	(1,045)			**(3,049)**	(3,078)	
Closing crude oil inventory	**214**	179	226			**214**	226	
Production mix (% of total)								
Crude oil	**100%**	100%	93%			**100%**	93%	
Natural gas	**-**	-	7%			**-**	7%	
Activity								
Capital expenditures ($M)	**35,082**	37,614	23,664	(7%)	48%	**110,663**	68,479	62%
Gross wells drilled	**3.00**	2.00	-			**7.00**	5.00	
Net wells drilled	**3.00**	2.00	-			**7.00**	5.00	

Production

- Q3 production increased 1% on a quarter-over-quarter basis but remained 11% lower year-over-year. Year-to-date production was 5% lower versus the same period of 2013. Year-over-year and year-to-date production volumes were lower due to the shut-in of gas volumes at Vic Bilh.
- In late September 2013, the third party Lacq processing facility that processed our Vic Bilh gas production was permanently closed. As a result, our Vic Bilh gas production has been temporarily shut-in while preparations to transfer to an alternative facility are completed. We currently expect approximately 850 mcf/d will be back on-stream in early 2015, with the remaining approximately 3,400 mcf/d not anticipated to be back on production until early 2016.
- As a result, current production volumes remain 100% weighted to Brent-based crude.

Activity review

- Vermilion drilled three (3.0 net) wells in the Champotran field in the Paris Basin during Q3 2014.
- During Q3 2014, we also completed a number of workovers, as well as seismic and facility integrity projects.
- The five wells drilled in the Champotran field in 2014 were brought on production at various times during the third quarter and are currently producing approximately 200 bbls/d per well.

Financial review

France business unit ($M except as indicated)	Three Months Ended Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	% change Q3/14 vs. Q2/14	Q3/14 vs. Q3/13	Nine Months Ended Sep 30, 2014	Sep 30, 2013	% change 2014 vs. 2013
Sales	**106,576**	124,617	120,574	(14%)	(12%)	**348,753**	342,558	2%
Royalties	**(6,978)**	(7,796)	(7,574)	(10%)	(8%)	**(22,125)**	(20,468)	8%
Transportation expense	**(4,741)**	(5,385)	(2,713)	(12%)	75%	**(14,879)**	(7,883)	89%
Operating expense	**(15,215)**	(16,550)	(14,599)	(8%)	4%	**(48,185)**	(51,473)	(6%)
General and administration	**(6,411)**	(5,559)	(4,964)	15%	29%	**(17,164)**	(14,577)	18%
Current income taxes	**(10,744)**	(24,761)	(31,717)	(57%)	(66%)	**(60,769)**	(66,500)	(9%)
Fund flows from operations	**62,487**	64,566	59,007	(3%)	6%	**185,631**	181,657	2%
Netbacks ($/boe)								
Sales	**107.99**	117.29	107.08	(8%)	1%	**114.36**	104.29	10%
Royalties	**(7.07)**	(7.34)	(6.73)	(4%)	5%	**(7.26)**	(6.23)	17%
Transportation expense	**(4.80)**	(5.07)	(2.41)	(5%)	99%	**(4.88)**	(2.40)	103%
Operating expense	**(15.42)**	(15.58)	(12.97)	(1%)	19%	**(15.80)**	(15.67)	1%
General and administration	**(6.50)**	(5.24)	(4.41)	24%	47%	**(5.63)**	(4.44)	27%
Current income taxes	**(10.89)**	(23.30)	(28.17)	(53%)	(61%)	**(19.93)**	(20.25)	(2%)
Fund flows from operations netback	**63.31**	60.76	52.39	4%	21%	**60.86**	55.30	10%
Reference prices								
Dated Brent (US $/bbl)	**101.85**	109.63	110.37	(7%)	(8%)	**106.57**	108.45	(2%)

Sales

- Crude oil production in France is priced with reference to Dated Brent.
- Sales per boe for Q3 2014 decreased by 8%, consistent with the 7% decrease in the Dated Brent reference price. This decrease, coupled with a build in inventory during Q3 2014, resulted in a 14% decrease in sales.
- On a year-over-year basis, sales per boe increased by 1% and 10% for the three and nine months ended September 30, 2014 as compared to the same periods in 2013. This sales increase occurred despite an 8% and 2% decrease in Dated Brent reference price for the three and nine months ended September 30, 2014 due to the offsetting impact of the weakening of the Canadian dollar versus the US dollar. On a year-to-date basis, the aforementioned increase in sales per boe was mostly offset by the shut-in of natural gas production, resulting in a 2% increase in sales.

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 revenue).
- As a percentage of sales, royalties for the periods presented remained relatively consistent.

Transportation

- Historically, transportation expense in France related to shipments of crude oil by tanker from the Aquitaine Basin to third party refineries. As a result of the closure of the Lacq processing facility in Q3 2013, Vermilion began incurring additional transportation charges to ship Vic Bilh crude oil production to market. Accordingly, transportation expense per boe for the 2014 periods presented is higher than the expense per boe for the comparative periods from the prior year.

Operating expense

- Operating expense per boe for Q3 2014 was consistent with the prior quarter. The increases in operating expense per boe for the three and nine months ended September 30, 2014 versus the same periods in 2013 are related to a weaker Canadian dollar relative to the Euro in 2014 versus 2013 and the timing of expenditures.

General and administration

- General and administration expense increased in Q3 2014 versus the prior quarter as a result of higher allocations from Vermilion's Corporate segment. These higher allocations, coupled with increased staffing costs and the weaker Canadian dollar relative to the Euro, resulted in an increase in general and administrative expense for the three and nine months ended September 30, 2014.

Current income taxes

- Current income taxes in France apply to taxable income after eligible deductions at a statutory rate of 34.4% for 2014. In addition, a 10.7% temporary surtax is applicable for tax year 2014 and 2015 if annual revenue exceeds 250 million €. For 2014, the effective rate on current taxes is expected to be between approximately 22% and 26% 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 for Q3 2014 were lower than both Q2 2014 and Q3 2013 as Q3 2014 current income taxes reflects our revised expectation of the effective tax rate given the declining Dated Brent reference price. Based on current expectations for Q4 2014 Dated Brent pricing, the France business unit is not expected to be subject to the 10.7% temporary surtax for 2014.
- On a year-to-date basis, current income taxes for the nine months ended September 30, 2014 represents an effective tax rate of 25%. This decrease versus the 27% effective tax rate for the nine months ended September 30, 2013 reflects our revised expectations on the effective tax rate given the declining Dated Brent reference price.

NETHERLANDS BUSINESS UNIT

Overview
- Entered the Netherlands in 2004.
- Second largest onshore gas producer.
- Interests include 16 licenses in the northeast region, five licenses in the central region, and two offshore licenses.
- Licenses include more than 820,000 net acres of undeveloped land.
- High impact natural gas drilling and development.
- Natural gas produced in the Netherlands is priced off the TTF index, which receives a significant premium over North American gas prices.

Operational review

	Three Months Ended			% change		Nine Months Ended		% change
Netherlands business unit	**Sep 30, 2014**	**Jun 30, 2014**	**Sep 30, 2013**	**Q3/14 vs. Q2/14**	**Q3/14 vs. Q3/13**	**Sep 30, 2014**	**Sep 30, 2013**	**2014 vs. 2013**
Production								
NGLs (bbls/d)	**63**	96	48	(34%)	31%	**76**	65	17%
Natural gas (mmcf/d)	**38.07**	40.35	28.78	(6%)	32%	**40.50**	34.71	17%
Total (boe/d)	**6,407**	6,822	4,845	(6%)	32%	**6,827**	5,849	17%
Activity								
Capital expenditures ($M)	**10,087**	21,513	8,316	(53%)	21%	**51,718**	12,845	303%
Gross wells drilled	**1.00**	2.00	-			**5.00**	-	
Net wells drilled	**0.45**	1.43	-			**3.74**	-	

Production
- Production was 6% lower quarter-over-quarter while year-over-year production growth exceeded 32%. Year-to-date production volumes have increased 17% versus the same period of 2013. Both year-over-year and year-to-date production volumes benefited from the addition of production from the DeHoeve-01 well during the second quarter and increased throughput capacity following a retrofit at our Middenmeer Treatment Centre completed in late 2013.
- Production in the Netherlands is managed to meet corporate targets, optimize facility use and regulate declines.

Activity review
- Vermilion drilled the Diever-02 well (45% working interest), in the Drenthe IIIb concession, during Q3 2014. The well primarily targeted the Rotliegend Group (Permian sandstones) where it encountered two well-developed gas bearing intervals (Akkrum and Slochteren) with a net pay thickness of approximately 36 metres.
- A subsequent three hour clean-up test conducted on the Slochteren formation delivered 25.7 mmcf/d of gas on a 40/64 inch choke with 2,615 psi of wellhead flowing pressure with no indications of pressure drop during the test(1). The flow rate was limited by the 3.5 inch diameter of the tubing and the capacity of the test equipment. The Akkrum formation is anticipated to be perforated at a later date once the Slochteren formation has been fully produced.
- The Diever-02 well marked the first well drilled by Vermilion on the lands acquired in October 2013.
- An additional two wells (Langezwaag-02 and Sonnega-02) are planned for drilling during Q4 2014.

(1) Test result is not necessarily indicative of long-term performance or of ultimate recovery.

Financial review

Netherlands business unit ($M except as indicated)	Three Months Ended Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	% change Q3/14 vs. Q2/14	Q3/14 vs. Q3/13	Nine Months Ended Sep 30, 2014	Sep 30, 2013	% change 2014 vs. 2013
Sales	**26,960**	29,881	27,382	(10%)	(2%)	**98,395**	100,119	(2%)
Royalties	**(942)**	(693)	-	36%	100%	**(3,843)**	-	100%
Operating expense	**(5,409)**	(6,390)	(5,209)	(15%)	4%	**(17,841)**	(14,438)	24%
General and administration	**(204)**	(326)	(333)	(37%)	(39%)	**(1,128)**	(1,171)	(4%)
Current income taxes	**(1,189)**	(1,301)	(6,810)	(9%)	(83%)	**(6,278)**	(25,865)	(76%)
Fund flows from operations	**19,216**	21,171	15,030	(9%)	28%	**69,305**	58,645	18%
Netbacks ($/boe)								
Sales	**45.73**	48.14	61.44	(5%)	(26%)	**52.80**	62.70	(16%)
Royalties	**(1.60)**	(1.12)	-	43%	100%	**(2.06)**	-	100%
Operating expense	**(9.18)**	(10.29)	(11.69)	(11%)	(21%)	**(9.57)**	(9.04)	6%
General and administration	**(0.35)**	(0.53)	(0.75)	(34%)	(53%)	**(0.61)**	(0.73)	(16%)
Current income taxes	**(2.02)**	(2.10)	(15.28)	(4%)	(87%)	**(3.37)**	(16.20)	(79%)
Fund flows from operations netback	**32.58**	34.10	33.72	(4%)	(3%)	**37.19**	36.73	1%
Reference prices								
TTF ($/GJ)	**7.26**	7.91	9.94	(8%)	(27%)	**8.41**	10.17	(17%)
TTF (€/GJ)	**5.04**	5.27	7.20	(4%)	(30%)	**5.68**	7.53	(25%)

Sales

- The price of our natural gas in the Netherlands is based on the TTF day-ahead index, as determined on the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services, plus various fees. GasTerra, a state owned entity, continues to purchase all of the natural gas we produce in the Netherlands.
- The decreases in sales per boe in Q3 2014 versus Q2 2014 and Q3 2013 was largely in-line with the change in the Canadian dollar equivalent of the TTF reference price.
- On a year-over-year basis, sales declined by 2% as a result of the 17% decrease in the TTF reference price offset by a 17% increase in production.

Royalties

- Historically, we have not paid royalties in the Netherlands, however, certain wells associated with an acquisition completed by Vermilion's Netherlands business unit in October 2013 have reached payout and are now subject to an overriding royalty.

Transportation expense

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

Operating expense

- Operating expense per boe decreased in Q3 2014 from Q2 2014 due to the timing of project work.
- Operating expense per boe decreased in Q3 2014 as compared to Q3 2013 due to significantly higher volumes year-over-year.
- For the year-to-date period ended Q3 2014, operating expense per boe increased as compared to the prior year due to the strengthening of the Euro versus the Canadian dollar as well as higher salary costs associated with continued organic growth in the Netherlands business unit.

General and administration

- General and administration expense remained relatively consistent for the periods presented, although the quarterly periods are impacted by the timing of expenditures.

Current income taxes

- Current income taxes in the Netherlands apply to taxable income after eligible deductions at a statutory tax rate of approximately 46%. For 2014, the effective rate on current taxes is expected to be between approximately 6% and 8%. 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 decreased for the nine months ended September 30, 2014 as compared to the same period in 2013 as a result of decreased revenues, lower TTF reference prices and an increase in tax deductions for depletion during the current year.

GERMANY BUSINESS UNIT

Overview

- Vermilion entered Germany in February 2014 with the purchase of a 25% participation interest in a four-partner consortium.
- The assets of the four-partner consortium include four gas producing fields across 11 production licenses and an exploration license in surrounding fields.
- Production licenses comprising 207,000 gross acres, of which 85% is in the exploration license.

Operational review

	Three Months Ended		% change	Nine Months Ended
Germany business unit	**Sep 30, 2014**	**Jun 30, 2014**	**Q3/14 vs. Q2/14**	**Sep 30, 2014**
Production				
Natural gas (mmcf/d)	**15.38**	16.13	(5%)	**14.07**
Total (boe/d)	**2,563**	2,689	(5%)	**2,345**
Activity				
Capital expenditures ($M)	**1,358**	630	116%	**2,184**
Acquisitions ($M)	**-**	-		**172,871**

Production

- Achieved Q3 2014 production of 2,563 boe/d, a decrease of 5% as compared to 2,689 boe/d in Q2 2014. Year-to-date production has averaged 2,345 boe/d, taking into account an effective date for production of February 1, 2014.

Activity review

- Continued the integration of the German business unit and commenced planning with our working interest partners for future drilling operations.
- During the first quarter of 2014, we participated in the drilling of the Deblinghausen Z7a development well (25% working interest) in Germany. The well logged 81 metres of net pay in the Zechstein Carbonate, and was production tested by the operator in late September for a period of 17 days. During the test, the Deblinghausen Z7a well produced raw gas at rates of 10.2 mmcf/d at a flowing tubing pressure of 1,840 psi[(1)]. Subsequent to the end of the quarter, this well was placed on production at an initial gross production rate of 16.5 mmcf/d of raw gas at a flowing tubing pressure of approximately 1,300 psi.
- We have hired a Managing Director for the German business unit and have opened an office outside of Berlin, which we are currently outfitting and staffing.

(1) Test result is not necessarily indicative of long-term performance or of ultimate recovery.

Financial review

Germany business unit ($M except as indicated)	Three Months Ended Sep 30, 2014	Three Months Ended Jun 30, 2014	% change Q3/14 vs. Q2/14	Nine Months Ended Sep 30, 2014
Sales	**8,591**	11,097	(23%)	**28,603**
Royalties	**(2,046)**	(2,284)	(10%)	**(6,132)**
Transportation expense	**(675)**	(1,052)	(36%)	**(2,149)**
Operating expense	**(2,227)**	(2,043)	9%	**(5,824)**
General and administration	**(1,090)**	(830)	31%	**(2,488)**
Current income taxes	**(146)**	(506)	(71%)	**(1,189)**
Fund flows from operations	**2,407**	4,382	(45%)	**10,821**
Netbacks ($/boe)				
Sales	**36.43**	45.36	(20%)	**44.68**
Royalties	**(8.68)**	(9.34)	(7%)	**(9.58)**
Transportation expense	**(2.86)**	(4.30)	(33%)	**(3.36)**
Operating expense	**(9.44)**	(8.35)	13%	**(9.10)**
General and administration	**(4.62)**	(3.39)	36%	**(3.89)**
Current income taxes	**(0.62)**	(2.07)	(70%)	**(1.86)**
Fund flows from operations netback	**10.21**	17.91	(43%)	**16.89**
Reference prices				
TTF ($/GJ)	**7.26**	7.91	(8%)	**8.41**
TTF (€/GJ)	**5.04**	5.27	(4%)	**5.68**

Sales

- The price of our natural gas in Germany is based on the TTF month-ahead index, as determined on the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services, plus various fees.
- Sales per boe decreased by 20% from Q2 2014 due to a decrease in the TTF reference price. This decrease, coupled with lower production volumes, resulted in a 23% quarter-over-quarter decrease in sales.

Royalties expense

- Our production in Germany is subject to royalties at a rate of approximately 20% of natural gas sales revenue.

Transportation expense

- Transportation expense relates to costs incurred to deliver natural gas from the processing facility to the customer.

Operating expense

- Operating expenses for Germany are billed monthly by the joint venture operator and are similar on a per boe basis to our Netherlands business unit.

General and administration

- General and administration expense increased quarter-over-quarter as a result of adding staff to the German business unit.

Current income taxes

- Current income taxes in Germany apply to taxable income after eligible deductions at a statutory tax rate of approximately 23%. For 2014, the effective rate on current taxes is expected to be between approximately 4% and 8%. This rate is subject to change in response to commodity price fluctuations, the timing of capital expenditures and other eligible in-country adjustments.

IRELAND BUSINESS UNIT

Overview

- 18.5% non-operating interest in the offshore Corrib gas field located approximately 83km off the northwest coast of Ireland.
- Project comprises six offshore wells, both offshore and onshore pipeline segments as well as a natural gas processing facility.
- Production from Corrib is expected to increase Vermilion's volumes by approximately 58 mmcf/d (9,700 boe/d) once the field reaches peak production.

Operational and financial review

Ireland business unit ($M)	Three Months Ended Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	% change Q3/14 vs. Q2/14	Q3/14 vs. Q3/13	Nine Months Ended Sep 30, 2014	Sep 30, 2013	% change 2014 vs. 2013
Transportation expense	**(1,515)**	(1,571)	(564)	(4%)	169%	**(4,674)**	(3,808)	23%
General and administration	**(334)**	(252)	(312)	33%	7%	**(868)**	(959)	(9%)
Fund flows from operations	**(1,849)**	(1,823)	(876)	1%	111%	**(5,542)**	(4,767)	16%
Activity								
Capital expenditures	**30,050**	27,221	35,028	10%	(14%)	**73,507**	76,426	(4%)

Activity review

- Completed tunnel boring operations beneath Sruwaddacon Bay on May 21, 2014. Installation of flow and umbilical lines has been completed in the 4.9 km tunnel, with remaining work including final cable installation, hydro-testing and grouting. Offshore well and flow line activities are complete and the wells are ready for operation.
- Based on our deterministic schedule for remaining construction and commissioning activities, we anticipate first gas in approximately mid-2015 with peak production of approximately 58 mmcf/d (9,700 boe/d), net to Vermilion.

Transportation expense

- Transportation expense in Ireland relates to payments under a ship or pay agreement related to the Corrib project.

AUSTRALIA BUSINESS UNIT

Overview

- Entered Australia in 2005.
- Hold title to a 100% 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 21 producing well bores.
- Wells are located 600 metres below the sea bed with 500 to 3,000 plus metre horizontal lengths.
- Contracted crude oil production is priced with reference to Dated Brent.

Operational review

	Three Months Ended			% change		Nine Months Ended		% change
Australia business unit	Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	Q3/14 vs. Q2/14	Q3/14 vs. Q3/13	Sep 30, 2014	Sep 30, 2013	2014 vs. 2013
Production								
Crude oil (bbls/d)	**6,567**	6,483	7,070	1%	(7%)	**6,718**	6,580	2%
Inventory (mbbls)								
Opening crude oil inventory	**189**	63	187			**130**	268	
Crude oil production	**604**	590	650			**1,834**	1,796	
Crude oil sales	**(535)**	(464)	(654)			**(1,706)**	(1,881)	
Closing crude oil inventory	**258**	189	183			**258**	183	
Activity								
Capital expenditures ($M)	**15,985**	10,991	5,880	45%	172%	**32,667**	69,511	(53%)
Gross wells drilled	**-**	-	-			**-**	2.00	
Net wells drilled	**-**	-	-			**-**	2.00	

Production

- Quarterly production increased 1% quarter-over-quarter and was 7% lower year-over-year. Year-to-date 2014 production has increased 2% versus the same period 2013.
- Production volumes are managed to meet customer demands and long-term supply agreements. We continue to plan for production levels of between 6,000 and 8,000 bbls/d.
- Production continues to reflect strong well results from the 2013 drilling program, more than offsetting natural declines. We continue to produce the wells at restricted rates below their current productive capacity.

Activity review

- In Q3 2014, efforts were largely focused on facilities repairs and engineering studies, including the expansion of accommodation quarters on the Wandoo B platform.
- 2014 planned activities include ongoing facilities maintenance, enhancement, and refurbishment along with preparation and permitting activities in advance of our planned two-well 2015 drilling program.

Financial review

Australia business unit ($M except as indicated)	Three Months Ended Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	% change Q3/14 vs. Q2/14	Q3/14 vs. Q3/13	Nine Months Ended Sep 30, 2014	Sep 30, 2013	% change 2014 vs. 2013
Sales	**63,708**	58,828	79,229	8%	(20%)	**212,510**	221,412	(4%)
Operating expense	**(14,302)**	(12,051)	(13,668)	19%	5%	**(43,713)**	(38,406)	14%
General and administration	**(1,378)**	(1,661)	(1,414)	(17%)	(3%)	**(4,245)**	(4,310)	(2%)
PRRT	**(13,834)**	(12,699)	(15,649)	9%	(12%)	**(46,772)**	(39,392)	19%
Corporate income taxes	**(5,148)**	(5,689)	(7,666)	(10%)	(33%)	**(19,678)**	(25,525)	(23%)
Fund flows from operations	**29,046**	26,728	40,832	9%	(29%)	**98,102**	113,779	(14%)
Netbacks ($/boe)								
Sales	**119.07**	126.87	120.95	(6%)	(2%)	**124.59**	117.65	6%
Operating expense	**(26.73)**	(25.99)	(20.86)	3%	28%	**(25.63)**	(20.41)	26%
General and administration	**(2.58)**	(3.58)	(2.16)	(28%)	19%	**(2.49)**	(2.29)	9%
PRRT	**(25.86)**	(27.39)	(23.89)	(6%)	8%	**(27.42)**	(20.93)	31%
Corporate income taxes	**(9.62)**	(12.27)	(11.70)	(22%)	(18%)	**(11.54)**	(13.56)	(15%)
Fund flows from operations netback	**54.28**	57.64	62.34	(6%)	(13%)	**57.51**	60.46	(5%)
Reference prices								
Dated Brent (US $/bbl)	**101.85**	109.63	110.37	(7%)	(8%)	**106.57**	108.45	(2%)

Sales

- Our production in Australia currently receives a premium to Dated Brent.
- Sales per boe for Q3 2014 decreased by 6% versus Q2 2014 as a result of a decrease in the Dated Brent reference price. This decrease was offset by larger sales volumes resulting in an 8% increase in sales.
- Sales per boe for the three and nine months ended September 30, 2014 versus the same periods in 2013 reflect the decrease in the Dated Brent reference price offset by the weakening of the Canadian dollar versus the US dollar. These changes, coupled with lower sales volumes, resulted in a 20% and 4% decrease in sales in the three and nine months ended September 30, 2014 versus the same periods in 2013.

Royalties and transportation expense

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

Operating expense

- Operating expense per boe for Q3 2014 remained consistent with the expense for Q2 2014.
- Operating expense per boe for the three and nine months ended September 30, 2014 was higher than the expense for the comparative periods in the prior year due to increased diesel usage and higher salary costs.
- Operating expense for the three and nine months ended September 30, 2014 were 5% and 14% higher, respectively, than the comparable periods in 2013 as a result of increased diesel usage and higher salary costs, partially offset by a build in inventory in the current periods. When crude oil inventory is built up, the related operating expense is deferred and carried as inventory on our balance sheet.

General and administration

- General and administration expense decreased slightly during Q3 2014 as compared to Q2 2014 and Q3 2013 due to timing of expenditures. For the year-to-date period ended September 30, 2014, general and administration expense remained consistent with the expense for the same period of the prior year.

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 2014, the combined corporate income tax and PRRT effective rate is expected to be between approximately 38% and 42%. This rate is subject to change in response to commodity price fluctuations, the timing of capital expenditures and other eligible in-country adjustments.
- Combined corporate income taxes and PRRT movements for the three and nine months ended September 30, 2014 versus the comparable periods was largely consistent with the fluctuations in sales. On a year-over-year basis, PRRT for 2014 increased versus the 2013 periods as a result of the lower capital spending in 2014.

CORPORATE

Overview

- Our Corporate segment includes costs related to our global hedging program, financing expenses, and general and administration expenses, primarily incurred in Canada and not directly related to the operations of our business units.

Financial review

	Three Months Ended			Nine Months Ended	
($M)	Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	Sep 30, 2014	Sep 30, 2013
General and administration	**(2,322)**	(2,574)	(1,526)	**(8,647)**	(4,438)
Current income taxes	**(227)**	(378)	(260)	**(778)**	(839)
Interest expense	**(12,918)**	(12,334)	(10,109)	**(36,712)**	(28,134)
Realized gain (loss) on derivatives	**8,837**	2,419	(4,765)	**13,896**	(5,782)
Realized foreign exchange gain (loss)	**812**	587	(1,227)	**(642)**	(572)
Realized other income	**235**	74	221	**530**	770
Fund flows from operations	**(5,583)**	(12,206)	(17,666)	**(32,353)**	(38,995)

General and administration

- General and administration expense was largely consistent in Q3 2014 as compared to Q2 2014.
- On a year-over-year basis, the increase in general and administration costs for the three and nine months ended September 30, 2014 as compared to the same period in 2013 was a result of the impact of certain outstanding Vermilion Incentive Plan ("VIP") awards to be settled partially in cash.

Current income taxes

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

Interest expense

- Interest expense is incurred on our senior unsecured notes and on borrowings under our revolving credit facility. The increase in 2014 versus the comparable periods is due to increased 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 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) with a goal of securing pricing for up to 50% of net of royalty volumes through a portfolio of forward collars, swaps, and physical fixed price arrangements.
- We believe that our hedging philosophy and approach increases the stability of revenues, cash flows and future dividends while also assisting us in the execution of our capital and development plans.
- The realized gain in 2014 related primarily to amounts received on our TTF and Dated Brent derivatives, partially offset by payments made on our AECO derivatives.
- A listing of derivative positions as at September 30, 2014 is included in "Supplemental Table 2" in this MD&A.

FINANCIAL PERFORMANCE REVIEW

($M except per share)	Three Months Ended Sep 30, 2014	Jun 30, 2014	Mar 31, 2014	Dec 31, 2013	Sep 30, 2013	Jun 30, 2013	Mar 31, 2013	Dec 31, 2012
Petroleum and natural gas sales	**344,688**	387,684	381,183	325,108	327,185	311,966	309,576	241,233
Net earnings	**53,903**	53,993	102,788	101,510	67,796	106,198	52,137	56,914
Net earnings per share								
Basic	**0.50**	0.51	1.00	1.00	0.67	1.05	0.53	0.58
Diluted	**0.50**	0.50	0.99	0.98	0.66	1.04	0.51	0.57

The following table shows a reconciliation of the change in net earnings:

($M)	Q3/14 vs. Q2/14	Q3/14 vs. Q3/13	2014 vs. 2013
Net earnings – Comparative period	53,993	67,796	226,131
Changes in:			
Fund flows from operations	(18,178)	32,253	115,471
Equity based compensation	3,497	(1,941)	(9,770)
Unrealized gain or loss on derivative instruments	9,321	11,499	6,375
Unrealized foreign exchange gain or loss	11,879	(16,099)	(43,351)
Unrealized other income	(701)	(321)	282
Accretion	(114)	150	312
Depletion and depreciation	743	(25,333)	(69,821)
Deferred tax	(6,537)	(14,101)	(14,945)
Net earnings – Current Period	**53,903**	**53,903**	**210,684**

The fluctuations in net earnings from quarter-to-quarter and from year-to-year 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 to non-cash compensation expense attributable to long-term incentives granted to directors, officers and employees under the 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 expense for the three and nine months ended September 30, 2014 was higher than the same periods in 2013 as a result of an upward revision of future performance condition assumptions during Q2 2014. Equity based compensation expense was lower for Q3 2014 as compared to Q2 2014 due to aforementioned upward revision of future performance condition assumptions during Q2 2014.

Unrealized gain or loss on derivative instruments

Unrealized gain or loss on derivative instruments arise as a result of changes in forecasted future commodity prices. As Vermilion uses derivative instruments to manage the commodity price exposure of our future crude oil and natural gas production, we will normally recognize unrealized gains on derivative instruments when forecasted future commodity prices decline and vice-versa.

In the nine months ended September 30, 2014, we recognized an unrealized gain on derivative instruments of $10.1 million, relating primarily to our crude oil swaps and collars. As at September 30, 2014, we have a net derivative asset position of $7.6 million.

Unrealized foreign exchange gain or loss

As a result of Vermilion's international operations, Vermilion conducts business in currencies other than the Canadian dollar and has monetary assets and liabilities (including cash, receivables, payables, derivative assets and liabilities, and intercompany loans) denominated in such currencies. Vermilion's exposure to foreign currencies includes the US dollar, the Euro and the Australian Dollar.

Unrealized foreign exchange gains and losses are the result of translating monetary assets and liabilities held in non-functional currencies to the respective functional currencies of Vermilion and its subsidiaries. Unrealized foreign exchange primarily results from the translation of Euro denominated financial assets. As such, an appreciation in the Euro against the Canadian dollar will result in an unrealized foreign exchange gain, and vice-versa.

For the three and nine months ended September 30, 2014, the Canadian dollar strengthened versus the Euro resulting in unrealized foreign exchange losses of $11.9 million and $13.6 million, respectively.

Accretion
Fluctuations in accretion expense is primarily the result of changes in discount rates applicable to the balance of asset retirement obligations and additions resulting from drilling and acquisitions.

Q3 2014 accretion expense was relatively consistent as compared to Q2 2014 and the comparable periods in 2013.

Depletion and depreciation
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 2014 of $23.21 was higher as compared to Q2 2014 of $22.45/boe as a result of lower production in Canada. Depletion and depreciation on a per boe basis increased for the three and nine month periods ended September 30, 2014 to $23.21/boe and $22.92/boe, respectively, as compared to the same periods in 2013 of $20.74/boe and $20.91/boe, respectively. The increase on a per boe basis was largely due to Vermilion's increased capital and acquisition activity which results in higher per boe amounts when compared to legacy producing assets.

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

FINANCIAL POSITION REVIEW

Balance sheet strategy
We believe that our balance sheet supports our defined growth initiatives and our focus is on managing and maintaining a conservative balance sheet. To ensure that our balance sheet continues to support our defined growth initiatives, we regularly review whether forecasted fund flows from operations is sufficient to finance planned capital expenditures, dividends, and abandonment and reclamation expenditures. To the extent that forecasted fund flows from operations is not expected to be sufficient to fulfill such expenditures, we will evaluate our ability to finance any excess with debt (including borrowing using the unutilized capacity of our existing revolving credit facility) or issue equity.

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 1.3. In a 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.

Absent additional material acquisitions, Vermilion currently expects the net debt to fund flows ratio to return to our internally targeted ratio over the next 12 to 24 months as a result of incremental cash flows from Corrib and our acquisitions in Germany and Canada.

Long-term debt
Our long-term debt consists of our revolving credit facility and our senior unsecured notes. The applicable annual interest rates and the balances recognized on our balance sheet are as follows:

	Annual Interest Rate		As At	
($M)	**Sep 30, 2014**	**Dec 31, 2013**	**Sep 30, 2014**	**Dec 31, 2013**
Revolving credit facility	**3.3%**	3.3%	**974,857**	766,898
Senior unsecured notes	**6.5%**	6.5%	**223,791**	223,126
Long-term debt	**3.9%**	4.7%	**1,198,648**	990,024

Revolving Credit Facility
Our revolving credit facility bears interest at rates applicable to demand loans plus applicable margins. The following table outlines the terms of our revolving credit facility:

	As At	
	Sep 30, 2014	Dec 31, 2013
Total facility amount [1]	$1.50 billion	$1.20 billion
Amount drawn	$974.9 million	$766.9 million
Letters of credit outstanding	$10.3 million	$8.1 million
Facility maturity date	31-May-17	31-May-16

(1) We may, by adding lenders or seeking an increase to an existing lender's commitment, increase the total committed facility amount to no more than $1.75 billion.

In addition, the revolving credit facility is subject to the following covenants:

		As At	
Financial covenant	**Limit**	**Sep 30, 2014**	**Dec 31, 2013**
Consolidated total debt to consolidated EBITDA	4.0	1.16	1.06
Consolidated total senior debt to consolidated EBITDA	3.0	0.94	0.82
Consolidated total senior debt to total capitalization	50%	31%	28%

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

- Consolidated total debt: Includes all amounts classified as "Long-term debt" 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 "Long-term debt" and "Shareholders' equity".

Vermilion was in compliance with its financial covenants for all periods presented.

Senior Unsecured Notes
We have outstanding senior unsecured notes that are senior unsecured obligations and rank pari passu with all our other present and future unsecured and unsubordinated indebtedness. The following table outlines the terms of these notes:

Total issued and outstanding amount	$225.0 million
Interest rate	6.5% per annum
Issued date	February 10, 2011
Maturity date	February 10, 2016

Prior to February 10, 2015, Vermilion may redeem all or part of the senior unsecured notes at 103.25% of their principal amount plus any accrued and unpaid interest. Subsequent to February 10, 2015, Vermilion may redeem all or part of the senior unsecured notes at 100% of their principal amount plus any accrued and unpaid interest. The notes were initially recognized at fair value net of transaction costs and are subsequently measured at amortized cost using an effective interest rate of 7.1%.

Net debt
Net debt is reconciled to its most directly comparable GAAP measure, long-term debt, as follows:

	As At	
($M)	**Sep 30, 2014**	**Dec 31, 2013**
Long-term debt	**1,198,648**	990,024
Current liabilities	**431,175**	347,444
Current assets	**(386,385)**	(587,783)
Net debt	**1,243,438**	749,685
Ratio of net debt to annualized fund flows from operations	**1.5**	1.1

Long-term debt as at September 30, 2014 increased to $1.2 billion from $990.0 million as at December 31, 2013 as a result of draws on the revolving credit facility during the current year to fund our acquisitions in Germany and Saskatchewan coupled with the assumption of $47.5 million of long-term debt pursuant to the latter acquisition. This increase in long-term debt resulted in an increase to net debt from $749.7 million to $1.2 billion. As a result of this increase to long-term debt, the year-to-date ratio of net debt to annualized fund flows from operations increased from 1.1 as at December 31, 2013 to 1.5 as at September 30, 2014.

Shareholders' capital

Beginning with the January 2014 dividend paid on February 18, 2014, we increased our monthly dividend by 7.5%. This was our second consecutive annual increase.

During the nine months ended September 30, 2014, we maintained monthly dividends at $0.215 per share and declared dividends totalled $203.6 million.

The following table outlines our dividend payment history:

Date	Monthly dividend per unit or share
January 2003 to December 2007	$0.17
January 2008 to December 2012	$0.19
January 2013 to December 31, 2013	$0.20
Beginning January 2014	$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 price commodity 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.

Over the next two years, we anticipate that Corrib, Cardium and other exploration and development activities will require significant capital investment. Although we currently expect to be able to maintain our current dividend, fund flows from operations may not be sufficient during this period to fund cash dividends, capital expenditures and asset retirement obligations. We will evaluate our ability to finance any shortfalls with debt, issuances of equity or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount ($M)
Balance as at December 31, 2013	102,123	1,618,443
Shares issued pursuant to corporate acquisition	2,827	204,960
Issuance of shares pursuant to the dividend reinvestment plan	902	58,450
Vesting of equity based awards	950	47,657
Share-settled dividends on vested equity based awards	108	7,519
Shares issued pursuant to the bonus plan	11	721
Balance as at September 30, 2014	106,921	1,937,750

As at September 30, 2014, there were approximately 1.7 million VIP awards outstanding. As at November 6, 2014, there were approximately 107.0 million shares outstanding.

ASSET RETIREMENT OBLIGATIONS

As at September 30, 2014, asset retirement obligations were $397.9 million compared to $326.2 million as at December 31, 2013.

The increase in asset retirement obligations is largely attributable to an overall decrease in the discount rates applied to the abandonment obligations, accretion, and additions from new wells drilled during the year and abandonment obligations associated with the assets acquired in Germany and Canada.

OFF BALANCE SHEET ARRANGEMENTS

We have certain lease agreements that are entered into in the normal course of operations, all of which are operating leases and accordingly no asset or liability value has been assigned to the consolidated balance sheet as at September 30, 2014.

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

Accounting pronouncements not yet adopted

The impact of the adoption of the following pronouncements are currently being evaluated.

IFRS 9 "Financial Instruments"
On July 24, 2014, the IASB issued the final element of its comprehensive response to the financial crisis by issuing IFRS 9 "Financial Instruments". The improvements introduced by IFRS 9 includes a logical model for classification and measurement, a single, forward-looking 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. Vermilion will adopt the standard for reporting periods beginning January 1, 2018.

IFRS 15 "Revenue from Contracts with Customers"
On May 28, 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", a new standard that specifies recognition requirements for revenue as well as requiring entities to provide the users of financial statements with more informative and relevant disclosures. The standard replaces IAS 11 "Construction Contracts" and IAS 18 "Revenue" as well as a number of revenue-related interpretations. Vermilion will adopt the standard for reporting periods beginning January 1, 2017.

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, 2013.

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.

The following outlines what management believes to be the most critical accounting policies involving the use of estimates and assumptions:

i. Depletion and depreciation charges are based on estimates of total proven and probable reserves that Vermilion expects to recover in the future.
ii. Asset retirement obligations are based on past experience and current economic factors which management believes are reasonable.
iii. Impairment tests are performed at the cash generating unit (CGU) level, which is determined based on management's judgment. The calculation of the recoverable amount of a CGU is based on market factors as well as estimates of PNG reserves and future costs required to develop reserves.
iv. Deferred tax amounts recognized in the consolidated financial statements are based on management's assessment of the tax positions at the end of each reporting period.

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, 2014			Nine Months Ended September 30, 2014			Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
	Oil & NGLs	Natural Gas	Total	Oil & NGLs	Natural Gas	Total	Total	Total
	$/bbl	$/mcf	$/boe	$/bbl	$/mcf	$/boe	$/boe	$/boe
Canada								
Sales	91.25	4.44	**64.85**	95.24	4.82	**68.58**	63.56	61.16
Royalties	(13.37)	(0.40)	**(8.89)**	(12.06)	(0.35)	**(8.05)**	(7.09)	(6.41)
Transportation	(2.50)	(0.17)	**(1.89)**	(2.33)	(0.17)	**(1.80)**	(2.08)	(1.75)
Operating	(9.19)	(1.42)	**(8.91)**	(9.73)	(1.39)	**(9.17)**	(8.12)	(9.15)
Operating netback	66.19	2.45	**45.16**	71.12	2.91	**49.56**	46.27	43.85
General and administration			**(2.11)**			**(2.25)**	(2.21)	(2.26)
Fund flows from operations netback			**43.05**			**47.31**	44.06	41.59
France								
Sales	107.99	-	**107.99**	114.36	-	**114.36**	107.08	104.29
Royalties	(7.07)	-	**(7.07)**	(7.25)	-	**(7.26)**	(6.73)	(6.23)
Transportation	(4.80)	-	**(4.80)**	(4.88)	-	**(4.88)**	(2.41)	(2.40)
Operating	(15.42)	-	**(15.42)**	(15.80)	-	**(15.80)**	(12.97)	(15.67)
Operating netback	80.70	-	**80.70**	86.43	-	**86.42**	84.97	79.99
General and administration			**(6.50)**			**(5.63)**	(4.41)	(4.44)
Current income taxes			**(10.89)**			**(19.93)**	(28.17)	(20.25)
Fund flows from operations netback			**63.31**			**60.86**	52.39	55.30
Netherlands								
Sales	90.01	7.55	**45.73**	96.66	8.72	**52.80**	61.44	62.70
Royalties	-	(0.27)	**(1.60)**	-	(0.35)	**(2.06)**	-	-
Operating	-	(1.54)	**(9.18)**	-	(1.61)	**(9.57)**	(11.69)	(9.04)
Operating netback	90.01	5.74	**34.95**	96.66	6.76	**41.17**	49.75	53.66
General and administration			**(0.35)**			**(0.61)**	(0.75)	(0.73)
Current income taxes			**(2.02)**			**(3.37)**	(15.28)	(16.20)
Fund flows from operations netback			**32.58**			**37.19**	33.72	36.73
Germany								
Sales	-	6.07	**36.43**	-	7.45	**44.68**	-	-
Royalties	-	(1.45)	**(8.68)**	-	(1.60)	**(9.58)**	-	-
Transportation	-	(0.48)	**(2.86)**	-	(0.56)	**(3.36)**	-	-
Operating	-	(1.57)	**(9.44)**	-	(1.52)	**(9.10)**	-	-
Operating netback	-	2.57	**15.45**	-	3.77	**22.64**	-	-
General and administration			**(4.62)**			**(3.89)**	-	-
Current income taxes			**(0.62)**			**(1.86)**	-	-
Fund flows from operations netback			**10.21**			**16.89**	-	-
Australia								
Sales	119.07	-	**119.07**	124.59	-	**124.59**	120.95	117.65
Operating	(26.73)	-	**(26.73)**	(25.63)	-	**(25.63)**	(20.86)	(20.41)
PRRT [1]	(25.86)	-	**(25.86)**	(27.42)	-	**(27.42)**	(23.89)	(20.93)
Operating netback	66.48	-	**66.48**	71.54	-	**71.54**	76.20	76.31
General and administration			**(2.58)**			**(2.49)**	(2.16)	(2.29)
Corporate income taxes			**(9.62)**			**(11.54)**	(11.70)	(13.56)
Fund flows from operations netback			**54.28**			**57.51**	62.34	60.46
Total Company								
Sales	102.49	5.74	**76.80**	108.02	6.60	**82.73**	86.10	83.10
Realized hedging gain (loss)	1.57	0.44	**1.97**	0.37	0.36	**1.03**	(1.25)	(0.51)
Royalties	(8.56)	(0.50)	**(6.46)**	(7.88)	(0.51)	**(6.09)**	(4.93)	(4.41)
Transportation	(2.83)	(0.30)	**(2.45)**	(2.77)	(0.31)	**(2.44)**	(1.72)	(1.74)
Operating	(14.73)	(1.48)	**(12.53)**	(15.08)	(1.49)	**(12.81)**	(12.17)	(12.87)
PRRT [1]	(4.95)	-	**(3.08)**	(5.51)	-	**(3.47)**	(4.12)	(3.45)
Operating netback	72.99	3.90	**54.25**	77.15	4.65	**58.95**	61.91	60.12
General and administration			**(3.62)**			**(3.60)**	(3.17)	(3.15)
Interest expense			**(2.88)**			**(2.73)**	(2.66)	(2.46)
Realized foreign exchange gain (loss)			**0.17**			**(0.05)**	(0.32)	(0.05)
Other income			**0.05**			**0.04**	0.06	0.07
Corporate income taxes [1]			**(3.89)**			**(6.59)**	(12.22)	(10.40)
Fund flows from operations netback			**44.08**			**46.02**	43.60	44.13

(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 following tables outline Vermilion's outstanding risk management positions as at September 30, 2014:

	Note	Volume	Strike Price(s)
Crude Oil			
WTI - Collar			
October 2014 - December 2014		250 bbl/d	90.00 - 101.10 US $
WTI - Swap			
May 2014 - November 2014	1	250 bbl/d	97.25 CAD $
July 2014 - December 2014		750 bbl/d	99.00 US $
September 2014 - October 2014	2	500 bbl/d	96.05 US $
October 2014 - November 2014	3	500 bbl/d	92.90 US $
October 2014 - December 2014	4	1,750 bbl/d	94.89 US $
MSW - Fixed Price Differential			
October 2014 - December 2014		1,000 bbl/d	WTI less 8.40 US $
Dated Brent - Collar			
April 2014 - December 2014		1,000 bbl/d	106.00 - 110.73 US $
October 2014 - December 2014		800 bbl/d	95.00 - 121.60 US $
Dated Brent - Swap			
January 2014 - December 2014		500 bbl/d	108.28 US $
July 2014 - December 2014		1,000 bbl/d	109.64 US $
July 2014 - December 2014	5	500 bbl/d	109.40 US $
September 2014 - December 2014	5	500 bbl/d	108.08 US $
October 2014 - December 2014	4	700 bbl/d	104.48 US $
January 2015	6	250 bbl/d	107.45 US $
February 2015	7	250 bbl/d	109.00 US $
March 2015	8	250 bbl/d	110.40 US $
MSW - Fixed Price Differential (Physical)			
April 2014 - December 2014		1,030 bbl/d	WTI less 8.20 US $
July 2014 - December 2014		2,052 bbl/d	WTI less 8.68 US $
November 2014 - March 2015		1,042 bbl/d	WTI less 6.85 US $
January 2015 - March 2015		1,573 bbl/d	WTI less 7.43 US $
LSB - Fixed Price Differential (Physical)			
October 2014 - December 2014		513 bbl/d	WTI less 9.00 US $
October 2014 - March 2015		830 bbl/d	WTI less 10.00 US $
January 2015 - March 2015		524 bbl/d	WTI less 8.60 US $

(1) Assumed as part of Vermilion's April 29, 2014 acquisition of Elkhorn Resources Inc.
(2) Prior to the expiration of this swap, the counterparty has the option to extend the swap to December 31, 2014 at the contracted volume and price.
(3) Prior to the expiration of this swap, the counterparty has the option to extend the swap to January 31, 2015 at the contracted volume and price.
(4) Prior to the expiration of this swap, the counterparty has the option to extend the swap to March 31, 2015 at the contracted volume and price.
(5) Prior to the expiration of this swap, the counterparty has the option to extend the swap to June 30, 2015 at the contracted volume and price.
(6) On March 31, 2015, the counterparty has the option to extend the swap for the period of April to June 2015 for 500 boe/d at the contracted price.
(7) On June 30, 2015, the counterparty has the option to extend the swap for the period of July to September 2015 for 500 boe/d at the contracted price.
(8) On September 30, 2015, the counterparty has the option to extend the swap for the period of October to December 2015 for 500 boe/d at the contracted price.

	Note	Volume	Strike Price(s)
Canadian Natural Gas			
AECO - Collar			
January 2014 - December 2014		10,000 GJ/d	3.18 - 3.81 CAD $
April 2014 - December 2014		1,000 GJ/d	3.60 - 3.96 CAD $
April 2014 - March 2015		2,500 GJ/d	3.60 - 4.08 CAD $
November 2014 - March 2015		2,500 GJ/d	3.60 - 4.27 CAD $
AECO - Swap			
January 2014 - December 2014		5,000 GJ/d	3.71 CAD $
April 2014 - October 2014		8,000 GJ/d	4.00 CAD $
European Natural Gas			
TTF - Collar			
October 2014 - December 2014		1,800 GJ/d	6.11 - 7.08 EUR €
TTF - Swap			
October 2014 - December 2014		3,600 GJ/d	6.71 EUR €
Electricity			
AESO - Swap			
January 2014 - December 2014		7.2 MWh/d	54.75 CAD $
AESO - Swap (Physical)			
January 2013 - December 2015		72.0 MWh/d	53.17 CAD $
US Dollar			
USD - Collar			
October 2014 - December 2014		1,500,000 USD $/month	1.075 - 1.145 CAD $
October 2014 - December 2014	1	7,500,000 USD $/month	1.092 - 1.114 CAD $

(1) Vermilion has upside participation on this hedge up to the limit price of 1.176 CAD; above which, settlement will occur at the conditional call level of 1.114 CAD.

Supplemental Table 3: Capital Expenditures

By classification ($M)	Three Months Ended Sep 30, 2014	Three Months Ended Jun 30, 2014	Three Months Ended Sep 30, 2013	Nine Months Ended Sep 30, 2014	Nine Months Ended Sep 30, 2013
Drilling and development	**180,479**	117,975	135,110	**467,294**	389,635
Dispositions	**-**	-	-	**-**	(8,627)
Exploration and evaluation	**9,554**	17,098	551	**54,187**	13,240
Capital expenditures	**190,033**	135,073	135,661	**521,481**	394,248
Property acquisition	**40,847**	-	7,586	**219,074**	7,586
Corporate acquisition	**-**	381,139	-	**381,139**	-
Acquisitions	**40,847**	381,139	7,586	**600,213**	7,586

By category ($M)	Three Months Ended Sep 30, 2014	Three Months Ended Jun 30, 2014	Three Months Ended Sep 30, 2013	Nine Months Ended Sep 30, 2014	Nine Months Ended Sep 30, 2013
Land	**2,346**	950	(4,450)	**8,049**	986
Seismic	**6,135**	1,869	5,284	**11,436**	14,666
Drilling and completion	**93,386**	42,083	63,590	**242,005**	210,010
Production equipment and facilities	**68,964**	60,547	47,665	**198,266**	138,426
Recompletions	**10,853**	13,459	15,650	**28,538**	24,291
Other	**8,349**	16,165	7,922	**33,187**	14,496
Dispositions	**-**	-	-	**-**	(8,627)
Capital expenditures	**190,033**	135,073	135,661	**521,481**	394,248
Acquisitions	**40,847**	381,139	7,586	**600,213**	7,586
Total capital expenditures and acquisitions	**230,880**	516,212	143,247	**1,121,694**	401,834

By country ($M)	Three Months Ended Sep 30, 2014	Three Months Ended Jun 30, 2014	Three Months Ended Sep 30, 2013	Nine Months Ended Sep 30, 2014	Nine Months Ended Sep 30, 2013
Canada	**125,276**	418,294	69,856	**663,277**	171,538
France	**35,082**	37,614	23,664	**110,663**	68,479
Netherlands	**10,087**	21,513	8,316	**51,718**	12,845
Germany	**1,358**	630	-	**175,055**	-
Ireland	**30,050**	27,221	35,028	**73,507**	76,426
Australia	**15,985**	10,991	5,880	**32,667**	69,511
Corporate	**13,042**	(51)	503	**14,807**	3,035
Total capital expenditures and acquisitions	**230,880**	516,212	143,247	**1,121,694**	401,834

Supplemental Table 4: Production

	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13	Q2/13	Q1/13	Q4/12	Q3/12	Q2/12	Q1/12	Q4/11
Canada												
Crude oil (bbls/d)	**11,469**	12,676	9,437	8,719	7,969	8,885	7,966	7,983	7,322	7,757	7,574	6,591
NGLs (bbls/d)	**2,291**	2,796	2,071	1,699	1,897	1,725	1,335	1,106	1,204	1,321	1,302	1,246
Natural gas (mmcf/d)	**57.07**	57.59	49.53	41.43	43.40	43.69	41.04	31.41	35.54	41.32	41.83	43.96
Total (boe/d)	**23,272**	25,070	19,763	17,322	17,099	17,892	16,140	14,323	14,449	15,965	15,848	15,163
% of consolidated	**47%**	49%	42%	43%	41%	42%	41%	40%	40%	40%	40%	41%
France												
Crude oil (bbls/d)	**11,111**	11,025	10,771	11,131	11,625	10,390	10,330	9,843	9,767	9,931	10,270	7,819
Natural gas (mmcf/d)	**-**	-	-	-	5.23	4.19	4.21	3.91	3.39	3.57	3.48	0.94
Total (boe/d)	**11,111**	11,025	10,771	11,131	12,496	11,088	11,032	10,495	10,333	10,526	10,850	7,976
% of consolidated	**22%**	21%	23%	27%	30%	26%	29%	29%	28%	27%	28%	22%
Netherlands												
NGLs (bbls/d)	**63**	96	69	62	48	50	96	70	41	84	72	66
Natural gas (mmcf/d)	**38.07**	40.35	43.15	37.53	28.78	38.52	36.91	33.03	34.59	33.74	35.08	34.58
Total (boe/d)	**6,407**	6,822	7,260	6,318	4,845	6,470	6,248	5,574	5,806	5,707	5,919	5,829
% of consolidated	**13%**	13%	16%	15%	12%	15%	16%	15%	16%	15%	15%	16%
Germany												
Natural gas (mmcf/d)	**15.38**	16.13	10.64	-	-	-	-	-	-	-	-	-
Total (boe/d)	**2,563**	2,689	1,773	-	-	-	-	-	-	-	-	-
% of consolidated	**5%**	5%	4%	-	-	-	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	**6,567**	6,483	7,110	6,189	7,070	7,363	5,287	5,873	5,958	6,970	6,648	7,686
% of consolidated	**13%**	12%	15%	15%	17%	17%	14%	16%	16%	18%	17%	21%
Consolidated												
Crude oil & NGLs (bbls/d)	**31,501**	33,076	29,458	27,800	28,609	28,413	25,014	24,875	24,292	26,063	25,866	23,408
% of consolidated	**63%**	63%	63%	68%	69%	66%	65%	69%	66%	67%	66%	64%
Natural gas (mmcf/d)	**110.52**	114.08	103.32	78.96	77.41	86.40	82.16	68.34	73.52	78.63	80.39	79.48
% of consolidated	**37%**	37%	37%	32%	31%	34%	35%	31%	34%	33%	34%	36%
Total (boe/d)	**49,920**	52,089	46,677	40,960	41,510	42,813	38,707	36,265	36,546	39,168	39,265	36,654

	YTD 2014	2013	2012	2011	2010	2009
Canada						
Crude oil (bbls/d)	**11,202**	8,387	7,659	4,701	2,778	2,137
NGLs (bbls/d)	**2,387**	1,666	1,232	1,297	1,427	1,518
Natural gas (mmcf/d)	**54.76**	42.39	37.50	43.38	43.91	47.85
Total (boe/d)	**22,714**	17,117	15,142	13,227	11,524	11,629
% of consolidated	**45%**	41%	40%	38%	36%	37%
France						
Crude oil (bbls/d)	**10,970**	10,873	9,952	8,110	8,347	8,246
Natural gas (mmcf/d)	**-**	3.40	3.59	0.95	0.92	1.05
Total (boe/d)	**10,970**	11,440	10,550	8,269	8,501	8,421
% of consolidated	**22%**	28%	28%	23%	26%	27%
Netherlands						
NGLs (bbls/d)	**76**	64	67	58	35	23
Natural gas (mmcf/d)	**40.50**	35.42	34.11	32.88	28.31	21.06
Total (boe/d)	**6,827**	5,967	5,751	5,538	4,753	3,533
% of consolidated	**14%**	15%	15%	16%	15%	11%
Germany						
Natural gas (mmcf/d)	**14.07**	-	-	-	-	-
Total (boe/d)	**2,345**	-	-	-	-	-
% of consolidated	**5%**	-	-	-	-	-
Australia						
Crude oil (bbls/d)	**6,718**	6,481	6,360	8,168	7,354	7,812
% of consolidated	**14%**	16%	17%	23%	23%	25%
Consolidated						
Crude oil & NGLs (bbls/d)	**31,353**	27,471	25,270	22,334	19,941	19,735
% of consolidated	**63%**	67%	67%	63%	62%	63%
Natural gas (mmcf/d)	**109.33**	81.21	75.20	77.21	73.14	69.96
% of consolidated	**37%**	33%	33%	37%	38%	37%
Total (boe/d)	**49,574**	41,005	37,803	35,202	32,132	31,395

Supplemental Table 5: Segmented Financial Results

	Three Months Ended September 30, 2014							
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**Corporate**	**Total**
Drilling and development	88,116	34,883	10,087	1,358	30,050	15,985	-	180,479
Exploration and evaluation	9,277	199	-	-	-	-	78	9,554
Oil and gas sales to external customers	138,853	106,576	26,960	8,591	-	63,708	-	344,688
Royalties	(19,034)	(6,978)	(942)	(2,046)	-	-	-	(29,000)
Revenue from external customers	119,819	99,598	26,018	6,545	-	63,708	-	315,688
Transportation expense	(4,048)	(4,741)	-	(675)	(1,515)	-	-	(10,979)
Operating expense	(19,074)	(15,215)	(5,409)	(2,227)	-	(14,302)	-	(56,227)
General and administration	(4,523)	(6,411)	(204)	(1,090)	(334)	(1,378)	(2,322)	(16,262)
PRRT	-	-	-	-	-	(13,834)	-	(13,834)
Corporate income taxes	-	(10,744)	(1,189)	(146)	-	(5,148)	(227)	(17,454)
Interest expense	-	-	-	-	-	-	(12,918)	(12,918)
Realized gain on derivative instruments	-	-	-	-	-	-	8,837	8,837
Realized foreign exchange gain	-	-	-	-	-	-	812	812
Realized other income	-	-	-	-	-	-	235	235
Fund flows from operations	92,174	62,487	19,216	2,407	(1,849)	29,046	(5,583)	197,898

	Nine Months Ended September 30, 2014							
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**Corporate**	**Total**
Total assets	1,857,012	894,060	237,070	164,025	809,296	269,959	206,305	4,437,727
Drilling and development	215,860	99,564	43,512	2,184	73,507	32,667	-	467,294
Exploration and evaluation	33,440	11,099	8,206	-	-	-	1,442	54,187
Oil and gas sales to external customers	425,294	348,753	98,395	28,603	-	212,510	-	1,113,555
Royalties	(49,937)	(22,125)	(3,843)	(6,132)	-	-	-	(82,037)
Revenue from external customers	375,357	326,628	94,552	22,471	-	212,510	-	1,031,518
Transportation expense	(11,170)	(14,879)	-	(2,149)	(4,674)	-	-	(32,872)
Operating expense	(56,863)	(48,185)	(17,841)	(5,824)	-	(43,713)	-	(172,426)
General and administration	(13,951)	(17,164)	(1,128)	(2,488)	(868)	(4,245)	(8,647)	(48,491)
PRRT	-	-	-	-	-	(46,772)	-	(46,772)
Corporate income taxes	-	(60,769)	(6,278)	(1,189)	-	(19,678)	(778)	(88,692)
Interest expense	-	-	-	-	-	-	(36,712)	(36,712)
Realized gain on derivative instruments	-	-	-	-	-	-	13,896	13,896
Realized foreign exchange loss	-	-	-	-	-	-	(642)	(642)
Realized other income	-	-	-	-	-	-	530	530
Fund flows from operations	293,373	185,631	69,305	10,821	(5,542)	98,102	(32,353)	619,337

ADDITIONAL AND NON-GAAP FINANCIAL MEASURES

This MD&A includes references to certain financial measures which do not have standardized meanings prescribed by IFRS. As such, these financial measures are considered additional GAAP or non-GAAP financial measures and therefore may not be comparable with similar measures presented by other issuers.

Fund flows from operations: We define fund flows from operations as cash flows from operating activities before changes in non-cash operating working capital and asset retirement obligations settled. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, fund flows from operations provides a measure of our ability to generate cash (that is not subject to short-term movements in non-cash operating working capital) necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments. As we have presented fund flows from operations in the "Segmented Information" note of our unaudited condensed consolidated interim financial statements for the three and nine months ended September 30, 2014, we consider fund flows from operations to be an additional GAAP financial measure.

Free cash flow: Represents fund flows from operations in excess of capital expenditures. We consider free cash flow to be a key measure as it is used to determine the funding available for investing and financing activities, including payment of dividends, repayment of long-term debt, reallocation to existing business units, and deployment into new ventures.

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

Payout: We define payout as net dividends plus drilling and development, exploration and evaluation, dispositions and asset retirement obligations settled. Management uses payout to assess the amount of cash distributed back to shareholders and re-invested in the business for maintaining production and organic growth.

Fund flows from operations (excluding Corrib) and Payout (excluding Corrib): Management excludes expenditures relating to the Corrib project in assessing fund flows from operations (an additional GAAP financial measure) and payout in order to assess our ability to generate cash and finance organic growth from our current producing assets.

Net debt: We define net debt as the sum of long-term debt and working capital. Management uses net debt, and the **ratio of net debt to fund flows from operations**, to analyze our financial position and leverage. Please refer to the preceding "Net Debt" section for a reconciliation of the net debt non-GAAP financial measure.

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.

Netbacks: Per boe and per mcf measures used in the analysis of operational activities.

Total returns: Includes cash dividends per share and the change in Vermilion's share price on the Toronto Stock Exchange.

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

	Three Months Ended			Nine Months Ended	
($M)	Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	Sep 30, 2014	Sep 30, 2013
Cash flows from operating activities	**235,010**	149,592	158,236	**562,840**	528,022
Changes in non-cash operating working capital	**(41,789)**	64,103	4,671	**46,788**	(30,652)
Asset retirement obligations settled	**4,677**	2,381	2,738	**9,709**	6,496
Fund flows from operations	**197,898**	216,076	165,645	**619,337**	503,866
Expenses related to Corrib	**1,849**	1,823	876	**5,542**	4,767
Fund flows from operations (excluding Corrib)	**199,747**	217,899	166,521	**624,879**	508,633

($M)	Three Months Ended Sep 30, 2014	Jun 30, 2014	Sep 30, 2013	Nine Months Ended Sep 30, 2014	Sep 30, 2013
Dividends declared	**68,896**	68,710	61,003	**203,613**	181,391
Issuance of shares pursuant to the dividend reinvestment plan	**(20,416)**	(19,149)	(19,354)	**(58,450)**	(53,516)
Net dividends	**48,480**	49,561	41,649	**145,163**	127,875
Drilling and development	**180,479**	117,975	135,110	**467,294**	389,635
Dispositions	**-**	-	-	**-**	(8,627)
Exploration and evaluation	**9,554**	17,098	551	**54,187**	13,240
Asset retirement obligations settled	**4,677**	2,381	2,738	**9,709**	6,496
Payout	**243,190**	187,015	180,048	**676,353**	528,619
Corrib drilling and development	**(30,050)**	(27,221)	(35,028)	**(73,507)**	(76,426)
Payout (excluding Corrib)	**213,140**	159,794	145,020	**602,846**	452,193

('000s of shares)	As At Sep 30, 2014	Jun 30, 2014	Sep 30, 2013
Shares outstanding	**106,921**	106,620	101,787
Potential shares issuable pursuant to the VIP	**2,828**	2,751	2,408
Diluted shares outstanding	**109,749**	109,371	104,195

CORPORATE INFORMATION

DIRECTORS

Larry J. Macdonald [1, 2, 3, 4, 5]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

W. Kenneth Davidson [2, 3]
Toronto, Ontario

Lorenzo Donadeo
Calgary, Alberta

Claudio A. Ghersinich [2, 5]
Executive Director, Carrera Investments Corp.
Calgary, Alberta

Joseph F. Killi [2, 3]
Chairman, Parkbridge Lifestyle Communities Inc.
Vice Chairman, Realex Properties Corp.
Calgary, Alberta

Loren M. Leiker [5]
Houston, Texas

William F. Madison [2, 4, 5]
Sugar Land, Texas

Timothy R. Marchant [3, 4, 5]
Calgary, Alberta

Sarah E. Raiss [3]
Calgary, Alberta

[1] Chairman of the Board
[2] Audit Committee
[3] Governance and Human Resources Committee
[4] Health, Safety and Environment Committee
[5] 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, natural gas liquids and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
GJ	gigajoules
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
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
NGLs	natural gas liquids
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 U.S. dollars at Cushing, Oklahoma

OFFICERS AND KEY PERSONNEL

CANADA

Lorenzo Donadeo, P.Eng.
Chief Executive Officer

Anthony Marino, P.Eng.
President & Chief Operating Officer

John D. Donovan, FCA
Executive Vice President Business Development

Curtis W. Hicks, CA
Executive Vice President & Chief Financial Officer

Mona Jasinski, M.B.A., C.H.R.P.
Executive Vice President People

Terry Hergott, CMA
Vice President Marketing

Michael Kaluza, P.Eng.
Vice President Canada Business Unit

Daniel Goulet, P.Eng.
Director Corporate HSE

Dion Hatcher, P.Eng.
Director Alberta Foothills – Canada Business Unit

Bryce Kremnica, P.Eng.
Director Field Operations – Canada Business Unit

Dean N. Morrison, CFA
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

Jenson Tan, P.Eng.
Director New Ventures

Robert (Bob) J. Engbloom, LL.B
Corporate Secretary

UNITED STATES

Daniel Anderson
Managing Director – U.S. Business Unit

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

EUROPE

Gerard Schut, P.Eng.
Vice President European Operations

Darcy Kerwin, P.Eng.
Managing Director - France Business Unit

Neil Wallace
Managing Director - Netherlands Business Unit

Albrecht Moehring
Managing Director - Germany Business Unit

AUSTRALIA

Bruce D. Lake, P.Eng.
Managing Director
Australia Business Unit

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Royal Bank of Canada

The Bank of Nova Scotia

Canadian Imperial Bank of Commerce

Bank of Montreal

National Bank of Canada

Wells Fargo Bank N.A., Canadian Branch

Alberta Treasury Branches

La Caisse Centrale Desjardins du Québec

HSBC Bank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

Citibank N.A., Canadian Branch - Citibank Canada

Union Bank, Canada Branch

Bank of America N.A., Canada Branch

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

Dean Morrison, Director Investor Relations

VERMILION
ENERGY

EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

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