VERMILION ENERGY

Q2 2015

SECOND QUARTER MANAGEMENT'S DISCUSSION & ANALYSIS

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

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

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 crude 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 crude 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.

MESSAGE TO SHAREHOLDERS

After appearing to reach some degree of range-bound stability during the second quarter, crude oil prices have recently come under renewed pressure as a result of a number of macroeconomic uncertainties. Although this price environment poses significant challenges for many energy sector participants, Vermilion remains comparatively well-positioned given our disciplined approach to financial management and our commodity diversification. In particular, our exposure to European natural gas markets, where fundamentals and pricing remain strong, is a key advantage differentiating Vermilion from its competitors.

As current European natural gas prices remain nearly triple those in Canada, a significant part of our strategic focus has been on maximizing our exposure to this advantageously priced commodity. In 2014, we expanded our European natural gas production by nearly 50% with our entry into Germany, a producing region with a long history of development activity and strong market fundamentals. As detailed later in this Message (see German Farm-In), we have further expanded our European natural gas opportunities by entering into an 850,000 acre farm-in in the key German producing basin. In addition, we have received a conditional award for a 2.35 million acre position in the underexploited Croatian portion of the Pannonian basin (see Croatian Exploration Block Award). With continued organic growth in Netherlands natural gas production, combined with forthcoming natural gas production from our Corrib project in Ireland, European natural gas will continue to increase in prominence for Vermilion.

Our international diversification and associated exposure to Brent-based crude oil pricing continues to favorably distinguish us from our North America-focused competitors. This advantage is illustrated by the operating netback in the first half of 2015 for our Brent-based crude oil sales in Australia and France, which was a blended $49.11/boe, as compared to the operating netback of $41.23/boe for our WTI-based crude oil sales in North America.

In February 2015, we announced a reduction in our 2015 exploration and development ("E&D") capital program to $415 million in response to the significant decrease in crude oil prices that began in mid-2014. Following a comprehensive review of our E&D capital opportunities, we have elected to increase our 2015 E&D capital program to $485 million, an increase of $70 million from our previous capital guidance of $415 million (but less than our original 2015 E&D capital budget of $525 million and 2014 E&D capital expenditures of $688 million). The majority of this increase is associated with the reinstatement of a two-well Australia sidetrack program. The strong economics of this program, coupled with current services pricing advantages and operational efficiencies associated with drilling the wells outside of cyclone season, support our decision to proceed with this project. Vermilion also intends to drill and complete two additional (1.8 net) Mannville condensate-rich natural gas wells and tie-in a third Mannville well. Modest incremental funding has been made available for additional highly economic workovers in France and Canada, and the revised capital program also reflects a minor increase in capital for Ireland as we ramp up for first gas production. We remain on target to achieve our original full year 2015 production guidance of 55,000 to 57,000 boe/d. Based on a mid-fourth quarter start-up for Corrib natural gas production and only modest production contributions in 2015 from our incremental capital, we consider it more likely that annual production will come in closer to the lower end of our guidance range. This would still represent year-over-year production growth exceeding 10%, supported by consolidated organic production growth in each successive quarter of 2015.

In late 2014, we initiated a Profitability Enhancement Program ("PEP") to systematically identify cost savings and efficiency opportunities company-wide. Prior installments of PEP achieved strong results in both the 1998 industry downturn and the financial crisis of 2008-2009. Based on savings identified to-date, this iteration of PEP is expected to result in cost savings related to capital spending, operating expense and G&A estimated at between $60 and $70 million for full-year 2015.

Results from our European development activities have exceeded our expectations. In late April, we started production from the four (4.0 net) wells we drilled in the Champotran field in the Paris Basin in France in Q1 2015. These wells contributed approximately 800 boe/d to our second quarter average production rate, and are producing at rates that are better than anticipated. This was our third drilling program in the Champotran field since 2013, with a cumulative total of 13 wells, at a 100% success rate. After-tax rates of return associated with our Champotran oil drilling program remain in excess of 100%(2) at today's oil prices. The remainder of our 2015 capital activities in France will continue to focus on highly economic workovers and optimization projects, as well as infrastructure and facility maintenance. During the second quarter, we successfully restored approximately 2 mmcf/d (330 boe/d) of shut-in natural gas production from our Vic Bilh field.

In the Netherlands, we drilled two (1.9 net) wells during the quarter on the Slootdorp concession, in the province of North Holland. Both wells were successful, encountering more natural gas pay than expected. The first well, Slootdorp-06, encountered 70 meters of net natural gas pay in the Slochteren formation of the Rotliegend group. The second well, Slootdorp-07, encountered 41 meters of net natural gas pay in two separate intervals in the Zechstein Carbonate. Gross stabilized test flow rates(3) were 23.1 mmcf/d (3,850 boe/d) for Slootdorp-06 and 11.9 mmcf/d (2,000 boe/d) and 2.4 mmcf/d (400 boe/d), respectively, for the lower and upper Zechstein intervals of Slootdorp-07. Both wells are currently on sales during an extended production test to size additional production equipment. The wells are producing at a facility-restricted combined rate of 21 mmcf/d (3,500 boe/d) net. We completed planned major facility maintenance at the Garijp Treatment Centre in late June, which reduced production in the quarter by approximately 2,400 mcf/d (400 boe/d). The shutdown went as intended and the facility returned to service in late June.

In our non-operated German producing assets, our partner (ExxonMobil Production Deutschland GmbH) finished drilling and completing the Burgmoor Z3a well (25% net interest to Vermilion). The well was placed on production subsequent to the quarter and is currently producing at a rate of approximately 1.4 mmcf/d (230 boe/d), net to Vermilion.

At our non-operated Corrib project in Ireland, all natural gas terminal systems have now been commissioned. Following minor remaining compressor maintenance, operator Shell E&P Ireland Limited ("SEPIL") expects to declare all wells, facilities and transport systems (both offshore and onshore) ready for service by the end of August. SEPIL conducted a workover and production test of the Corrib P2 well during July, achieving a stabilized flow rate of 107 mmcf/d (17,830 boe/d)(3) gross. The P2 well is expected to be tied-in to the subsea production system during August, providing additional back-up to augment the deliverability of the other five wells in the Corrib field. With respect to remaining regulatory approvals, a Final Determination for the Corrib Industrial Emissions License ("IEL") from the Irish Environmental Protection Agency ("EPA") and a Ministerial Consent from Ireland's Department of Communications, Energy and Natural Resources must be received prior to commencing natural gas production. In accordance with statutory guidelines on applicable review periods, the EPA is expected to issue its Final Determination on the IEL on or before mid-September. We now estimate that the Ministerial Consent process will be completed, and that production will commence, in the early-to-mid fourth quarter of 2015. Production at Corrib is expected to increase over the first six months after first gas to peak production levels estimated at approximately 58 mmcf/d (approximately 9,700 boe/d), net to Vermilion. Upon commencement, Corrib production will further increase Vermilion's exposure to advantageously priced European natural gas.

While the final regulatory approvals are taking longer than we expected, we believe that we are very near the end of the regulatory process for Corrib. Our ability to maintain our 2015 production guidance (originally set in March 2014), despite foregoing approximately 3,000 net boe/d of planned calendar year average production from Corrib, is indicative of the operational and asset strength of our company. Moreover, we have maintained this production guidance while reducing 2015 capital expenditures by more than $200 million (over 30%) from 2014 levels.

With the compelling opportunities in our overseas business units, and the significant operating flexibility offered by our Canadian asset base, planned activity levels for Canada in 2015 are less than in prior years. That being said, our Canadian opportunities continue to offer robust economics with the Cardium light-oil resource play generating capital investment rates of return of approximately 30%(2). Results to-date have been strong, with better-than-forecasted production volumes on our two-mile extended reach horizontal wells. In Q1 2015, we participated in the drilling of only seven (3.1 net) Cardium wells, which represented our planned Cardium drilling activities for 2015 (compared to 30 to 50 net wells in previous years). During Q2, we focused predominately on the completion and tie-in of previously drilled wells. Our Mannville condensate-rich conventional natural gas play remains the most economic play in our Canadian portfolio with current rates of return in excess of 100%(2). During Q1 2015, we participated in drilling 13 (8.9 net) wells followed by an additional one (0.5 net) well in Q2. In total, we plan on drilling approximately 30 (17.8 net) Mannville wells in 2015. During the second quarter, we also concluded a significant infrastructure project that included the expansion of a compressor station as well as the construction of a 22 km pipeline. This infrastructure will play a critical role in supporting the continued growth of the Mannville play. In Saskatchewan, we had previously reduced our drilling activity to five (4.1 net) wells for 2015, all of which were drilled in the first quarter. New well results in our downdip Midale play in southeast Saskatchewan have been better than we expected at the time we entered this area in 2014. Duvernay drilling activities have been deferred to beyond 2015 as we monitor the performance of our two appraisal wells drilled in 2014. In Alberta, we continue to be negatively impacted by plant capacity restrictions and interruptible service curtailments on the NGTL system, with approximately 1,700 boe/d of production offline during the second quarter.

In the United States, we drilled one gross (1 net) well in our Turner Sand resource play in the eastern Powder River Basin during the second quarter. We expect to complete this well during the third quarter of 2015.

To maintain financial flexibility in this commodity price environment, we further increased our existing revolving credit facilities from $1.75 billion to $2 billion during the second quarter. Taking into account this most recent expansion to our credit facility, we have approximately $775 million of borrowing capacity available. The facility, which matures in May 2019, is fully revolving up to the date of maturity and is subject to standard form covenants (discussed in the "Financial Position Review" section of our MD&A). We are, and we expect to continue to remain, in compliance with all applicable debt covenants, and expect to maintain our current dividend of $0.215 per share per month ($2.58 per share per year). We currently anticipate our balance sheet leverage to remain at current levels assuming consistent commodity prices, and then to naturally de-lever with the addition of FFO from our Corrib asset starting in the fourth quarter of 2015 and into 2016. While our current debt-to-cash flow ratio is higher than our targeted levels, it remains lower than the average debt ratio of our peer group. Our conservative financial management continues to provide us with the flexibility to manage our business effectively and provide continued growth and returns for shareholders in this challenging price environment.

During Q2, Vermilion was pleased to announce that for a sixth consecutive year, it has been recognized by the Great Place to Work® Institute as a Best Workplace in Canada and France. Vermilion was also recognized for a second consecutive year as a Best Workplace in the Netherlands in 2015, after becoming eligible for ranking in 2014. Vermilion is the only energy company in its category to rank on the Best Workplaces lists in Canada and the Netherlands, and the highest scoring energy company on the Best Workplaces list in France.

Vermilion was recently ranked 15th by Corporate Knights on the Future 40 Responsible Corporate Leaders in Canada list (the highest ranking for an oil and gas company, and improved from our debut ranking of 32nd last year). We were also named Top International Producer of the year by the Explorers and Producers Association of Canada. This recognition reflects Vermilion's continued focus on achieving robust shareholder returns combined with environmental, social and governance performance. Our non-financial initiatives and performance are also articulated in the Company's annual Carbon Disclosure Project (CDP) submissions and in our Sustainability Report (http://www.vermilionenergy.com/sustainability). Strong workplace practices and a culture that respects both people and communities are key elements in our success.

The management and directors of Vermilion continue to hold approximately 6% of the outstanding shares and remain committed to delivering superior rewards to all stakeholders. In spite of the challenges posed by the current business environment, we continue to believe that Vermilion is situated for long-term, diversified growth. We remain confident that the assets in our portfolio can support organic growth for future years, and in the current environment, we also find ourselves well positioned to take advantage of potential acquisition activity in both North American and international markets. Our long-term focus on the creation of real value through our technical capabilities, combined with our conservative financial approach and patience, should allow us to compete and transact for the benefit of our existing shareholders if suitable opportunities arise.

German Farm-In

Subsequent to the end of the second quarter, we entered into a definitive farm-in agreement (the "Farm-in" or the "Agreement") with Mobil Erdgas-Erdöl GmbH ("MEEG") and BEB Erdgas und Erdöl GmbH & Co.KG ("BEB"). MEEG is 100% held by ExxonMobil and BEB is jointly held by ExxonMobil and Royal Dutch Shell. ExxonMobil Production Deutschland GmbH ("EMPG") currently operates and manages both MEEG's and BEB's interests in the exploration licenses involved in the Farm-in. The Agreement, signed July 27, 2015 and with an anticipated closing date of January 1, 2016, remains subject to customary conditions and regulatory approvals.

The Farm-in will provide Vermilion participating interest in 19 onshore exploration licenses in northwest Germany, comprising approximately 850,000 net acres of oil and natural gas rights (100% undeveloped) (the "Assets"). Under the terms of the Agreement, Vermilion will acquire the Assets (which represent 50% of MEEG's and BEB's current interests in these licenses) in exchange for committing to the financial carry of the remaining 50% of MEEG's and BEB's interests in 11 gross (6 net) exploratory wells over the next five years. At present, approximately 75 exploratory and semi-exploratory leads and prospects have been identified in the Rotliegend, Carboniferous, Triassic and Zechstein formations on these lands. Eleven of the 19 licenses are currently operated by EMPG, which will transfer operatorship for the exploration phase to Vermilion. The Agreement also grants Vermilion proportional ownership to EMPG proprietary data spanning the Assets. No existing oil or natural gas production is being acquired by Vermilion in the Farm-in.

The Farm-in provides Vermilion with a large, nearly contiguous land block in the heart of the North German Basin. This basin has cumulative production of more than two billion barrels of oil and 34 trillion cubic feet of natural gas since its discovery, representing approximately 97% of Germany's historical onshore production. We believe that the Assets are prospective for both oil and natural gas. The Farm-in follows our entry in early 2014 into the exploration and production business in Germany, a jurisdiction with a long history of oil and natural gas development activity, a consistent fiscal framework and low political risk. The Assets are a natural and synergistic expansion to our existing German and Netherlands portfolios, and share the same subsurface genre and development approach. We believe that our capability in conventional oil and natural gas exploration and production in onshore Europe, coupled with our track record of accretive European consolidation, positions us for future development and expansion opportunities in both Germany and the greater European region.

Croatian Exploration Block Award

On June 3, 2015, we were conditionally awarded four exploration blocks in northeast Croatia near the Hungarian border, by the Croatian Hydrocarbon Agency. This award remains subject to successful execution of a definitive contract acceptable to both Vermilion and the Government of the Republic of Croatia. The four exploration blocks consist of approximately 2.35 million gross acres with a substantial portion of the acreage located near existing crude oil and natural gas fields. Capital commitments on the four blocks are modest and back-loaded. The initial 5-year exploration period consists of two phases with an option to relinquish the blocks following the initial 3-year phase. In aggregate, our capital commitments, excluding an initial bonus payment of €1.3 million, total approximately €7.3 million over the three-year mandatory phase, followed by an additional €11.6 million during the remaining two-year optional phase.

("Lorenzo Donadeo")

Lorenzo Donadeo
Chief Executive Officer
August 6, 2015

(1) The above discussion includes additional GAAP and non-GAAP measures which may not be comparable to other companies. Please see the "ADDITIONAL AND NON-GAAP FINANCIAL MEASURES" section of Management's Discussion and Analysis.
(2) Economics calculated using the following commodity price deck assumptions: $50/bbl WTI; $55/bbl Dated Brent; $2.85/mmbtu AECO; CAD/USD 1.30; CAD/EUR 1.40.
(3) Slootdorp-06 (Slochteren) production test was performed over an 18-day test period at a maximum choke of 64/64" with approximately 45% drawdown over the test period. Slootdorp-07 (lower zone – Z2) production test was performed over a 4-hour test period at a maximum choke of 36/64" with approximately 35% drawdown over the test period. Slootdorp-07 (upper zone – Z3) production test was performed over a 12-hour test period at a maximum choke of 16/64" with approximately 40% drawdown over the test period. This test result is not necessarily indicative of long-term performance or of ultimate recovery.
(4) Corrib P2 well produces from the Sherwood sandstones. The production test was performed over a 12-hour period at a maximum choke of 80/64", achieving a peak production rate of 113 mmcf/d and a stabilized flow rate of 107 mmcf/d with approximately 30% drawdown over the test period. This test result is not necessarily indicative of long-term performance or of ultimate recovery.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A"), dated August 6, 2015, of Vermilion Energy Inc.'s ("Vermilion", "We", "Our", "Us" or the "Company") operating and financial results as at and for the three and six months ended June 30, 2015 compared with the corresponding periods in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three and six months ended June 30, 2015 and the audited consolidated financial statements for the year ended December 31, 2014 and 2013, together with accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

The unaudited condensed consolidated interim financial statements for the three and six months ended June 30, 2015 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 North America, Europe, and Australia. We manage our business through our Calgary head office and our international business unit offices.

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

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

GUIDANCE

We first issued 2015 capital expenditure guidance of $525 million on December 8, 2014. We subsequently adjusted our 2015 capital expenditure guidance to $415 million on February 27, 2015, in response to the continued weakness in commodity prices. That reduction reflected lower planned activity levels, including the deferral of our Australian drilling campaign. On August 10, 2015 we announced an increase in our capital expenditure guidance of $70 million to $485 million following the reinstatement of the Australian drilling campaign as well as additional funding for projects in Canada, France and Ireland. We are maintaining our previous production guidance of 55,000-57,000 boe/d, albeit towards the lower end of our guidance range due to later-than-originally expected first gas from Corrib.

The following table summarizes our 2015 guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2015 - Guidance			
2015 Guidance	December 8, 2014	525	55,000 to 57,000
2015 Guidance	February 27, 2015	415	55,000 to 57,000
2015 Guidance	August 10, 2015	485	55,000 to 57,000

SHAREHOLDER RETURN

Vermilion strives to provide investors with reliable and growing dividends in addition to sustainable, global production growth. The following table, as of June 30, 2015, 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	$2.58	$7.41	$11.97
Capital appreciation per Vermilion share	-$20.30	$7.98	$20.28
Total return per Vermilion share	-23.9%	33.5%	95.8%
Annualized total return per Vermilion share	-23.9%	10.1%	14.4%
Annualized total return on the S&P TSX High Income Energy Index	-32.2%	-2.9%	0.4%

(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		Six Months Ended		% change
	Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Jun 30, 2015	Jun 30, 2014	2015 vs. 2014
Production								
Crude oil (bbls/d)	28,916	28,181	30,184	3%	(4%)	28,550	28,759	(1%)
NGLs (bbls/d)	3,867	3,039	2,892	27%	34%	3,455	2,518	37%
Natural gas (mmcf/d)	114.29	115.00	114.08	(1%)	-	114.64	108.73	5%
Total (boe/d)	51,831	50,386	52,089	3%	-	51,113	49,398	3%
Build (draw) in inventory (mbbl)	(121)	383	67			262	(31)	
Financial metrics								
Fund flows from operations ($M)	129,496	120,795	216,076	7%	(40%)	250,291	421,439	(41%)
Per share ($/basic share)	1.18	1.12	2.05	5%	(42%)	2.31	4.05	(43%)
Net earnings ($M)	6,813	1,275	53,993	434%	(87%)	8,088	156,781	(95%)
Per share ($/basic share)	0.06	0.01	0.51	500%	(88%)	0.07	1.51	(95%)
Cash flows from operating activities ($M)	134,668	22,647	149,592	495%	(10%)	157,315	327,830	(52%)
Net debt ($M)	1,377,902	1,388,603	1,168,998	(1%)	18%	1,377,902	1,168,998	18%
Cash dividends ($/share)	0.645	0.645	0.645	-	-	1.290	1.290	-
Activity								
Capital expenditures ($M)	90,173	174,311	135,073	(48%)	(33%)	264,484	331,448	(20%)
Acquisitions ($M)	480	35	381,139	1,271%	(100%)	515	559,366	(100%)
Gross wells drilled	5.00	29.00	13.00			34.00	37.00	
Net wells drilled	3.61	20.04	6.72			23.65	25.55	

Operational review

- Recorded consolidated average production of 51,831 boe/d during Q2 2015, which was a 3% increase over Q1 2015 as a result of production growth in France and Canada driven primarily by new wells on production, partially offset by decreased production in the Netherlands due to planned facility maintenance. As compared to Q2 2014, production remained relatively consistent. Steady production, coupled with a draw in inventory of 121,000 bbls in Q2 2015, resulted in higher volumes sold versus the comparable quarters.
- Increased consolidated average production to 51,113 for the six months ended June 30, 2015, a 3% increase versus the same period in 2014 primarily due to production growth in Canada and France, partially offset by decreased production in the Netherlands and Australia. In Canada, production growth of 9% year-over-year was achieved through continued development of the Cardium and Mannville plays in Alberta, combined with six months of production from southeast Saskatchewan, as compared to two months of production included in the 2014 period following our acquisition in April 2014 of Elkhorn Resources Inc. In France, production increased 12% following our successful Champotran drilling program and workovers, as well as the resumption of a portion of previously shut-in natural gas production at Vic Bilh. These increases were offset by production decreases in the Netherlands and Australia due to the planned maintenance shutdown at our largest gas processing facility in the Netherlands, as well as active management to control inventory levels and meet marketing schedules in Australia.
- Activity during the quarter included capital expenditures totalling $90.2 million, evenly distributed between Canada, Ireland, France, and the Netherlands. In Canada, capital expenditures totalling $21.9 million were 81% lower than the $114.8 million incurred in Q1 2015 due to spring breakup and were related to facility work and the drilling of one (0.5 net) well compared to 16.0 net wells in Q1 2015. In France, capital expenditures totalled $16.7 million with activity focused on the completion of the Champotran drilling campaign and accretive workovers. In Ireland, capital expenditures of $20.3 million were incurred, the majority of which related to facility commissioning and subsurface activities. In the Netherlands, capital expenditures of $18.9 million were significantly higher than the $4.3 million incurred in Q1 2015 and related to the drilling of 1.9 net wells, while no wells were drilled in Q1 2015.

Financial review

Net earnings

- Net earnings for Q2 2015 were $6.8 million ($0.06/basic share) as compared to net earnings of $1.3 million ($0.01/basic share) in Q1 2015. The increase is attributable to higher petroleum and natural gas sales driven by higher commodity prices and higher sales volumes, as well as a $7.2 million gain on derivative instruments (compared to a loss of $13.7 million in Q1 2015). These increases were partially offset by higher operating costs and depletion and depreciation, both of which were driven by inventory drawdowns in Australia, and the absence of the Q1 2015 recognition of the recovery of costs in France. In Q1 2015, Vermilion recognized $31.8 million (before taxes) following a judgment which awarded Vermilion costs incurred as a result of an oil spill at the Ambès oil terminal in France that occurred in 2007 shortly after Vermilion acquired the asset.
- Net earnings for the three and six months ended June 30, 2015 decreased by $47.2 million and $148.7 million, respectively, versus the comparative periods in 2014. These decreases were driven primarily by lower petroleum and natural gas sales as a result of lower commodity prices, and were partially offset by decreases in royalties and taxes. In the six months ended June 30, 2015, the decrease in net earnings was also minimized by the recovery of costs in France recognized in Q1 2015.

Cash flows from operating activities

- Cash flows from operating activities increased as compared to Q1 2015, driven primarily by higher volumes sold and higher realized prices, as well as significant timing differences pertaining to working capital.
- Cash flows from operating activities decreased by 10% and 52% for the three and six months ended June 30, 2015, respectively, versus the comparable periods in 2014. The decreases primarily related to lower sales due to lower commodity prices, partially offset by timing differences pertaining to working capital, foreign exchange gains and lower royalties.

Fund flows from operations

- Generated fund flows from operations of $129.5 million during Q2 2015, an increase of 7% versus Q1 2015. This quarter-over-quarter increase was the result of higher sales, driven by higher volumes and prices, and lower tax expense. This was partially offset by higher operating expenses, as well as the absence of the recovery of costs resulting from the oil spill at the Ambès terminal in France that occurred in 2007, which was recognized in Q1 2015.
- Fund flows from operations decreased 40% and 41% for the three and six months ended June 30, 2015, respectively, versus the comparable periods in 2014. These decreases were primarily driven by lower crude oil pricing, partially offset by higher sold volumes in Australia (due to an inventory draw in Q2 2015), as well as favorable royalty and tax variances, consistent with lower commodity prices. The decrease in fund flows from operations for the six months ended June 30, 2015, was further minimized by the previously mentioned recovery of costs in France.

Net debt

- Net debt increased by $112.3 million to $1.38 billion for the period ended June 30, 2015 due to capital expenditures in Canada and Ireland coupled with the decrease in fund flows from operations, driven by weaker commodity prices in the first half of 2015.

Dividends

- Declared dividends remained consistent at $0.215 per common share per month during the second quarter of 2015, totalling $0.645 per common share and $1.290 per common share for the three and six months ended June 30, 2015, respectively.

COMMODITY PRICES

	Three Months Ended			% change		Six Months Ended		% change
	Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Jun 30, 2015	Jun 30, 2014	2015 vs. 2014
Average reference prices								
WTI (US $/bbl)	57.94	48.63	102.99	19%	(44%)	53.29	100.84	(47%)
Edmonton Sweet index (US $/bbl)	55.08	41.83	96.85	32%	(43%)	48.46	93.65	(48%)
Dated Brent (US $/bbl)	61.92	53.97	109.63	15%	(44%)	57.95	108.93	(47%)
AECO ($/GJ)	2.52	2.60	4.44	(3%)	(43%)	2.56	4.93	(48%)
TTF ($/GJ)	7.94	8.25	7.91	(4%)	-	8.10	9.02	(10%)
TTF (€/GJ)	5.84	5.91	5.27	(1%)	11%	5.87	6.01	(2%)
Average foreign currency exchange rates								
CDN $/US $	1.23	1.24	1.09	(1%)	13%	1.24	1.10	13%
CDN $/Euro	1.36	1.40	1.50	(3%)	(9%)	1.38	1.50	(8%)
Average realized prices ($/boe)								
Canada	40.59	35.81	71.56	13%	(43%)	38.24	70.55	(46%)
France	71.96	64.33	117.29	12%	(39%)	68.52	117.41	(42%)
Netherlands	47.63	48.60	48.14	(2%)	(1%)	48.13	56.06	(14%)
Germany	43.31	45.21	45.36	(4%)	(5%)	44.27	49.50	(11%)
Australia	80.87	83.80	126.87	(3%)	(36%)	81.60	127.11	(36%)
United States	60.57	48.79	-	24%	100%	54.07	-	100%
Consolidated	54.65	47.17	82.96	16%	(34%)	51.19	85.70	(40%)
Production mix (% of production)								
% priced with reference to WTI	27%	28%	30%			27%	27%	
% priced with reference to AECO	21%	20%	18%			21%	18%	
% priced with reference to TTF	16%	18%	18%			17%	19%	
% priced with reference to Dated Brent	36%	34%	34%			35%	36%	

Reference prices

- Evidence of slowing production growth and stronger demand helped support oil prices in the second quarter of 2015. Compared to Q1 2015, the three months ended June 30, 2015 showed a 19% increase for WTI and a 15% increase for Dated Brent.
- The second quarter of 2015 proved to be a particularly strong quarter for Edmonton Sweet index pricing as strong refining demand and maintenance work combined to tighten supply/demand fundamentals. For the three months ending June 30, 2015, the Edmonton Sweet index was up 32% versus the previous quarter, but was still 43% lower year-over-year.
- AECO natural gas prices were relatively flat quarter-over-quarter, but were below last year’s levels. AECO averaged C$2.52/GJ in Q2 2015, which is just 3% lower than the previous three months, but 43% lower year-over-year.
- TTF natural gas averaged just slightly lower in Q2 2015 versus Q1 2015 despite seasonal dynamics. Lower inventories and maintenance were the main factors that helped to keep TTF natural gas prices firm throughout the second quarter, ending just 1% lower quarter-over-quarter and 11% higher versus the same quarter last year in Euro terms.
- Despite a rather volatile quarter, the Canadian dollar averaged nearly the same in Q2 2015 as in Q1 2015 versus the US dollar at 1.23 CDN$/US$. The low commodity price environment and broader US dollar strength continues to limit Canadian dollar strength; however, versus the Euro, the Canadian dollar posted a modest increase quarter-over-quarter. In Q2 2015, the CDN $/Euro averaged 1.36 versus 1.40 in Q1 2015 and 1.50 in Q2 2014.

Realized prices

- Consolidated realized price increased by 16% for Q2 2015 as compared to Q1 2015. This increase was the result of improving crude oil pricing, coupled with relatively consistent natural gas pricing.
- Consolidated realized price for the three and six months ended June 30, 2015 decreased by 34% and 40%, respectively, as compared to the comparable periods in 2014. These decreases were driven by a decrease in crude oil pricing, as well as a decrease in North American natural gas pricing.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Six Months Ended			
	Jun 30, 2015		Mar 31, 2015		Jun 30, 2014		Jun 30, 2015		Jun 30, 2014	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	264,331	54.65	195,885	47.17	387,684	82.96	460,216	51.19	768,867	85.70
Royalties	(16,111)	(3.33)	(16,424)	(3.95)	(29,013)	(6.21)	(32,535)	(3.62)	(53,037)	(5.91)
Petroleum and natural gas revenues	248,220	51.32	179,461	43.22	358,671	76.75	427,681	47.57	715,830	79.79
Transportation expense	(10,883)	(2.25)	(9,540)	(2.30)	(12,032)	(2.57)	(20,423)	(2.27)	(21,893)	(2.44)
Operating expense	(58,616)	(12.12)	(43,851)	(10.56)	(58,213)	(12.46)	(102,467)	(11.40)	(116,199)	(12.95)
General and administration	(14,505)	(3.00)	(13,560)	(3.27)	(17,762)	(3.80)	(28,065)	(3.12)	(32,229)	(3.59)
PRRT	(3,371)	(0.70)	(2,354)	(0.57)	(12,699)	(2.72)	(5,725)	(0.64)	(32,938)	(3.67)
Corporate income taxes	(17,344)	(3.59)	(17,623)	(4.24)	(32,635)	(6.98)	(34,967)	(3.89)	(71,238)	(7.94)
Interest expense	(14,550)	(3.01)	(13,298)	(3.20)	(12,334)	(2.64)	(27,848)	(3.10)	(23,794)	(2.65)
Realized gain on derivative instruments	3,081	0.64	6,257	1.51	2,419	0.52	9,338	1.04	5,059	0.56
Realized foreign exchange (loss) gain	(2,740)	(0.57)	3,306	0.78	587	0.12	566	0.06	(1,454)	(0.16)
Realized other income	204	0.04	31,997	7.70	74	0.02	32,201	3.58	295	0.03
Fund flows from operations	129,496	26.76	120,795	29.07	216,076	46.24	250,291	27.83	421,439	46.98

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

($M)	Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	2015 vs. 2014
Fund flows from operations – Comparative period	120,795	216,076	421,439
Sales volume variance:			
Canada	1,950	(10,845)	15,826
France	12,285	6,751	(1,469)
Netherlands	(2,407)	(5,585)	(12,187)
Germany	(313)	30	4,606
Australia	38,956	29,345	(31,213)
United States	(127)	677	1,349
Pricing variance on sold volumes:			
WTI	12,700	(50,424)	(108,609)
AECO	(1,118)	(10,708)	(24,490)
Dated Brent	7,474	(81,710)	(141,350)
TTF	(954)	(884)	(11,114)
Changes in:			
Royalties	313	12,902	20,502
Transportation	(1,343)	1,149	1,470
Operating expense	(14,765)	(403)	13,732
General and administration	(945)	3,257	4,164
PRRT	(1,017)	9,328	27,213
Corporate income taxes	279	15,291	36,271
Interest	(1,252)	(2,216)	(4,054)
Realized derivatives	(3,176)	662	4,279
Realized foreign exchange	(6,046)	(3,327)	2,020
Realized other income	(31,793)	130	31,906
Fund flows from operations – Current period	129,496	129,496	250,291

Fund flows from operations of $129.5 million during Q2 2015 represented an increase of 7% versus Q1 2015. This quarter-over-quarter increase was principally the result of higher sales volumes and stronger crude oil pricing. Sales increased by $68.4 million, which included a $50.3 million sales volumes variance driven by increased sales in Australia ($39.0 million) and France ($12.3 million). Both Australia and France were impacted by inventory variances, where Australia had an inventory draw of 162,000 bbls (as compared to a build of 281,000 bbls) and France's inventory increased by 41,000 bbls (as compared to a build of 102,000 bbls). The increase in fund flows from operations was further impacted by an $18.1 million favorable pricing variance driven by higher crude oil prices. Higher sold volumes and crude oil pricing was partially offset by higher operating expenses resulting from the recognition of inventoried operating costs in Australia, as well as the absence of the previously mentioned recovery of costs in France.

Fund flows from operations decreased by 40% and 41% for the three and six months ended June 30, 2015, respectively, versus the comparable periods in the prior year. This decrease was primarily driven by unfavorable crude oil and natural gas pricing variances, partially offset by favorable royalty and tax variances. For the three months ended June 30, 2015, the decrease in fund flows from operations was further offset by a favorable sales variance of $20.4 million driven by increased sold volume in Australia. For the six months ended June 30, 2015, the decrease in fund flows from operations was further impacted by a $23.1 million unfavorable sales variance, driven by a build in inventory of 262,000 bbls (as compared to a draw of 31,000 bbls in the comparative period), partially offset by the previously mentioned recovery of costs in France.

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 the 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 Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	% change Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Six Months Ended Jun 30, 2015	Jun 30, 2014	% change 2015 vs. 2014
Production								
Crude oil (bbls/d)	10,182	10,893	12,676	(7%)	(20%)	10,535	11,065	(5%)
NGLs (bbls/d)	3,755	2,976	2,796	26%	34%	3,367	2,435	38%
Natural gas (mmcf/d)	64.66	61.78	57.59	5%	12%	63.23	53.58	18%
Total (boe/d)	24,713	24,165	25,070	2%	(1%)	24,441	22,430	9%
Production mix (% of total)								
Crude oil	41%	45%	51%			43%	49%	
NGLs	15%	12%	11%			14%	11%	
Natural gas	44%	43%	38%			43%	40%	
Activity								
Capital expenditures ($M)	21,881	114,849	36,968	(81%)	(41%)	136,730	151,907	(10%)
Acquisitions ($M)	384	35	381,326			419	386,094	
Gross wells drilled	1.00	25.00	9.00			26.00	29.00	
Net wells drilled	0.50	16.04	3.29			16.54	18.26	

Production

- Production in Canada increased by 2% quarter-over-quarter and decreased by 1% year-over-year. Year-to-date average production increased by 9%, primarily attributable to strong organic production growth in our Mannville condensate-rich gas resource play and production associated with our acquisition of Elkhorn Resources Inc. completed in April 2014. Q2 2015 volumes were negatively impacted by approximately 1,700 boe/d of production offline as a result of plant capacity restrictions and interruptible service curtailments on the NGTL system. We anticipate having the majority of the curtailed volumes online during Q3 2015 with full productive capability expected to be achieved during Q4 2015.
- Cardium production averaged more than 9,300 boe/d in Q2 2015, a 5% decrease quarter-over-quarter, with some non-operated volume currently constrained due to pipeline restrictions.
- Mannville production averaged more than 5,600 boe/d in Q2 2015, a 15% increase quarter-over-quarter. As with Cardium production, non-operated Mannville volume was constrained due to pipeline restrictions.
- Production from our southeast Saskatchewan assets averaged approximately 3,300 boe/d in Q2 2015, an increase of 15% quarter-over-quarter attributable to increased natural gas and NGL sales. The North Portal Gas Plant was commissioned late in Q1 2015. The plant will enable the processing of approximately 5,500 mcf/d (920 boe/d) net of natural gas which was previously being flared.

Activity review

- Vermilion participated in the drilling of one (0.5 net) non-operated well during Q2 2015.

  Cardium
  - During Q2 2015, three (1.5 net) non-operated wells were brought on production.
  - In 2015, we plan to drill or participate in seven (3.1 net) wells executed in Q1 2015, and complete, equip and tie-in an additional 8.2 net wells which were drilled in 2014.

  Mannville
  - During Q2 2015, we completed four (3.5 net) operated wells and brought three (3.0 net) operated wells on production. We also participated in the drilling of one (0.5 net) non-operated well and one (0.4 net) non-operated well was placed on production.
  - In 2015, we expect to drill or participate in approximately 30 (17.8 net) wells and complete, equip and tie-in an additional 1.0 net well which was drilled in 2014.

  Saskatchewan
  - We drilled and brought on production five (4.1 net) operated Midale wells during Q1 2015, completing our 2015 drilling activity in Saskatchewan.

Financial review

Canada business unit ($M except as indicated)	Three Months Ended Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	% change Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Six Months Ended Jun 30, 2015	Jun 30, 2014	% change 2015 vs. 2014
Sales	91,284	77,884	163,261	17%	(44%)	169,168	286,441	(41%)
Royalties	(5,768)	(8,592)	(18,240)	(33%)	(68%)	(14,360)	(30,903)	(54%)
Transportation expense	(4,469)	(3,942)	(4,024)	13%	11%	(8,411)	(7,122)	18%
Operating expense	(21,534)	(19,099)	(21,179)	13%	2%	(40,633)	(37,789)	8%
General and administration	(5,510)	(4,015)	(6,560)	37%	(16%)	(9,525)	(9,428)	1%
Fund flows from operations	54,003	42,236	113,258	28%	(52%)	96,239	201,199	(52%)
Netbacks ($/boe)								
Sales	40.59	35.81	71.56	13%	(43%)	38.24	70.55	(46%)
Royalties	(2.56)	(3.95)	(7.99)	(35%)	(68%)	(3.25)	(7.61)	(57%)
Transportation expense	(1.99)	(1.81)	(1.76)	10%	13%	(1.90)	(1.75)	9%
Operating expense	(9.58)	(8.78)	(9.28)	9%	3%	(9.19)	(9.31)	(1%)
General and administration	(2.45)	(1.85)	(2.88)	32%	(15%)	(2.15)	(2.32)	(7%)
Fund flows from operations netback	24.01	19.42	49.65	24%	(52%)	21.75	49.56	(56%)
Reference prices								
WTI (US $/bbl)	57.94	48.63	102.99	19%	(44%)	53.29	100.84	(47%)
Edmonton Sweet index (US $/bbl)	55.08	41.83	96.85	32%	(43%)	48.46	93.65	(48%)
Edmonton Sweet index ($/bbl)	67.72	51.92	105.61	30%	(36%)	59.86	102.73	(42%)
AECO ($/GJ)	2.52	2.60	4.44	(3%)	(43%)	2.56	4.93	(48%)

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 increased by 13% quarter-over-quarter as a result of a 30% increase in Edmonton Sweet index pricing in Canadian dollar terms offset by a 3% decrease in AECO pricing. This increase, coupled with relatively consistent production volumes, resulted in a 17% increase in sales.
- On a year-over-year basis, sales per boe decreased by 43% and 46% for the three and six months ended June 30, 2015, largely as the result of weakening crude oil and natural gas pricing. For the three months ended June 30, 2015, the lower pricing was combined with consistent production volumes, resulting in a 44% decrease in sales. For the six months ended June 30, 2015, the decline in commodity prices was partially offset by a 9% increase in production, resulting in a 41% decrease in sales.

Royalties

- Royalties as a percentage of sales for Q2 2015 decreased to 6.3% as compared to Q1 2015 of 11.0% despite higher reference prices (which would typically result in higher royalty rates) due to the timing of when par prices used in the royalty calculations were set. This timing difference resulted in lower crude oil royalty rates for Q2 2015. In addition, an annual favorable gas cost allowance (“GCA”) adjustment in Alberta resulted in gas royalties being in a recovery position for the current quarter.
- Royalties as a percentage of sales for the three and six months ended June 30, 2015 decreased to 6.3% and 8.5% versus 11.2% and 10.8% for the same periods in 2014 due to the impact of lower reference prices on the sliding scale used to determine crude oil royalty rates and the aforementioned favorable GCA adjustment.

Transportation

- Transportation expense relates to the delivery of crude oil and natural gas production to major pipelines where legal title transfers.
- Transportation expense for Q2 2015 was higher than Q1 2015 as a result of higher natural gas liquids and natural gas production.
- Transportation expense for the three and six months ended June 30, 2015 was higher than the same periods in the prior year as a result of incremental trucking costs from Vermilion's Saskatchewan properties, which were acquired in April of 2014.

Operating expense

- Operating expenses were higher for Q2 2015 versus Q1 2015 on both a dollar and per boe basis due to higher road use fees and a higher level of facilities maintenance activity in Saskatchewan.
- Operating expenses were higher on a dollar basis for the three and six months ended June 30, 2015 compared to the same periods in 2014 due to incremental operating expenses associated with Vermilion's Saskatchewan properties, acquired in Q2 2014. This dollar increase resulting from the acquisition was largely offset by a wide range of cost reduction initiatives undertaken in response to commodity price weakness resulting in reduced operating expense on a per boe basis for year-to-date 2015.

General and administration

- General and administration expense fluctuations in Q2 2015 as compared to both Q1 2015 and Q2 2014 were a result of the timing of expenditures.
- Year-over-year, general and administration expense for the six months ended June 30, 2015 was consistent with 2014.

FRANCE BUSINESS UNIT

Overview

- Entered France in 1997 and completed three subsequent acquisitions, including two in 2012.
- Largest oil producer in France, constituting approximately three-quarters of domestic oil production.
- Producing assets include large conventional 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		Six Months Ended		% change
France business unit	Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Jun 30, 2015	Jun 30, 2014	2015 vs. 2014
Production								
Crude oil (bbls/d)	12,746	11,463	11,025	11%	16%	12,108	10,899	11%
Natural gas (mmcf/d)	1.03	-	-	100%	100%	0.52	-	100%
Total (boe/d)	12,917	11,463	11,025	13%	17%	12,194	10,899	12%
Inventory (mbbls)								
Opening crude oil inventory	299	197	238			197	269	
Crude oil production	1,160	1,032	1,003			2,192	1,973	
Crude oil sales	(1,119)	(930)	(1,062)			(2,049)	(2,063)	
Closing crude oil inventory	340	299	179			340	179	
Production mix (% of total)								
Crude oil	99%	100%	100%			99%	100%	
Natural gas	1%	-	-			1%	-	
Activity								
Capital expenditures ($M)	16,697	34,114	37,614	(51%)	(56%)	50,811	75,581	(33%)
Acquisitions ($M)	96	-	-			96	-	
Gross wells drilled	-	4.00	2.00			4.00	4.00	
Net wells drilled	-	4.00	2.00			4.00	4.00	

Production

- Quarter-over-quarter and year-over-year production growth of 13% and 17%, respectively, due to production additions from our 2015 Champotran drilling program and workovers.
- 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 was temporarily shut-in while preparations to transfer to an alternative facility were completed. During Q2 2015, approximately 2 mmcf/d (330 boe/d) of Vic Bilh gas production was restored.

Activity review

- Vermilion drilled four (4.0 net) wells in the Champotran field in the Paris Basin in Q1 2015, completing our planned France drilling program for 2015.
- In 2015, additional activity includes a 26-well workover program and the resumption of sales from a portion of our shut-in natural gas at Vic Bilh, which was brought on-line in Q2 2015.

Financial review

France business unit ($M except as indicated)	Three Months Ended Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	% change Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Six Months Ended Jun 30, 2015	Jun 30, 2014	% change 2015 vs. 2014
Sales	81,627	59,832	124,617	36%	(34%)	141,459	242,177	(42%)
Royalties	(6,620)	(5,102)	(7,796)	30%	(15%)	(11,722)	(15,147)	(23%)
Transportation expense	(3,526)	(3,011)	(5,385)	17%	(35%)	(6,537)	(10,138)	(36%)
Operating expense	(12,102)	(10,826)	(16,550)	12%	(27%)	(22,928)	(32,970)	(30%)
General and administration	(4,874)	(5,111)	(5,559)	(5%)	(12%)	(9,985)	(10,753)	(7%)
Other income	-	31,775	-	(100%)	-	31,775	-	100%
Current income taxes	(9,316)	(14,281)	(24,761)	(35%)	(62%)	(23,597)	(50,025)	(53%)
Fund flows from operations	45,189	53,276	64,566	(15%)	(30%)	98,465	123,144	(20%)
Netbacks ($/boe)								
Sales	71.96	64.33	117.29	12%	(39%)	68.52	117.41	(42%)
Royalties	(5.84)	(5.49)	(7.34)	6%	(20%)	(5.68)	(7.34)	(23%)
Transportation expense	(3.11)	(3.24)	(5.07)	(4%)	(39%)	(3.17)	(4.91)	(35%)
Operating expense	(10.67)	(11.64)	(15.58)	(8%)	(32%)	(11.11)	(15.98)	(30%)
General and administration	(4.30)	(5.49)	(5.24)	(22%)	(18%)	(4.84)	(5.21)	(7%)
Other income	-	34.16	-	(100%)	-	15.39	-	100%
Current income taxes	(8.21)	(15.35)	(23.30)	(47%)	(65%)	(11.43)	(24.25)	(53%)
Fund flows from operations netback	39.83	57.28	60.76	(30%)	(34%)	47.68	59.72	(20%)
Reference prices								
Dated Brent (US $/bbl)	61.92	53.97	109.63	15%	(44%)	57.95	108.93	(47%)
Dated Brent ($/bbl)	76.12	66.98	119.55	14%	(36%)	71.59	119.50	(40%)

Sales

- Crude oil production in France is priced with reference to Dated Brent.
- Sales per boe increased by 12% quarter-over-quarter, consistent with a 14% increase in the Canadian dollar equivalent of the Dated Brent reference price. This increase, coupled with a smaller inventory build in the quarter, resulted in a 36% increase in sales.
- On a year-over-year basis, sales per boe decreased by 39% and 42% for the three and six months ended June 30, 2015, respectively. In both periods, this was consistent with a decrease in the Dated Brent reference price, and was partially offset by increases in production. This resulted in a decrease in sales for both the three and six month periods ended June 30, 2015 of 34% and 42%, respectively.

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).
- Royalties as a percentage of sales was 8.1% and 8.3% for the three and six months ended June 30, 2015, relatively consistent with 8.5% in Q1 2015, and an increase over both comparable periods in 2014. The year-over-year increase was due to the impact of fixed RCDM royalties coupled with lower realized pricing.

Transportation

- Transportation expense increased slightly for Q2 2015 as compared to Q1 2015 due to a higher number of shipments from the Ambès terminal during the current quarter.
- Transportation expense decreased for both the three and six months ended June 30, 2015 as compared to the same periods in 2014 due to a lower level of maintenance and project activity at the Ambès terminal coupled with cost savings associated with fewer shipments at the terminal due to the usage of larger shipping vessels.

Operating expense

- On a dollar basis, Q2 2015 operating expense was higher than Q1 2015 due to increased electricity costs and a higher level of well intervention activities.
- Operating expense on a dollar and per boe basis decreased for the three and six months ended June 30, 2015 versus the same periods in 2014 due to a number of cost reduction initiatives undertaken in response to commodity price weakness. These cost reduction initiatives included lower costs on downhole and other activities, lower labour usage and costs, as well as savings from service contract renegotiations.
- In addition, on a year-over-year basis, operating expenses further decreased due to the favorable foreign exchange impact of the strengthening of the Canadian dollar versus the Euro and the deferral of costs following a build in crude oil inventory in the 2015 periods.

General and administration

- Fluctuations in general and administration expense for the three and six months ended June 30, 2015 versus all comparable periods was primarily the result of the favorable foreign exchange impact of a stronger Canadian dollar versus the Euro.

Other income

- In the six months ended June 30, 2015, Vermilion was awarded a judgment pertaining to costs incurred as a result of an oil spill at the Ambès oil terminal in France that occurred in 2007. As a result of the award, $31.8 million (before taxes) was recognized as other income.

Current income taxes

- Current income taxes in France are applied to taxable income, after eligible deductions, at a statutory rate of 34.4% for 2015. In addition, a 10.7% temporary surtax (as a percentage of the statutory rate) is applicable for tax year 2015 if annual revenue exceeds €250 million. For 2015, the effective rate on current income taxes is expected to be between approximately 17% and 19%. This rate is subject to change in response to commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Absent of the taxes recognized in Q1 2015 for the previously mentioned recovery of costs in France, Q2 2015 current income taxes increased compared to Q1 2015 due to increased revenues.
- Current income taxes for the three and six months ended June 30, 2015 decreased versus the comparative periods in 2014. The decrease was the result of lower funds from operations as a result of the decline in the 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 800,000 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		Six Months Ended		% change
Netherlands business unit	Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Jun 30, 2015	Jun 30, 2014	2015 vs. 2014
Production								
NGLs (bbls/d)	112	63	96	78%	17%	88	83	6%
Natural gas (mmcf/d)	32.43	36.41	40.35	(11%)	(20%)	34.41	41.74	(18%)
Total (boe/d)	5,517	6,132	6,822	(10%)	(19%)	5,823	7,040	(17%)
Activity								
Capital expenditures ($M)	18,885	4,333	21,513	336%	(12%)	23,218	41,631	(44%)
Gross wells drilled	2.00	-	2.00			2.00	4.00	
Net wells drilled	1.86	-	1.43			1.86	3.29	

Production

- Production decreased 10% quarter-over-quarter due to a planned major facility maintenance at our Garijp Treatment Centre which negatively impacted Q2 production by approximately 2,400 mcf/d (400 boe/d).
- Year-over-year and year-to-date production decreased 19% and 17% respectively due to loss of production from our Middenmeer-3 well, which was fully depleted and taken offline in February 2015. The depletion of this well occurred as expected. The turnaround at the Garijp Treatment Centre during Q2 2015 contributed to the decrease in production.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

Activity review

- During Q2, Vermilion drilled two (1.9 net) wells, Slootdorp-06 and Slootdorp-07. These wells are currently on sales during an extended production test to size additional production equipment. The wells are producing at facility-restricted rates totaling 21 mmcf/d (3,500 boe/d) net.
- Capital previously allocated to a planned third well has been redeployed to support a highly economic debottlenecking project at our Garijp Treatment Centre and associated gathering system.
- During the second half of 2015, we expect to equip and tie-in the Diever-02 discovery well drilled in 2014.

Financial review

Netherlands business unit ($M except as indicated)	Three Months Ended Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	% change Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Six Months Ended Jun 30, 2015	Jun 30, 2014	% change 2015 vs. 2014
Sales	23,913	26,818	29,881	(11%)	(20%)	50,731	71,435	(29%)
Royalties	(1,294)	(926)	(693)	40%	87%	(2,220)	(2,901)	(23%)
Operating expense	(5,414)	(5,826)	(6,390)	(7%)	(15%)	(11,240)	(12,432)	(10%)
General and administration	(454)	(737)	(326)	(38%)	39%	(1,191)	(924)	29%
Current income taxes	(2,347)	(2,388)	(1,301)	(2%)	80%	(4,735)	(5,089)	(7%)
Fund flows from operations	14,404	16,941	21,171	(15%)	(32%)	31,345	50,089	(37%)
Netbacks ($/boe)								
Sales	47.63	48.60	48.14	(2%)	(1%)	48.13	56.06	(14%)
Royalties	(2.58)	(1.68)	(1.12)	54%	130%	(2.11)	(2.28)	(7%)
Operating expense	(10.78)	(10.56)	(10.29)	2%	5%	(10.66)	(9.76)	9%
General and administration	(0.90)	(1.34)	(0.53)	(33%)	70%	(1.13)	(0.73)	55%
Current income taxes	(4.67)	(4.33)	(2.10)	8%	122%	(4.49)	(3.99)	13%
Fund flows from operations netback	28.70	30.69	34.10	(6%)	(16%)	29.74	39.30	(24%)
Reference prices								
TTF ($/GJ)	7.94	8.25	7.91	(4%)	-	8.10	9.02	(10%)
TTF (€/GJ)	5.84	5.91	5.27	(1%)	11%	5.87	6.01	(2%)

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.
- Sales per boe decreased by 2% quarter-over-quarter, consistent with a 4% decrease in the Canadian dollar equivalent TTF reference price. This was coupled with a 10% decrease in production, resulting in an 11% decrease in sales.
- On a year-over-year basis, sales per boe declined by 1% and 14% for the three and six months ended June 30, 2015, respectively. For the three months ended June 30, 2015, the 20% decrease in sales was entirely attributable to the decrease in production. For the six months ended June 30, 2015, a decrease in sales per boe of 14% was consistent with a 10% decrease in the Canadian dollar equivalent of TTF, and, combined with a 17% decrease in production, resulted in a 29% decrease in sales.

Royalties

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

Transportation expense

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

Operating expense

- Operating expense on a dollar basis decreased for the three and six months ended June 30, 2015 versus all comparable periods primarily as a result of a stronger Canadian dollar versus the Euro coupled with lower facility operations expenditures due to cost reduction initiatives undertaken in response to commodity price weakness.
- However, as production in the Netherlands was lower in the current year, operating expense per boe for the three and six months ended June 30, 2015 was higher versus all comparable periods.

General and administration

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

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 2015, the effective rate on current taxes is expected to be between approximately 12% and 14%. This rate is subject to change in response to commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Current income taxes in Q2 2015 were comparable to Q1 2015.
- Current income taxes in Q2 2015 were higher than Q2 2014 as higher revenues were offset with accelerated tax deductions in the current quarter.

GERMANY BUSINESS UNIT

Overview

- Vermilion entered Germany in February 2014.
- Assets include four gas producing fields across 11 production licenses and an exploration license in surrounding fields. Our working interest is 25%.
- Total license area comprises 204,000 gross acres, of which 85% is in the exploration license.

Operational review

Germany business unit	Three Months Ended Jun 30, 2015	Three Months Ended Mar 31, 2015	Three Months Ended Jun 30, 2014	% change Q2/15 vs. Q1/15	% change Q2/15 vs. Q2/14	Six Months Ended Jun 30, 2015	Six Months Ended Jun 30, 2014	% change 2015 vs. 2014
Production								
Natural gas (mmcf/d)	16.18	16.80	16.13	(4%)	-	16.49	13.40	23%
Total (boe/d)	2,696	2,801	2,689	(4%)	-	2,748	2,234	23%
Activity								
Capital expenditures ($M)	3,231	968	630	234%	413%	4,199	826	408%
Acquisitions ($M)	-	-	-			-	172,871	
Gross wells drilled	1.00	-	-			1.00	-	
Net wells drilled	0.25	-	-			0.25	-	

Production

- Q2 2015 production of 2,696 boe/d represented a decrease of 4% as compared to the prior quarter while year-over-year production was flat. Year-to-date production increased 23% versus prior year, due to 2014 volumes only reflecting production from the acquisition's effective date of February 1, 2014.

Activity review

- Participated in the drilling of the Burgmoor Z3a sidetrack well (25% working interest), which was completed in Q2 2015. Subsequent to the quarter, the well was tied-in and placed on production.

Financial review

	Three Months Ended			% change		Six Months Ended		% change
Germany business unit ($M except as indicated)	Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Jun 30, 2015	Jun 30, 2014	2015 vs. 2014
Sales	10,626	11,395	11,097	(7%)	(4%)	22,021	20,012	10%
Royalties	(2,238)	(1,598)	(2,284)	40%	(2%)	(3,836)	(4,086)	(6%)
Transportation expense	(1,240)	(894)	(1,052)	39%	18%	(2,134)	(1,474)	45%
Operating expense	(1,373)	(1,999)	(2,043)	(31%)	(33%)	(3,372)	(3,597)	(6%)
General and administration	(1,435)	(1,608)	(830)	(11%)	73%	(3,043)	(1,398)	118%
Current income taxes	-	-	(506)	-	(100%)	-	(1,043)	(100%)
Fund flows from operations	4,340	5,296	4,382	(18%)	(1%)	9,636	8,414	15%
Netbacks ($/boe)								
Sales	43.31	45.21	45.36	(4%)	(5%)	44.27	49.50	(11%)
Royalties	(9.12)	(6.34)	(9.34)	44%	(2%)	(7.71)	(10.11)	(24%)
Transportation expense	(5.05)	(3.55)	(4.30)	42%	17%	(4.29)	(3.65)	18%
Operating expense	(5.60)	(7.93)	(8.35)	(29%)	(33%)	(6.78)	(8.90)	(24%)
General and administration	(5.85)	(6.38)	(3.39)	(8%)	73%	(6.12)	(3.46)	77%
Current income taxes	-	-	(2.07)	-	(100%)	-	(2.58)	(100%)
Fund flows from operations netback	17.69	21.01	17.91	(16%)	(1%)	19.37	20.80	(7%)
Reference prices								
TTF ($/GJ)	7.94	8.25	7.91	(4%)	-	8.10	9.02	(10%)
TTF (€/GJ)	5.84	5.91	5.27	(1%)	11%	5.87	6.01	(2%)

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.
- The 7% decrease in sales quarter-over-quarter is due to a 4% decrease in sales per boe, consistent with the decrease in the Canadian dollar equivalent of the TTF reference price, and a 4% decrease in production.
- On a year-over-year basis, sales per boe declined by 5% and 11% for the three and six months ended June 30, 2015, respectively. For the three months ended June 30, 2015, production remained relatively consistent, resulting in a 4% decrease in sales. For the six months ended June 30, 2015, production increased by 23% but was partially offset by a stronger CAD versus the Euro, resulting in a 10% increase in sales.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions. As a percentage of sales, royalties are expected to range from 15% to 20% in 2015.
- Q2 2015 royalties as a percentage of sales of 21.1% were higher than the 14.0% for Q1 2015 due to adjustments for prior period royalties. Year-to-date royalties as a percentage of sales of 17.4% were lower than the 20.4% for the comparable period in 2014 as a result of lower state royalty rates for 2015.

Transportation expense

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer.
- Q2 2015 transportation expense was higher than Q1 2015 and Q2 2014 due to final adjustments recorded for 2014 during the current quarter. Year-to-date transportation expense was higher than the comparable period in 2014 due to the aforementioned adjustments and the inclusion of only 5 months of expense in 2014 due to the timing of our Germany acquisition.

Operating expense

- Operating expenses for Germany are billed monthly by the joint venture operator and primarily relate to tariffs charged for gas processing.
- Q2 2015 had lower operating expenses on a dollar and per boe basis versus both Q1 2015 and Q2 2014 due to lower levels of project activity during the current quarter.
- Operating expense for the six months ended June 30, 2015 decreased on a dollar and per boe basis versus the same period in 2014 due to the timing of the acquisition and reduced gas processing tariffs in 2015.

General and administration

- General and administration expense decreased quarter-over-quarter as a result of the timing of allocations from Vermilion's Corporate segment.

Current income taxes

- Current income taxes in Germany apply to taxable income after eligible deductions at a statutory tax rate of approximately 24%. As a function of Germany's tax pools, Vermilion does not presently pay taxes in Germany.

IRELAND BUSINESS UNIT

Overview

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

Operational and financial review

	Three Months Ended			% change		Six Months Ended		% change
Ireland business unit ($M)	Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Jun 30, 2015	Jun 30, 2014	2015 vs. 2014
Transportation expense	(1,648)	(1,693)	(1,571)	(3%)	5%	(3,341)	(3,159)	6%
General and administration	(628)	(512)	(252)	23%	149%	(1,140)	(534)	113%
Fund flows from operations	(2,276)	(2,205)	(1,823)	3%	25%	(4,481)	(3,693)	21%
Activity								
Capital expenditures	20,267	12,955	27,221	56%	(26%)	33,222	43,457	(24%)

Activity review

- Following minor remaining compressor maintenance, operator Shell E&P Ireland Limited expects to declare all wells, facilities and transport systems ready for service by the end of August. Prior to commencing gas production, the Irish Environmental Protection Agency ("EPA") must issue its Final Determination for the Corrib Industrial Emissions Licence ("IEL") and Ministerial Consent is required from the Department of Communications, Environment, and Natural Resources. The EPA issued its Proposed Determination for the Corrib IEL in April 2015, and following statutory consultation and review periods is expected to issue its Final Determination on the IEL on or before mid-September. We now estimate that the Ministerial Consent process will be completed, and that production will commence, in early-to-mid fourth quarter of 2015.
- Capital expenditures at Corrib total $33 million year-to-date in 2015. We currently expect to incur an additional $30 to $35 million of capital expenditures at Corrib prior to achieving first gas in early to mid-Q4 2015.
- Production at Corrib is expected to increase over the first few months toward peak production levels estimated at approximately 58 mmcf/d (approximately 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 a 100% operated working interest in the Wandoo field, located approximately 80 km offshore on the northwest shelf of Australia.
- Production is operated from two off-shore platforms, and originates from 21 producing well bores.
- Wells that utilize horizontal legs (ranging in length from 500 to 3,000 plus metres) are located 600 metres below the seabed in approximately 55 metres of water depth.
- Contracted crude oil production is priced with reference to Dated Brent.

Operational review

	Three Months Ended			% change		Six Months Ended		% change
Australia business unit	Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Jun 30, 2015	Jun 30, 2014	2015 vs. 2014
Production								
Crude oil (bbls/d)	5,865	5,672	6,483	3%	(10%)	5,769	6,795	(15%)
Inventory (mbbls)								
Opening crude oil inventory	318	37	63			37	130	
Crude oil production	534	511	590			1,044	1,230	
Crude oil sales	(696)	(230)	(464)			(925)	(1,171)	
Closing crude oil inventory	156	318	189			156	189	
Activity								
Capital expenditures ($M)	6,468	6,455	10,991	-	(41%)	12,923	16,682	(23%)

Production

- Quarterly production increased 3% quarter-over-quarter and decreased 10% year-over-year. Production volumes are managed within corporate targets while meeting customer demands and the requirements of long-term supply agreements.
- We continue to plan for long-term production levels of between 6,000 and 8,000 bbls/d.

Activity review

- In Q2 2015, efforts were largely focused on maintenance work, facilities enhancement and preparations for 2015 and 2016 drilling programs.
- We have reinstated the previously-deferred two-well sidetrack drilling program for 2015.
- Additional 2015 planned activities include ongoing facilities maintenance, enhancement, and refurbishment, as well as preparation and permitting activities in advance of our 2016 drilling program.

Financial review

Australia business unit ($M except as indicated)	Three Months Ended Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	% change Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	Six Months Ended Jun 30, 2015	Jun 30, 2014	% change 2015 vs. 2014
Sales	56,204	19,284	58,828	191%	(4%)	75,488	148,802	(49%)
Operating expense	(18,083)	(5,886)	(12,051)	207%	50%	(23,969)	(29,411)	(19%)
General and administration	(1,141)	(1,454)	(1,661)	(22%)	(31%)	(2,595)	(2,867)	(9%)
PRRT	(3,371)	(2,354)	(12,699)	43%	(73%)	(5,725)	(32,938)	(83%)
Corporate income taxes	(5,134)	(577)	(5,689)	790%	(10%)	(5,711)	(14,530)	(61%)
Fund flows from operations	28,475	9,013	26,728	216%	7%	37,488	69,056	(46%)
Netbacks ($/boe)								
Sales	80.87	83.80	126.87	(3%)	(36%)	81.60	127.11	(36%)
Operating expense	(26.02)	(25.58)	(25.99)	2%	-	(25.91)	(25.12)	3%
General and administration	(1.64)	(6.32)	(3.58)	(74%)	(54%)	(2.81)	(2.45)	15%
PRRT	(4.85)	(10.23)	(27.39)	(53%)	(82%)	(6.19)	(28.14)	(78%)
Corporate income taxes	(7.39)	(2.51)	(12.27)	194%	(40%)	(6.17)	(12.41)	(50%)
Fund flows from operations netback	40.97	39.16	57.64	5%	(29%)	40.52	58.99	(31%)
Reference prices								
Dated Brent (US $/bbl)	61.92	53.97	109.63	15%	(44%)	57.95	108.93	(47%)
Dated Brent ($/bbl)	76.12	66.98	119.55	14%	(36%)	71.59	119.50	(40%)

Sales

- Our production in Australia currently receives a premium to Dated Brent.
- During Q2 2015, inventory decreased by 162,000 bbls versus builds of 281,000 bbls and 126,000 bbls in Q1 2015 and Q2 2014, respectively. For the six months ended June 30, 2015, inventory increased by 119,000 bbls, as compared to a build of 59,000 bbls in the comparable period in 2014.
- Sales per boe decreased 3% in Q2 2015 versus Q1 2015 despite an increase of 14% in the Canadian dollar equivalent of the Dated Brent reference price due to the timing of sales. This was more than offset by a significant increase in sales volumes driven by the draw in inventory, resulting in a 191% increase in sales.
- On a year-over-year basis, sales per boe decreased by 36% for both the three and six months ended June 30, 2015, consistent with a decrease in the Dated Brent reference price. For the three months ended June 30, 2015, this was almost entirely offset by a significant increase in sales volumes driven by a draw in inventory, resulting in a 4% decrease in sales. For the six months ended June 30, 2015, a greater build in inventory led to a 49% decrease in sales.

Royalties and transportation expense

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

Operating expense

- The increase in operating expense for Q2 2015 as compared to Q1 2015 and Q2 2014 was largely the result of a drawdown of inventory during the quarter versus a build in the comparable periods. Operating expense per boe for Q2 2015 versus both Q1 2015 and Q2 2014 was largely unchanged.
- The decrease in operating expense for the year-to-date 2015 period versus 2014 was largely the result of savings from a wide range of cost reduction initiatives undertaken in response to commodity price weakness including reduced vessel usage, lower diesel consumption, and reduced staffing costs. On a per boe basis, these cost reductions were offset by lower production volumes causing increased per barrel costs.

General and administration

- Fluctuations in general and administration expense for the three and six months versus the comparable periods was largely a result of the timing of expenditures.

PRRT and corporate income taxes

- In Australia, current income taxes include both PRRT and corporate income taxes. PRRT is a profit based tax applied at a rate of 40% on sales less eligible expenditures, including operating expenses and capital expenditures. Corporate income taxes are applied at a rate of 30% on taxable income after eligible deductions, which include PRRT.
- For 2015, the combined corporate income tax and PRRT effective rate is expected to be between approximately 22% and 24%. 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 for the six months ended June 30, 2015 was lower than the comparable period in 2014. The decrease was due to a more significant decrease in revenues in the current year as compared to capital spending.

UNITED STATES BUSINESS UNIT

Overview

- Entered the United States in September 2014.
- Interests include approximately 68,000 acres of land (98% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Promising tight oil development targeting the Turner Sand at a depth of approximately 1,500 metres.

Operational and financial review

United States business unit ($M except as indicated)	Three Months Ended Jun 30, 2015	Three Months Ended Mar 31, 2015	% change Q2/15 vs. Q1/15
Sales	677	672	1%
Royalties	(191)	(206)	(7%)
Operating expense	(110)	(215)	(49%)
General and administration	(963)	(1,080)	(11%)
Fund flows from operations	(587)	(829)	(29%)
Netbacks ($/boe)			
Sales	60.57	48.79	24%
Royalties	(17.08)	(14.98)	14%
Operating expense	(9.88)	(15.61)	(37%)
General and administration	(86.12)	(78.41)	10%
Fund flows from operations netback	(52.51)	(60.21)	(13%)
Reference prices			
WTI (US $/bbl)	57.94	48.63	19%
WTI ($/bbl)	71.23	60.35	18%
Production			
Crude oil (bbls/d)	123	153	(20%)
Activity			
Capital expenditures	2,744	637	331%
Gross wells drilled	1.00	-	
Net wells drilled	1.00	-	

Activity review

- Vermilion drilled the Seedy Draw North well (100% working interest) in the East Finn prospect area in Q2 2015, with completion of the well planned in Q3 2015.

Sales

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

Royalties

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax at a combined rate of approximately 27.5% of sales.

Operating expense

- Operating expense was lower than the previous quarter due to lower fuel and salt water disposal costs.

General and administration

- General and administration expense was consistent with the prior quarter.

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

($M)	Three Months Ended Jun 30, 2015	Three Months Ended Mar 31, 2015	Three Months Ended Jun 30, 2014	Six Months Ended Jun 30, 2015	Six Months Ended Jun 30, 2014
General and administration	500	957	(2,574)	1,457	(6,325)
Current income taxes	(547)	(377)	(378)	(924)	(551)
Interest expense	(14,550)	(13,298)	(12,334)	(27,848)	(23,794)
Realized gain on derivatives	3,081	6,257	2,419	9,338	5,059
Realized foreign exchange (loss) gain	(2,740)	3,306	587	566	(1,454)
Realized other income	204	222	74	426	295
Fund flows from operations	(14,052)	(2,933)	(12,206)	(16,985)	(26,770)

General and administration

- The decrease in general and administration costs for the three and six months ended June 30, 2015 versus the comparable periods in 2014 is due to a decrease in staff-related expenditures, general cost saving initiatives in response to declining crude prices, and increased salary allocations to the various segments.

Current income taxes

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

Interest expense

- Interest expense increased in Q2 2015 versus Q1 2015 and Q2 2014 primarily due to the recognition of a full quarter of interest expense related to the finance lease recognized in Q1 2015. For the six months ended June 30, 2015, the increase versus the comparable period in 2014 is due to increased borrowings under our revolving credit facility, as well as the aforementioned interest on the finance lease.

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) 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 Q2 2015 related primarily to amounts received on our Dated Brent, WTI, and AECO derivatives, partially offset by payments made on our foreign exchange derivatives.
- A listing of derivative positions as at June 30, 2015 is included in "Supplemental Table 2" in this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Three Months Ended							
($M except per share)	Jun 30, 2015	Mar 31, 2015	Dec 31, 2014	Sep 30, 2014	Jun 30, 2014	Mar 31, 2014	Dec 31, 2013	Sep 30, 2013
Petroleum and natural gas sales	264,331	195,885	306,073	344,688	387,684	381,183	325,108	327,185
Net earnings	6,813	1,275	58,642	53,903	53,993	102,788	101,510	67,796
Net earnings per share								
Basic	0.06	0.01	0.55	0.50	0.51	1.00	1.00	0.67
Diluted	0.06	0.01	0.54	0.50	0.50	0.99	0.98	0.66

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

($M)	Q2/15 vs. Q1/15	Q2/15 vs. Q2/14	2015 vs. 2014
Net earnings - Comparative period	1,275	53,993	156,781
Changes in:			
Fund flows from operations	8,701	(86,580)	(171,148)
Equity based compensation	1,154	331	(2,237)
Unrealized gain or loss on derivative instruments	24,075	5,626	(18,279)
Unrealized foreign exchange gain or loss	9,876	28,777	1,932
Unrealized other expense	57	(308)	(315)
Accretion	(38)	237	274
Depletion and depreciation	(20,189)	(6,244)	2,251
Deferred tax	(18,098)	10,981	38,829
Net earnings - Current period	6,813	6,813	8,088

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

Equity based compensation expense in Q2 2015 was lower than Q1 2015 as a result of awards that vested during Q2 2015 with higher actual performance conditions. For the six months ended June 30, 2015, equity based compensation expense was higher versus the comparable period due to a higher number of awards outstanding.

Unrealized gain or loss on derivative instruments

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

For the six months ended June 30, 2015, we recognized an unrealized loss on derivative instruments of $15.9 million, relating primarily to our TTF, Dated Brent, and WTI swaps and collars. As at June 30, 2015, we have a net derivative asset position of $8.9 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 months ended June 30, 2015, the Canadian dollar weakened versus the Euro and the US dollar, resulting in an unrealized foreign exchange gain of $5.0 million. For the six months ended June 30, 2015, the foreign exchange gain of $0.2 million was driven by a significant weakening of the Canadian dollar against the US dollar, offset by a slight strengthening of the Canadian dollar relative to the Euro.

Accretion

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

Q2 2015 accretion expense was relatively consistent with all comparative periods.

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 Q2 2015 of $22.98 was slightly higher as compared to $21.90 and $22.45 in Q1 2015 and Q2 2014, respectively. The increase is due to increased production from light crude oil properties in Saskatchewan, Canada which has higher per boe depletion expense, and decreased production from natural gas properties in Drayton Valley, Canada and in the Netherlands, which have lower per boe depletion expense. On a year-over-year basis, depletion and depreciation on a per boe decreased to $22.48 per boe for the six months ended June 30, 2015, as compared to $22.78 in the comparable period in the prior year. This decrease is primarily due to lower production in the Cardium light crude oil resource play in Canada and in Australia, which experience higher per boe amounts.

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

In the current low commodity price environment, Vermilion's net debt to fund flows ratio is expected to be higher than the longer term target ratio. During this period, Vermilion will remain focused on maintaining a strong balance sheet and will manage its business accordingly.

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)	Jun 30, 2015	Dec 31, 2014	Jun 30, 2015	Dec 31, 2014
Revolving credit facility	3.0%	3.1%	1,200,077	1,014,067
Senior unsecured notes (1)	6.5%	6.5%	224,457	224,013
Long-term debt	3.6%	3.8%	1,424,534	1,238,080

(1) The senior unsecured notes, which will mature on February 10, 2016, are included in the current portion of long-term debt as at June 30, 2015.

Revolving Credit Facility

On January 30, 2015, Vermilion increased its credit facility from $1.5 billion to $1.75 billion. During Q2 2015, we negotiated a further expansion and extension of our existing revolving credit facilities from $1.75 billion to $2 billion with a maturity of May 2019. The 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	
	Jun 30, 2015	Dec 31, 2014
Total facility amount	$2.0 billion	$1.5 billion
Amount drawn	$1.2 billion	$1.0 billion
Letters of credit outstanding	$26.5 million	$8.6 million
Facility maturity date	31-May-19	31-May-17

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

		As at	
Financial covenant	Limit	Jun 30, 2015	Dec 31, 2014
Consolidated total debt to consolidated EBITDA	4.0	1.84	1.21
Consolidated total senior debt to consolidated EBITDA	3.0	1.52	0.99
Consolidated total senior debt to total capitalization	50%	35%	31%

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", "Current portion of long-term debt", and "Finance lease obligation" on our balance sheet.
- Consolidated total senior debt: Defined as consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Defined as consolidated net earnings before interest, income taxes, depreciation, accretion and certain other non-cash items.
- Total capitalization: Includes all amounts on our balance sheet classified as "Long-term debt", "Current portion of long-term debt", "Finance lease obligation", 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

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)	Jun 30, 2015	Dec 31, 2014
Long-term debt	1,200,077	1,238,080
Current liabilities[1]	479,848	365,729
Current assets	(302,023)	(338,159)
Net debt	1,377,902	1,265,650
Ratio of net debt to annualized fund flows from operations	2.8	1.6

[1] Includes the current portion of long-term debt, which, as at June 30, 2015, represents the senior unsecured notes that will mature on February 10, 2016.

Long term debt, including the current portion, as at June 30, 2015 increased to $1.42 billion from $1.24 billion as at December 31, 2014 as a result of draws on the revolving credit facility during the current year to fund capital expenditures, particularly relating to development expenditures in Canada and Ireland. The increase in long-term debt resulted in an increase to net debt from $1.27 billion to $1.38 billion. As a result of this increase to long-term debt and weak commodity prices, the ratio of net debt to fund flows from operations increased from 1.6 times as at December 31, 2014 to 2.8 times for the six months ended June 30, 2015.

Shareholders' capital

During the six months ended June 30, 2015, we maintained monthly dividends at $0.215 per share and declared dividends which totalled $140.4 million.

The following table outlines our dividend payment history:

Date	Monthly dividend per unit or share
January 2003 to December 2007	$0.170
January 2008 to December 2012	$0.190
January 2013 to December 31, 2013	$0.200
January 2014 to Present	$0.215

Our policy with respect to dividends is to be conservative and maintain a low ratio of dividends to fund flows from operations. During low commodity price cycles, we will initially maintain dividends and allow the ratio to rise. Should low commodity price cycles remain for an extended period of time, we will evaluate the necessity of changing the level of dividends, taking into consideration capital development requirements, debt levels and acquisition opportunities. In a further step to preserve our financial flexibility and conservatively exercise our access to capital, an amendment to our existing DRIP to include a Premium Dividend™ Component was announced in February 2015. The Premium Dividend™ Component, when combined with our continuing Dividend Reinvestment Component, increases our access to the lowest cost sources of equity capital available. While the Premium Dividend™ results in a modest amount of equity issuance, we believe it represents the most prudent approach to preserving near-term balance sheet strength. We view implementation of a Premium Dividend™ as a short-term measure to maintain our financial flexibility while we continue to lower our unit costs and await further clarity on the direction of commodity prices. Both components of our program can be turned off at the company's discretion, offering considerable flexibility. We will actively monitor our ongoing needs and manage our continued use of each component as circumstances dictate. It is not currently expected that Vermilion will be required to change its dividend in 2015.

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, 2014	107,303	1,959,021
Issuance of shares pursuant to the dividend reinvestment and Premium Dividend™ plans	1,195	63,679
Vesting of equity based awards	1,158	56,855
Share-settled dividends on vested equity based awards	135	7,561
Shares issued pursuant to the employee savings and bonus plans	15	816
Balance as at June 30, 2015	109,806	2,087,932

As at June 30, 2015, there were approximately 1.7 million VIP awards outstanding. As at August 6, 2015, there were approximately 110.1 million common shares issued and outstanding.

ASSET RETIREMENT OBLIGATIONS

As at June 30, 2015, asset retirement obligations were $351.3 million compared to $350.8 million as at December 31, 2014.

The slight increase in asset retirement obligations is largely attributable to accretion and additions from new wells drilled year-to-date, offset by an overall increase in the discount rates applied to the abandonment obligations.

OFF BALANCE SHEET ARRANGEMENTS

We have certain lease agreements that are entered into in the normal course of operations, including operating leases for which no asset or liability value has been assigned to the consolidated balance sheet as at June 30, 2015.

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

RISK MANAGEMENT

Vermilion is exposed to various market and operational risks. For a detailed discussion of these risks, please see Vermilion's Annual Report for the year ended December 31, 2014.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of any possible contingencies. These estimates and assumptions are developed based on the best available information which management believed to be reasonable at the time such estimates and assumptions were made. As such, these assumptions are uncertain at the time estimates are made and could change, resulting in a material impact on Vermilion's consolidated financial statements. Estimates are reviewed by management on an ongoing basis and as a result may change from period to period due to the availability of new information or changes in circumstances. Additionally, as a result of the unique circumstances of each jurisdiction that Vermilion operates in, the critical accounting estimates may affect one or more jurisdictions. There have been no material changes to our critical accounting estimates used in applying accounting policies for the six months ended June 30, 2015. Further information, including a discussion of critical accounting estimates, can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2014, available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Supplemental Table 1: Netbacks

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

	Three Months Ended June 30, 2015			Six Months Ended June 30, 2015			Three Months Ended June 30, 2014	Six Months Ended June 30, 2014
	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	59.06	2.78	40.59	54.14	2.88	38.24	71.56	70.55
Royalties	(5.31)	0.17	(2.56)	(5.59)	(0.03)	(3.25)	(7.99)	(7.61)
Transportation	(2.67)	(0.18)	(1.99)	(2.55)	(0.17)	(1.90)	(1.76)	(1.75)
Operating	(10.53)	(1.39)	(9.58)	(9.78)	(1.40)	(9.19)	(9.28)	(9.31)
Operating netback	40.55	1.38	26.46	36.22	1.28	23.90	52.53	51.88
General and administration			(2.45)			(2.15)	(2.88)	(2.32)
Fund flows from operations netback			24.01			21.75	49.65	49.56
France								
Sales	72.83	1.53	71.96	68.97	1.53	68.52	117.29	117.41
Royalties	(5.92)	(0.01)	(5.84)	(5.72)	(0.01)	(5.68)	(7.34)	(7.34)
Transportation	(3.15)	-	(3.11)	(3.19)	-	(3.17)	(5.07)	(4.91)
Operating	(10.72)	(1.16)	(10.67)	(11.14)	(1.16)	(11.11)	(15.58)	(15.98)
Operating netback	53.04	0.36	52.34	48.92	0.36	48.56	89.30	89.18
General and administration			(4.30)			(4.84)	(5.24)	(5.21)
Other income			-			15.39	-	-
Current income taxes			(8.21)			(11.43)	(23.30)	(24.25)
Fund flows from operations netback			39.83			47.68	60.76	59.72
Netherlands								
Sales	53.28	7.92	47.63	53.15	8.01	48.13	48.14	56.06
Royalties	-	(0.44)	(2.58)	-	(0.36)	(2.11)	(1.12)	(2.28)
Operating	-	(1.83)	(10.78)	-	(1.80)	(10.66)	(10.29)	(9.76)
Operating netback	53.28	5.65	34.27	53.15	5.85	35.36	36.73	44.02
General and administration			(0.90)			(1.13)	(0.53)	(0.73)
Current income taxes			(4.67)			(4.49)	(2.10)	(3.99)
Fund flows from operations netback			28.70			29.74	34.10	39.30
Germany								
Sales	-	7.22	43.31	-	7.38	44.27	45.36	49.50
Royalties	-	(1.52)	(9.12)	-	(1.29)	(7.71)	(9.34)	(10.11)
Transportation	-	(0.84)	(5.05)	-	(0.72)	(4.29)	(4.30)	(3.65)
Operating	-	(0.93)	(5.60)	-	(1.13)	(6.78)	(8.35)	(8.90)
Operating netback	-	3.93	23.54	-	4.24	25.49	23.37	26.84
General and administration			(5.85)			(6.12)	(3.39)	(3.46)
Current income taxes			-			-	(2.07)	(2.58)
Fund flows from operations netback			17.69			19.37	17.91	20.80
Australia								
Sales	80.87	-	80.87	81.60	-	81.60	126.87	127.11
Operating	(26.02)	-	(26.02)	(25.91)	-	(25.91)	(25.99)	(25.12)
PRRT (1)	(4.85)	-	(4.85)	(6.19)	-	(6.19)	(27.39)	(28.14)
Operating netback	50.00	-	50.00	49.50	-	49.50	73.49	73.85
General and administration			(1.64)			(2.81)	(3.58)	(2.45)
Corporate income taxes			(7.39)			(6.17)	(12.27)	(12.41)
Fund flows from operations netback			40.97			40.52	57.64	58.99
United States								
Sales	60.57	-	60.57	54.07	-	54.07	-	-
Royalties	(17.08)	-	(17.08)	(15.92)	-	(15.92)	-	-
Operating	(9.88)	-	(9.88)	(13.04)	-	(13.04)	-	-
Operating netback	33.61	-	33.61	25.11	-	25.11	-	-
General and administration			(86.12)			(81.87)	-	-
Fund flows from operations netback			(52.51)			(56.76)	-	-

	Three Months Ended June 30, 2015			Six Months Ended June 30, 2015			Three Months Ended June 30, 2014	Six Months Ended June 30, 2014
	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Total Company								
Sales	68.90	4.86	54.65	64.23	5.06	51.19	82.96	85.70
Realized hedging (loss) gain	(0.13)	0.33	0.64	0.26	0.38	1.04	0.52	0.56
Royalties	(4.37)	(0.25)	(3.33)	(4.73)	(0.31)	(3.62)	(6.21)	(5.91)
Transportation	(2.23)	(0.38)	(2.25)	(2.34)	(0.36)	(2.27)	(2.57)	(2.44)
Operating	(14.03)	(1.45)	(12.12)	(12.97)	(1.48)	(11.40)	(12.46)	(12.95)
PRRT [1]	(1.09)	-	(0.70)	(1.03)	-	(0.64)	(2.72)	(3.67)
Operating netback	47.05	3.11	36.89	43.42	3.29	34.30	59.52	61.29
General and administration			(3.00)			(3.12)	(3.80)	(3.59)
Interest expense			(3.01)			(3.10)	(2.64)	(2.65)
Realized foreign exchange (loss) gain			(0.57)			0.06	0.12	(0.16)
Other income			0.04			3.58	0.02	0.03
Corporate income taxes [1]			(3.59)			(3.89)	(6.98)	(7.94)
Fund flows from operations netback			26.76			27.83	46.24	46.98

(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 June 30, 2015:

	Note	Volume	Strike Price(s)
Crude Oil			
WTI - Collar			
July 2015 - September 2015	1	250 bbl/d	60.00 - 68.60 US $
July 2015 - October 2015	1	250 bbl/d	60.00 - 72.40 US $
July 2015 - December 2015	2	750 bbl/d	75.00 - 82.60 CAD $
July 2015 - December 2015	1	250 bbl/d	61.00 - 69.75 US $
July 2015 - March 2016	3	250 bbl/d	75.00 - 83.45 CAD $
July 2015 - June 2016	4	500 bbl/d	75.50 - 85.08 CAD $
October 2015 - December 2015	3	250 bbl/d	70.00 - 82.95 CAD $
WTI - Swap			
July 2015 - September 2015	5	250 bbl/d	75.71 CAD $
MSW - Fixed Price Differential			
July 2015 - September 2015		250 bbl/d	WTI less 2.65 US $
Dated Brent - Collar			
April 2015 - September 2015	1	250 bbl/d	60.00 - 74.15 US $
July 2015 - September 2015	1	250 bbl/d	65.00 - 75.05 US $
July 2015 - October 2015	6	250 bbl/d	65.00 - 74.40 US $
July 2015 - June 2016	7	1,000 bbl/d	80.50 - 93.49 CAD $
July 2015 - June 2016	8	500 bbl/d	64.50 - 75.48 US $
October 2015 - December 2015	9	1,000 bbl/d	79.38 - 92.45 CAD $
October 2015 - June 2016	10	250 bbl/d	82.00 - 94.55 CAD $
January 2016 - June 2016	3	250 bbl/d	84.00 - 93.70 CAD $

(1) The contracted volumes increase to 750 boe/d for any monthly settlement periods above the contracted ceiling price.
(2) The contracted volumes increase to 1,500 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(3) The contracted volumes increase to 500 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(4) The contracted volumes increase to 1,250 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(5) The contract is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(6) The contracted volumes increase to 500 boe/d for any monthly settlement periods above the contracted ceiling price.
(7) The contracted volumes increase to 2,500 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(8) The contracted volumes increase to 1,000 boe/d for any monthly settlement periods above the contracted ceiling price.
(9) The contracted volumes increase to 2,000 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(10) The contracted volumes increase to 750 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).

	Note	Volume	Strike Price(s)
North American Natural Gas			
AECO - Collar			
April 2015 - October 2015		2,500 GJ/d	2.75 - 3.52 CAD $
April 2015 - December 2015		2,500 GJ/d	2.75 - 3.52 CAD $
October 2015 - December 2015		2,500 GJ/d	2.55 - 3.19 CAD $
November 2015 - March 2016		2,500 GJ/d	2.50 - 3.76 CAD $
January 2016 - December 2016		7,500 GJ/d	2.53 - 3.34 CAD $
April 2016 - October 2016		2,500 GJ/d	2.50 - 2.88 CAD $
AECO - Swap			
April 2015 - October 2015	1	10,000 GJ/d	2.98 CAD $
April 2015 - December 2015	2	2,500 GJ/d	2.99 CAD $
AECO Basis - Fixed Price Differential			
January 2015 - December 2015		5,000 mmbtu/d	Nymex HH less 0.68 US $
April 2015 - October 2015		7,500 mmbtu/d	Nymex HH less 0.62 US $
Nymex HH - Collar			
April 2015 - October 2015		10,000 mmbtu/d	3.36 - 4.01 US $
April 2015 - December 2015		2,500 mmbtu/d	3.50 - 4.11 US $
November 2015 - March 2016	3	5,000 mmbtu/d	3.25 - 3.86 US $
European Natural Gas			
NBP - Swap			
July 2015 - March 2016		2,592 GJ/d	6.42 EUR €
October 2015 - March 2016		10,368 GJ/d	6.54 EUR €
January 2016 - June 2016		5,184 GJ/d	6.24 EUR €
January 2016 - June 2016		2,592 GJ/d	6.82 US $
TTF - Collar			
January 2015 - December 2015		2,592 GJ/d	6.11 - 6.83 EUR €
April 2016 - December 2016		7,776 GJ/d	5.56 - 6.16 EUR €
TTF - Swap			
January 2015 - December 2015		11,664 GJ/d	6.45 EUR €
January 2015 - March 2016		5,184 GJ/d	6.40 EUR €
January 2015 - June 2016		2,592 GJ/d	6.07 EUR €
February 2015 - March 2016		5,184 GJ/d	6.24 EUR €
April 2015 - December 2015		2,592 GJ/d	6.30 EUR €
April 2015 - March 2016		5,832 GJ/d	6.18 EUR €
October 2015 - December 2015		2,592 GJ/d	5.69 EUR €
October 2015 - March 2016		2,592 GJ/d	6.64 EUR €
January 2016 - June 2016		2,592 GJ/d	6.10 EUR €
April 2016 - December 2016		2,592 GJ/d	5.91 EUR €
Electricity			
AESO - Swap			
January 2016 - December 2016		62.4 MWh/d	37.13 CAD $
AESO - Swap (Physical)			
January 2013 - December 2015		72.0 MWh/d	53.17 CAD $
US Dollar			
USD - Collar			
February 2015 - December 2015		2,500,000 US $/month	1.180 - 1.223 CAD $
USD - Forward			
February 2015 - December 2015		2,500,000 US $/month	1.198 CAD $

(1) On the last business day of each month, the counterparty has the option to increase the contracted volumes by an additional 10,000 GJ/d at the contracted price, for the following month.
(2) On the last business day of each month, the counterparty has the option to increase the contracted volumes by an additional 2,500 GJ/d at the contracted price, for the following month.
(3) The contracted volumes increase to 10,000 mmbtu/d for any monthly settlement periods above the contracted ceiling price.

Supplemental Table 3: Capital Expenditures

By classification ($M)	Three Months Ended Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Six Months Ended Jun 30, 2015	Jun 30, 2014
Drilling and development	90,173	174,311	117,975	264,484	286,815
Exploration and evaluation	-	-	17,098	-	44,633
Capital expenditures	90,173	174,311	135,073	264,484	331,448
Property acquisition	480	35	-	515	178,227
Corporate acquisition	-	-	381,139	-	381,139
Acquisitions	480	35	381,139	515	559,366

By category ($M)	Three Months Ended Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Six Months Ended Jun 30, 2015	Jun 30, 2014
Land	1,469	742	950	2,211	5,703
Seismic	1,723	1,493	1,869	3,216	5,301
Drilling and completion	31,976	82,343	42,083	114,319	148,619
Production equipment and facilities	43,957	74,755	60,547	118,712	129,302
Recompletions	9,288	7,115	13,459	16,403	17,685
Other	1,760	7,863	16,165	9,623	24,838
Capital expenditures	90,173	174,311	135,073	264,484	331,448
Acquisitions	480	35	381,139	515	559,366
Total capital expenditures and acquisitions	90,653	174,346	516,212	264,999	890,814

By country ($M)	Three Months Ended Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Six Months Ended Jun 30, 2015	Jun 30, 2014
Canada	22,265	114,884	418,294	137,149	538,001
France	16,793	34,114	37,614	50,907	75,581
Netherlands	18,885	4,333	21,513	23,218	41,631
Germany	3,231	968	630	4,199	173,697
Ireland	20,267	12,955	27,221	33,222	43,457
Australia	6,468	6,455	10,991	12,923	16,682
United States	2,744	637	-	3,381	-
Corporate	-	-	(51)	-	1,765
Total capital expenditures and acquisitions	90,653	174,346	516,212	264,999	890,814

Supplemental Table 4: Production

	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13	Q2/13	Q1/13	Q4/12	Q3/12
Canada												
Crude oil (bbls/d)	10,182	10,893	11,384	11,469	12,676	9,437	8,719	7,969	8,885	7,966	7,983	7,322
NGLs (bbls/d)	3,755	2,976	2,741	2,291	2,796	2,071	1,699	1,897	1,725	1,335	1,106	1,204
Natural gas (mmcf/d)	64.66	61.78	58.36	57.07	57.59	49.53	41.43	43.40	43.69	41.04	31.41	35.54
Total (boe/d)	24,713	24,165	23,851	23,272	25,070	19,763	17,322	17,099	17,892	16,140	14,323	14,449
% of consolidated	48%	48%	49%	47%	49%	42%	43%	41%	42%	41%	40%	40%
France												
Crude oil (bbls/d)	12,746	11,463	11,133	11,111	11,025	10,771	11,131	11,625	10,390	10,330	9,843	9,767
Natural gas (mmcf/d)	1.03	-	-	-	-	-	-	5.23	4.19	4.21	3.91	3.39
Total (boe/d)	12,917	11,463	11,133	11,111	11,025	10,771	11,131	12,496	11,088	11,032	10,495	10,333
% of consolidated	25%	23%	22%	22%	21%	23%	27%	30%	26%	29%	29%	28%
Netherlands												
NGLs (bbls/d)	112	63	81	63	96	69	62	48	50	96	70	41
Natural gas (mmcf/d)	32.43	36.41	31.35	38.07	40.35	43.15	37.53	28.78	38.52	36.91	33.03	34.59
Total (boe/d)	5,517	6,132	5,306	6,407	6,822	7,260	6,318	4,845	6,470	6,248	5,574	5,806
% of consolidated	11%	12%	11%	13%	13%	16%	15%	12%	15%	16%	15%	16%
Germany												
Natural gas (mmcf/d)	16.18	16.80	17.71	15.38	16.13	10.64	-	-	-	-	-	-
Total (boe/d)	2,696	2,801	2,952	2,563	2,689	1,773	-	-	-	-	-	-
% of consolidated	5%	6%	6%	5%	5%	4%	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	5,865	5,672	6,134	6,567	6,483	7,110	6,189	7,070	7,363	5,287	5,873	5,958
% of consolidated	11%	11%	12%	13%	12%	15%	15%	17%	17%	14%	16%	16%
United States												
Crude oil (bbls/d)	123	153	195	-	-	-	-	-	-	-	-	-
Consolidated												
Crude oil & NGLs (bbls/d)	32,783	31,220	31,668	31,501	33,076	29,458	27,800	28,609	28,413	25,014	24,875	24,292
% of consolidated	63%	62%	64%	63%	63%	63%	68%	69%	66%	65%	69%	66%
Natural gas (mmcf/d)	114.29	115.00	107.42	110.52	114.08	103.32	78.96	77.41	86.40	82.16	68.34	73.52
% of consolidated	37%	38%	36%	37%	37%	37%	32%	31%	34%	35%	31%	34%
Total (boe/d)	51,831	50,386	49,571	49,920	52,089	46,677	40,960	41,510	42,813	38,707	36,265	36,546

	YTD 2015	2014	2013	2012	2011	2010
Canada						
Crude oil (bbls/d)	10,535	11,248	8,387	7,659	4,701	2,778
NGLs (bbls/d)	3,367	2,476	1,666	1,232	1,297	1,427
Natural gas (mmcf/d)	63.23	55.67	42.39	37.50	43.38	43.91
Total (boe/d)	24,441	23,001	17,117	15,142	13,227	11,524
% of consolidated	48%	47%	41%	40%	38%	36%
France						
Crude oil (bbls/d)	12,108	11,011	10,873	9,952	8,110	8,347
Natural gas (mmcf/d)	0.52	-	3.40	3.59	0.95	0.92
Total (boe/d)	12,194	11,011	11,440	10,550	8,269	8,501
% of consolidated	24%	22%	28%	28%	23%	26%
Netherlands						
NGLs (bbls/d)	88	77	64	67	58	35
Natural gas (mmcf/d)	34.41	38.20	35.42	34.11	32.88	28.31
Total (boe/d)	5,823	6,443	5,967	5,751	5,538	4,753
% of consolidated	11%	13%	15%	15%	16%	15%
Germany						
Natural gas (mmcf/d)	16.49	14.99	-	-	-	-
Total (boe/d)	2,748	2,498	-	-	-	-
% of consolidated	5%	5%	-	-	-	-
Australia						
Crude oil (bbls/d)	5,769	6,571	6,481	6,360	8,168	7,354
% of consolidated	11%	13%	16%	17%	23%	23%
United States						
Crude oil (bbls/d)	138	49	-	-	-	-
Consolidated						
Crude oil & NGLs (bbls/d)	32,005	31,432	27,471	25,270	22,334	19,941
% of consolidated	63%	63%	67%	67%	63%	62%
Natural gas (mmcf/d)	114.64	108.85	81.21	75.20	77.21	73.14
% of consolidated	37%	37%	33%	33%	37%	38%
Total (boe/d)	51,113	49,573	41,005	37,803	35,202	32,132

Supplemental Table 5: Segmented Financial Results

	Three Months Ended June 30, 2015								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Drilling and development	21,881	16,697	18,885	3,231	20,267	6,468	2,744	-	90,173
Oil and gas sales to external customers	91,284	81,627	23,913	10,626	-	56,204	677	-	264,331
Royalties	(5,768)	(6,620)	(1,294)	(2,238)	-	-	(191)	-	(16,111)
Revenue from external customers	85,516	75,007	22,619	8,388	-	56,204	486	-	248,220
Transportation expense	(4,469)	(3,526)	-	(1,240)	(1,648)	-	-	-	(10,883)
Operating expense	(21,534)	(12,102)	(5,414)	(1,373)	-	(18,083)	(110)	-	(58,616)
General and administration	(5,510)	(4,874)	(454)	(1,435)	(628)	(1,141)	(963)	500	(14,505)
PRRT	-	-	-	-	-	(3,371)	-	-	(3,371)
Corporate income taxes	-	(9,316)	(2,347)	-	-	(5,134)	-	(547)	(17,344)
Interest expense	-	-	-	-	-	-	-	(14,550)	(14,550)
Realized gain on derivative instruments	-	-	-	-	-	-	-	3,081	3,081
Realized foreign exchange loss	-	-	-	-	-	-	-	(2,740)	(2,740)
Realized other income	-	-	-	-	-	-	-	204	204
Fund flows from operations	54,003	45,189	14,404	4,340	(2,276)	28,475	(587)	(14,052)	129,496

	Six Months Ended June 30, 2015								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Total assets	1,931,640	854,608	211,587	163,069	856,739	233,956	18,785	158,430	4,428,814
Drilling and development	136,730	50,811	23,218	4,199	33,222	12,923	3,381	-	264,484
Oil and gas sales to external customers	169,168	141,459	50,731	22,021	-	75,488	1,349	-	460,216
Royalties	(14,360)	(11,722)	(2,220)	(3,836)	-	-	(397)	-	(32,535)
Revenue from external customers	154,808	129,737	48,511	18,185	-	75,488	952	-	427,681
Transportation expense	(8,411)	(6,537)	-	(2,134)	(3,341)	-	-	-	(20,423)
Operating expense	(40,633)	(22,928)	(11,240)	(3,372)	-	(23,969)	(325)	-	(102,467)
General and administration	(9,525)	(9,985)	(1,191)	(3,043)	(1,140)	(2,595)	(2,043)	1,457	(28,065)
PRRT	-	-	-	-	-	(5,725)	-	-	(5,725)
Corporate income taxes	-	(23,597)	(4,735)	-	-	(5,711)	-	(924)	(34,967)
Interest expense	-	-	-	-	-	-	-	(27,848)	(27,848)
Realized gain on derivative instruments	-	-	-	-	-	-	-	9,338	9,338
Realized foreign exchange gain	-	-	-	-	-	-	-	566	566
Realized other income	-	31,775	-	-	-	-	-	426	32,201
Fund flows from operations	96,239	98,465	31,345	9,636	(4,481)	37,488	(1,416)	(16,985)	250,291

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 six months ended June 30, 2015, 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			Six Months Ended	
($M)	Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Jun 30, 2015	Jun 30, 2014
Cash flows from operating activities	134,668	22,647	149,592	157,315	327,830
Changes in non-cash operating working capital	(6,390)	95,041	64,103	88,651	88,577
Asset retirement obligations settled	1,218	3,107	2,381	4,325	5,032
Fund flows from operations	129,496	120,795	216,076	250,291	421,439
Expenses related to Corrib	2,276	2,205	1,823	4,481	3,693
Fund flows from operations (excluding Corrib)	131,772	123,000	217,899	254,772	425,132

	Three Months Ended			Six Months Ended	
($M)	Jun 30, 2015	Mar 31, 2015	Jun 30, 2014	Jun 30, 2015	Jun 30, 2014
Dividends declared	70,976	69,390	68,710	140,366	134,717
Issuance of shares pursuant to the dividend reinvestment and Premium Dividend™ plans	(42,301)	(21,378)	(19,149)	(63,679)	(38,034)
Net dividends	28,675	48,012	49,561	76,687	96,683
Drilling and development	90,173	174,311	117,975	264,484	286,815
Exploration and evaluation	-	-	17,098	-	44,633
Asset retirement obligations settled	1,218	3,107	2,381	4,325	5,032
Payout	120,066	225,430	187,015	345,496	433,163
Corrib drilling and development	(20,267)	(12,955)	(27,221)	(33,222)	(43,457)
Payout (excluding Corrib)	99,799	212,475	159,794	312,274	389,706

	As at		
('000s of shares)	Jun 30, 2015	Mar 31, 2015	Jun 30, 2014
Shares outstanding	109,806	107,718	106,620
Potential shares issuable pursuant to the VIP	2,820	3,043	2,751
Diluted shares outstanding	112,626	110,761	109,371

DIRECTORS

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

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 [4, 5]
Sugar Land, Texas

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

Sarah E. Raiss [3, 4]
Calgary, Alberta

Kevin J. Reinhart [2, 3]
Calgary, Alberta

Catherine L. Williams [2, 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
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mboe	thousand barrel of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmboe	million barrel of oil equivalent
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
NGLs	natural gas liquids
NGTL	NOVA Gas Transmission Ltd., a wholly owned subsidiary of TransCanada is the owner of a gas transmission system known as the NGTL system. The NGTL system is a 23,500 km pipeline that gathers natural gas for both use in Alberta, and to deliver it to provincial border points for export to North American markets.
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
TTF	the day-ahead price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

OFFICERS AND KEY PERSONNEL

CANADA

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 and Culture

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 G. Anderson
Managing Director – U.S. Business Unit

Timothy R. Morris
Director, 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

Bank of Montreal

Canadian Imperial Bank of Commerce

Royal Bank of Canada

The Bank of Nova Scotia

National Bank of Canada

Alberta Treasury Branches

HSBC Bank Canada

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian Branch

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

Union Bank, Canada Branch

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”)

EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

VERMILION ENERGY

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